EXHIBIT 1

APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS

Festival Hydro INC.

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2.1.2 Application Summary and Business Plan

2.1.2.1 Application

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15, 3 Schedule B, as amended (the "OEB Act");

AND IN THE MATTER OF an Application by Festival Hydro Inc. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2025.

(this "Application")

Applicant's Name Festival Hydro Inc. (the "Applicant" or "FHI").

1. The Applicant is a corporation incorporated pursuant to the Business Corporations Act (Ontario) with its head office at 187 Erie Street, Stratford, Ontario.

The Applicant carries on the business of distributing electricity within the communities of Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, and Zurich.

2. The Application has been prepared pursuant to the OEB's Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2012 (the "RRFE").

3. Unless specifically stated otherwise in the Cost of Service (COS) Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on December 15, 2022.

4. The Applicant has prepared a Consolidated Distribution System Plan ("DSP") in accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications last revised on December 15, 2022.

5. The Applicant acknowledges that the OEB will publish an update to the Cost of Capital Parameters and that these matters will affect the Revenue Requirement that the Applicant has requested in this Application.

6. The Applicant has filed a copy of the 2025 COS Checklist as an appendix to this Application.

7. Edits to any models have been listed in Attachment 1-19.

FHI has structured the Application in accordance with the Chapter 2 Filing Requirements, including the following nine exhibits, each filed as separate documents:

- Exhibit 1 Application Overview and Administrative Documents
- Exhibit 2 Rate Base and Capital
- Exhibit 3 Customer and Load Forecast
- Exhibit 4 Operating Expenses
- Exhibit 5 Cost of Capital and Capital Structure
- Exhibit 6 Revenue Requirement and Revenue Deficiency or Sufficiency
- Exhibit 7 Cost Allocation
- Exhibit 8 Rate Design
- Exhibit 9 Deferral and Variance Accounts

The Application itself is underpinned by FHI's business plan, which outlines the business strategic goals and initiatives FHI intends to achieve and how those goals relate to outcomes customers value. For ease of reference, a table summarizing FHI's strategic goals and initiatives from its business plan, has been reproduced as Table 1-1. The complete business plan can be found in Attachment 1-11 of this Exhibit.

2.1.2.2 Application Summary

Table 1-1 FHI's Strategic Goals and Initiatives

Strategic Goals and Initiatives	
Our People	•To ensure the safety of our staff is paramount. •To create a sustainable, motivated workforce and enhance productivity. •To be viewed as a great place to work.
Invest in New Operational Technology	•To mitigate costs where possible and improve operational efficiencies. •To improve internal and external communications. •To enhance and improve the customer experience.
Collaborate with Other Local Community Stakeholders	•Enhance long term viability.
Create Scale in the Utility Space	•To mitigate costs where possible and enhance efficiency. •Ensure financial viability. •Business continuity.

The Application is also based on FHI's Distribution System Plan (DSP) which outlines the overall condition of FHI's distribution system and the assets it is comprised of, as well as FHI's plans to ensure the safe and reliable delivery of electricity. The DSP has been provided as Attachment 2-2 of Exhibit 2.

The proposals of this Application have been summarized below:

A. Revenue Requirement

As will be discussed in detail throughout the Application, FHI has undergone significant change since it last filed for 2015 Rates. FHI has developed into a forward-looking organization and has needed to make substantial investments to catch up with its peers in terms of corporate systems (such as CIS and ERP), customer facing tools (such as SmartMap Outage Management Software), reliability improvements (such as voltage conversions and smart switches) and infrastructure improvements to protect and maintain its building assets. While all of these things have considerably improved the customer and employee experience, the reliability of the service territory, and protection of assets, this has come with cost increases in both capital and operating expenses. All the beneficiaries of these improvements should bear the financial burden of the incremental costs of these initiatives and not just the shareholder.

FHI is requesting approval of its proposed service revenue requirement of $17,377,042, an increase of 55% from its 2015 OEB approved service revenue requirement as shown in Table 1-2 below.

Table 1-2 Revenue Requirement

Application Summary	2015 Board Approved	2025 Test
Average Net Fixed Assets	52,171,404	66,444,572
Working Capital Allowance	9,607,355	5,729,053
Rate Base	**61,778,759**	**72,173,625**
Working Capital Allowance	13.00%	7.50%
Regulated Return on Capital	3,797,664	4,756,852
OM&A including Property Taxes	5,188,507	9,430,261
Amortization Expense	2,082,559	2,969,170
PILs	142,098	220,759
Service Revenue Requirement	**11,210,828**	**17,377,042**
Less: Revenue Offsets	755,699	1,166,332
Base Revenue Requirement	**10,455,129**	**16,210,710**

The variance in the base revenue requirement between 2025 proposed and 2015 OEB approved is approximately $5.8 million, however approximately $2.9M has been recovered through billing determinants and annual inflationary rate increases since 2015, leaving a remaining deficiency of approximately $2.8 million.

The main drivers of the increase are:

- A 27% increase in average net fixed assets or approximately 2.7% per year. There has been an increase in work completed but also the cost of capital projects and materials have increased dramatically since 2019. This also impacts the Regulated Return on Capital and Amortization expense.
- An 82% increase in Operating, Maintenance and Administration (OM&A) since 2015. While this is a significant increase, FHI is seeing double digit increases in many operating expenses annually. In addition, there have been many new or changing initiatives and costs incurred in the past ten years such as Software as

a Service expenses, Cyber Security, and new regulatory expenses. Changes to OM&A are discussed in greater detail in Exhibit 4.

- This is offset by the 44% decrease in the Working Capital Allowance (WCA). This is due to a change in the OEB allowed rate from 13% in 2015 to 7.5% in 2025.
- This is also offset by a 54% increase in revenue offsets. This is mostly due to increases in administration charges on billable work and leasing revenue. In addition, there was a significant loss in 2015 which offset other revenues. Other Revenues are discussed further in Exhibit 6.

B. Load Forecast Summary

FHI's customer and connection growth has been provided in Table 1-3. Over the past 10 years FHI has seen a moderate amount of growth in residential and small commercial customers and a decrease in large commercial customers. Exhibit 3 provides the details and assumptions supporting the forecasted number of customers.

Table 1-3 Customer and Connection Growth

Year	Billed Actual (GWh)	Growth (GWh)	Percent Change (%)	Billed Weather Normal (GWh)	Growth (GWh)	Percent Change (%)	Customer/Connection Count	Growth (GWh)	Percent Change (%)
2015 Board Approved	593.7						27,375		
2014 Actual	601.8			603.0			27,093		
2015 Actual	605.4	3.7	0.6%	606.7	3.7	0.6%	27,298	205	0.8%
2016 Actual	607.6	2.1	0.4%	604.4	(2.4)	-0.4%	27,542	244	0.9%
2017 Actual	592.8	(14.8)	-2.4%	595.8	(8.6)	-1.4%	27,833	292	1.1%
2018 Actual	613.2	20.4	3.4%	607.0	11.2	1.9%	28,101	268	1.0%
2019 Actual	611.2	(2.0)	-0.3%	610.9	4.0	0.7%	28,205	104	0.4%
2020 Actual	585.3	(25.9)	-4.2%	583.3	(27.6)	-4.5%	28,277	72	0.3%
2021 Actual	596.8	11.6	2.0%	595.2	11.9	2.0%	28,558	281	1.0%
2022 Actual	614.8	17.9	3.0%	614.3	19.1	3.2%	28,919	361	1.3%
2023 Actual	603.6	(11.2)	-1.8%	611.8	(2.5)	-0.4%	29,267	348	1.2%
2024 Bridge - Normalized	606.9	3.3	0.5%	606.9	(4.9)	-0.8%	29,547	280	1.0%
2025 Test - Normalized	605.4	(1.4)	-0.2%	605.4	(1.4)	-0.2%	29,832	285	1.0%

FHI's load growth has been prepared using the same methodology approved in its 2015 COS proceeding. Table 1-4 provides the summary of total load forecast.

Table 1-4 Summary of Total Load Forecast

Year	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Actual kWh Purchases		624,159,352	624,543,695	607,172,998	633,220,675	626,711,582	604,483,597	610,737,932	624,627,795	622,407,594		
Predicted kWh Purchases		620,652,687	626,030,371	618,123,675	628,373,961	622,991,159	601,329,176	624,451,396	621,732,226	612,959,004	623,479,098	622,011,914
% Difference between Actual and Predicted Purchases		(0.6%)	0.2%	1.8%	(0.8%)	(0.6%)	(0.5%)	2.2%	(0.5%)	(1.5%)		
Loss Factor											1.0274	1.0274
Total Billed											606,861,805	605,433,725
By Class												
Residential												
Customers	18,224	18,197	18,417	18,678	18,942	19,073	19,224	19,481	19,756	20,059	20,299	20,541
kWh	140,396,363	138,916,796	139,158,722	134,065,184	146,158,990	143,256,844	151,219,360	152,437,380	153,959,248	149,185,943	152,450,631	153,701,712
General Service < 50 kW												
Customers	2,029	2,052	2,067	2,081	2,089	2,082	2,084	2,095	2,107	2,125	2,136	2,146
kWh	64,120,602	63,555,664	63,059,837	62,117,168	64,384,300	62,985,946	58,159,694	57,918,968	61,132,367	61,400,428	62,309,194	62,385,122
General Service > 50 to 4999 kW												
Customers	226	218	217	219	217	220	221	215	209	210	208	207
kWh	357,185,184	369,534,512	373,231,715	365,627,458	368,587,747	370,357,504	341,875,528	351,758,215	363,572,115	357,652,061	356,728,281	353,920,347
kW	936,133	946,403	911,298	894,837	912,782	918,770	866,278	878,372	881,049	876,527	887,533	880,547
Large Use												
Customers	1	1	1	1	1	1	1	1	1	1	1	1
kWh	22,706,506	24,639,648	25,183,382	24,407,204	26,894,138	27,745,078	27,495,994	28,340,499	29,487,369	29,085,391	29,085,391	29,085,391
kW	35,166	39,140	38,848	36,858	43,546	41,926	41,219	41,849	44,238	43,002	44,439	44,439
Sentinel Lighting												
Connections	41	44	44	43	41	38	37	36	36	36	35	34
kWh	149,276	130,859	132,438	129,472	110,217	97,846	95,110	95,778	99,494	100,504	97,803	95,176
kW	353	364	368	360	306	272	264	267	276	279	272	264
Street Lighting												
Connections	6,626	6,558	6,568	6,582	6,579	6,560	6,479	6,390	6,376	6,400	6,400	6,400
kWh	4,532,631	4,307,271	2,722,097	2,622,813	2,481,816	2,482,833	2,394,908	2,328,792	2,546,051	2,364,162	2,364,162	2,364,162
kW	11,925	11,103	7,006	6,205	6,104	6,667	6,381	6,226	6,245	5,749	6,011	6,011
Unmetered Scattered Load												
Connections	227	229	228	230	230	229	229	338	433	435	467	501
kWh	657,094	663,213	665,566	659,309	643,588	648,488	671,398	728,877	702,388	702,928	754,577	810,020
Wholesale Market Participant												
Customers	1	1	1	1	2	2	2	2	2	2	2	2
kWh	3,988,503	3,801,987	3,410,848	3,139,758	3,931,816	3,611,938	3,347,054	3,211,585	3,263,932	3,084,831	3,084,831	3,084,831
kW	6,590	6,663	6,317	5,724	41,919	52,613	28,559	28,641	10,175	10,024	17,350	17,350
Total												
Customer/Connections	27,375	27,298	27,542	27,833	28,101	28,205	28,277	28,558	28,919	29,267	29,547	29,832
kWh	593,736,159	605,549,950	607,564,604	592,768,367	613,192,612	611,186,477	585,259,047	596,820,094	614,762,964	603,576,249	606,874,871	605,446,761
kW from applicable classes	990,167	1,003,671	963,836	943,984	1,004,657	1,020,248	942,702	955,354	941,983	935,582	955,605	948,612

Based on the load forecast methodology, the 2025 Test Year kWh forecast is 605,446,761 kWh, an 11,710,602 kWh or 2.0% increase from the 2015 Board Approved amount. Forecasted average customer count for the 2025 Test Year is 29,832, a 2,457 or 9.0% increase from the 2015 Board Approved amount. Table 1-5 summarizes the customer/connections and their respective consumption and demand compared to the 2015 Board Approved amounts. The forecasting method for the average number of customer and connections is based on the historic geomean.

Table 1-5 Test Year Compared to 2015 Board Approved

Rate Class	2015 Board Approved			2025 Test Year			Variance		
	#	kWh	kW	#	kWh	kW	#	kWh	kW
Residential	18,224	140,396,363		20,541	153,701,712		2,317	13,305,349	-
General Service < 50 kW	2,029	64,120,602		2,146	62,385,122		117	- 1,735,480	-
General Service 50 to 4,999 kW	227	361,173,687	942,723	209	357,005,178	897,897	- 18	- 4,168,509	- 44,826
Large Use	1	22,706,506	35,166	1	29,085,391	44,439	-	6,378,885	9,273
Sentinel Lighting	41	149,276	353	34	95,176	264	- 7	- 54,100	- 89
Street Lighting	6,626	4,532,631	11,925	6,400	2,364,162	6,011	- 227	- 2,168,469	- 5,914
Unmetered Scattered Loads	227	657,094		501	810,020		274	152,926	-
Total	**27,375**	**593,736,159**	**990,167**	**29,832**	**605,446,761**	**948,612**	**2,457**	**11,710,602**	**- 41,555**

C. Rate Base and Distribution System Plan (DSP)

As indicated in Table 1-6 below, FHI's 2025 Test Year rate base is $72.2M. Rate base has grown by $10.4M (17%) since FHI's last approved COS Application in 2015. The increase is driven by a 27% growth in the average net book value of assets, partially offset by a reduction in the working capital allowance. The growth in the average net book value of assets is the direct result of the capital expenditures which FHI has incurred over the past ten years. These expenditures are outlined in Exhibit 2 of this Application.

Table 1-6 Summary of Rate Base

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets Opening Balance	90,816,914	55,573,235	57,050,939	59,135,138	61,614,375	64,455,048
Gross Fixed Assets Closing Balance	93,182,896	57,050,939	59,135,138	61,614,375	64,455,048	67,200,894
Average Gross Fixed Assets	**91,999,905**	**56,312,087**	**58,093,039**	**60,374,757**	**63,034,712**	**65,827,971**
Accumulated Depreciation Opening Balance	38,761,080	2,242,612	4,409,458	6,394,835	8,690,123	10,783,036
Accumulated Depreciation Closing Balance	40,895,920	4,409,458	6,394,835	8,690,123	10,783,036	12,952,345
Average Accumulated Depreciation	**39,828,500**	**3,326,035**	**5,402,146**	**7,542,479**	**9,736,579**	**11,867,691**
Average Net Book Value	**52,171,405**	**52,986,052**	**52,690,892**	**52,832,278**	**53,298,132**	**53,960,280**
Working Capital	73,902,730	76,680,740	84,312,292	76,622,312	74,377,176	76,937,488
Working Capital Allowance %	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
Working Capital Allowance	**9,607,355**	**9,968,496**	**10,960,598**	**9,960,901**	**9,669,033**	**10,001,873**
Rate Base	**61,778,759**	**62,954,548**	**63,651,490**	**62,793,179**	**62,967,165**	**63,962,153**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets Opening Balance	67,200,894	66,981,996	69,712,958	72,673,651	76,880,111	84,377,938
Gross Fixed Assets Closing Balance	66,981,996	69,712,958	72,673,651	76,880,111	84,377,938	91,787,288
Average Gross Fixed Assets	**67,091,445**	**68,347,477**	**71,193,305**	**74,776,881**	**80,629,025**	**88,082,613**
Accumulated Depreciation Opening Balance	12,952,345	12,489,859	14,179,382	15,579,227	17,418,515	20,126,776
Accumulated Depreciation Closing Balance	12,489,859	14,179,382	15,579,227	17,418,515	20,126,776	23,149,305
Average Accumulated Depreciation	**12,721,102**	**13,334,620**	**14,879,305**	**16,498,871**	**18,772,645**	**21,638,041**
Average Net Book Value	**54,370,343**	**55,012,857**	**56,314,000**	**58,278,010**	**61,856,379**	**66,444,572**
Working Capital	78,623,069	66,713,670	64,900,191	69,807,896	67,865,459	76,387,370
Working Capital Allowance %	13.00%	13.00%	13.00%	13.00%	13.00%	7.50%
Working Capital Allowance	**10,220,999**	**8,672,777**	**8,437,025**	**9,075,026**	**8,822,510**	**5,729,053**
Rate Base	**64,591,342**	**63,685,634**	**64,751,025**	**67,353,037**	**70,678,889**	**72,173,625**

The working capital allowance in the Test Year is $5.7M. This is a decrease of $3.9M or 40% from the 2015 OEB approved amount, primarily due to the decrease in working capital allowance rate used in 2025 of 7.5% from the former rate of 13% used in 2015. Working Capital related expenses have grown to $76.4M in 2025 from $73.9M or 3% over the past 10 years. An analysis of the working capital is provided in Exhibit 2, 2.2.5 Allowance for Working Capital.

FHI's Distribution System Plan was developed to balance the needs and preferences of its customers and the needs of the distribution system. FHI formed its plans through asset management processes, customer engagement, and coordination with third parties. The major drivers of FHI's Distribution System Plan include the following:

- Investment in grid modernization which aims to reduce the number of customers affected by outages, re-route power when outages occur, provide improved outage information to customers, and identify and/or locate outages quickly.
- Advanced Metering Infrastructure 2.0 (AMI 2.0) Deployment to replace FHI's current and increasingly failing AMI in an economic and operationally efficient manner, thereby maintaining compliance with regulatory metering and billing requirements. This investment ensures that customers will continue to receive the high level of billing accuracy they are accustomed to. It also ensures that customers continue to stay connected to safe reliable power, while enabling greater access to flexible service options.
- Ensuring System Capacity and flexibility to facilitate load growth, Distributed Energy Resources (DER's), and new customer connections.
- Executing a sustainable, condition-based infrastructure replacement strategy.
- Maintaining a safe and reliable system for workers and the public.
- Improve operational efficiencies using new technologies.
- Continue to incorporate customer feedback and comments into planning and prioritization of projects.

FHI's capital expenditures have increased in 2025 by $4.9M or 196% since the last rebasing Application. As indicated in Table 1-7 below, the largest increases are in the System Access and System Renewal categories. The increase in System Access is driven by AMI 2.0 and System Renewal has been driven by the deteriorating condition of FHI's distribution system. Over the past 10 years, FHI has increased its spending to ensure it was replacing assets at a rate that maintained the overall condition of assets and health of its system, while targeting assets most critical to improve reliability.

Table 1-7 Capital Expenditure Summary

OEB Investment Category	Historical Period														
	2015			2016			2017			2018			2019		
	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %
System Access	322	713	121.7%	328	583	77.6%	335	733	119.3%	341	1,378	304.1%	348	1,200	245.3%
System Renewal	1,490	1,706	14.5%	1,513	1,427	-5.7%	1,539	1,644	6.8%	1,565	1,565	0.0%	1,592	1,768	11.1%
System Service	310	238	-23.3%	314	38	-87.8%	316	29	-90.7%	318	38	-88.1%	320	30	-90.7%
General Plant	500	653	30.7%	427	555	30.0%	826	549	-33.6%	445	837	88.0%	415	613	47.8%
Totals	**2,622**	**3,309**	**26.2%**	**2,582**	**2,603**	**0.8%**	**3,016**	**2,956**	**-2.0%**	**2,669**	**3,818**	**43.1%**	**2,675**	**3,611**	**35.0%**
Capital Contributions	120	334	178.3%	120	207	72.2%	120	372	209.8%	120	585	387.8%	120	444	269.8%
Net Capital Expenditures	**2,502**	**2,975**	**18.9%**	**2,462**	**2,396**	**-2.7%**	**2,896**	**2,584**	**-10.8%**	**2,549**	**3,233**	**26.8%**	**2,555**	**3,168**	**24.0%**
Total O&M	**2,104**	**2,156**	**2.4%**	**2,085**	**2,133**	**2.3%**	**2,124**	**2,269**	**6.8%**	**2,171**	**2,602**	**19.9%**	**2,591**	**2,408**	**-7.1%**

OEB Investment Category	Historical Period												Bridge Year		
	2020			2021			2022			2023			2024		
	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Budget	Var %
System Access	721	1,086	50.8%	712	1,091	53.2%	863	1,013	17.4%	805	1,186	47.4%	1,212	1,212	0.0%
System Renewal	1,935	1,627	-15.9%	1,866	2,027	8.6%	2,044	2,222	8.7%	2,469	2,114	-14.4%	2,236	2,236	0.0%
System Service	55	51	-7.5%	55	6	-89.7%	55	34	-38.5%	75	110	46.9%	77	77	0.0%
General Plant	973	460	-52.7%	1,040	876	-15.7%	969	907	-6.4%	1,665	1,927	15.8%	4,193	4,193	0.0%
Totals	**3,683**	**3,225**	**-12.5%**	**3,673**	**4,000**	**8.9%**	**3,931**	**4,175**	**6.2%**	**5,014**	**5,337**	**6.4%**	**7,717**	**7,717**	**0.0%**
Capital Contributions	200	466	132.8%	200	481	140.7%	200	343	71.7%	400	447	11.7%	219	219	0.0%
Net Capital Expenditures	**3,483**	**2,759**	**-20.8%**	**3,473**	**3,519**	**1.3%**	**3,731**	**3,832**	**2.7%**	**4,614**	**4,891**	**6.0%**	**7,498**	**7,498**	**0.0%**
Total O&M	**2,678**	**2,601**	**-2.9%**	**2,642**	**2,445**	**-7.5%**	**2,845**	**2,904**	**2.1%**	**3,087**	**3,049**	**-1.2%**	**3,352**	**3,352**	**0.0%**

OEB Investment Category	Test Year	Forecast Period			
	2025	2026	2027	2028	2029
	Budget	Forecast	Forecast	Forecast	Forecast
System Access	2,399	2,463	2,531	2,601	1,743
System Renewal	3,101	3,351	3,421	3,505	3,590
System Service	359	374	384	397	409
General Plant	1,878	1,299	1,262	1,274	1,585
Totals	**7,737**	**7,487**	**7,598**	**7,777**	**7,327**
Capital Contributions	327	332	338	345	352
Net Capital Expenditures	**7,410**	**7,156**	**7,260**	**7,432**	**6,974**
Total O&M	**3,515**	**3,620**	**3,729**	**3,841**	**3,956**

System Access: Typically, the 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 these investments is driven by the needs of external parties and is considered mandatory. Over the forecast period, FHI also plans to invest in an AMI 2.0 network to replace the existing AMI infrastructure. This will be one of FHI's largest investments. The timing of this investment is driven by the age and performance history of the existing AMI infrastructure, as well as the enhancements that have been made to what LDC's and customers can receive from an AMI 2.0 solution. The benefits of this project can be found in Appendix A of the DSP. System Access is the second largest planned capital expenditure over the 2025–2029 forecast period representing 31% of overall gross spending. Other than the AMI 2.0 redeployment costs, the proposed expenditure level is estimated based on the historic spending levels and specific information available from developers, customers and other third parties about planned projects at the time of preparation of this DSP.

System Renewal: Expenditures within the System Renewal category is largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. The Asset Condition Assessment (ACA), included in the DSP, provided a starting point for FHI to use to determine which investments are required over the DSP period. System Renewal is the largest planned capital expenditure over the 2025–2029 forecast period representing 45% of overall spending. The level of investments required over the forecast period was determined using FHI's asset management process, which is described in detail in Section 5.3.1 of the DSP, and the ACA was used to assist in prioritizing investments in asset classes. Major programs within the System Renewal category include the renewal and replacement of deteriorated assets at the end of their service life, including poles, transformers, underground cable, transformer station assets, and switchgear. Unplanned System Renewal projects are also budgeted each year to allow for replacement of electrical infrastructure damaged by inclement weather, unclaimed vehicle accidents or those identified through inspections or testing as needing immediate replacement.

System Service: System service investments are modifications to FHI's distribution system to ensure the distribution system continues to meet FHI's operational objectives (system efficiency, DER integration, grid flexibility, etc.) while addressing anticipated future customer electricity service requirements. System service investments represent 5% of FHI's overall budgeted net capital expenditures over the forecast period and include 4kV Voltage Conversion and Distribution Automation.

General Plant: Expenditures in the General Plant category is driven by the need to modify, replace, or add to assets that are not part of the distribution system but support FHI's 24/7 operations. The items within this category are important and contribute to the safe and reliable operation of a distribution system. If General Plant investments are ignored or deprioritized this could lead to future operational risks or increased investments in future years. General plant investments represent 19% of FHI's overall budgeted net capital expenditures over the forecast period. The proposed expenditure level is based on the outputs of the ACA, projects required due to technological obsolescence or lack of vendor support, the risk of not being in regulatory compliance, as well as recommendations from third party assessments and reports.

D. Operations, Maintenance and Administration Expense

FHI is seeking recovery of $9.4M of OM&A expenses in the 2025 Test Year. This is an increase of $4.2M or 82% from its 2015 OEB approved amount. Table 1-8 provides a breakdown of the major cost drivers of this increase.

Table 1-8 Cost Driver Table

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Opening Balance[2]	5,188,507	5,354,477	5,743,002	5,698,824	6,387,564	6,114,102	6,177,972	6,144,863	6,881,608	7,604,454	8,369,252
Billing, Collecting and Office Costs	38,016	66,027	53,589	67,403	56,820	(37,701)	84,059	(71,335)	(36,117)	35,053	82,913
Board of Directors	6,354	1,834	5,783	(8,739)	8,096	76,059	(18,990)	16,188	(11,990)	18,187	8,596
Labour & Burdens	37,705	(69,658)	(29,038)	357,788	174,627	(74,308)	(104,019)	180,072	472,443	508,175	595,295
Other Employee Costs (Training/Dev/Supplies)	19,285	(3,168)	(31,723)	76,487	13,464	(55,512)	(58,392)	115,621	55,437	19,037	39,120
Contract Labour / Services	24,303	152,977	73,153	172,254	(340,923)	(48,563)	99,973	290,736	129,243	57,162	55,578
Software, Support and Maintenance Costs	400	(1,999)	16,430	16,514	(9,593)	46,086	13,162	45,086	56,803	61,849	162,011
Property Maintenance	6,907	66,354	10,981	(55,288)	(23,506)	45,596	(3,036)	59,147	19,050	57,730	14,771
Third Party Services (Legal/Insur/Audit)	13,100	188,829	(185,340)	51,039	(97,599)	96,817	(2,570)	53,590	93,913	(43,128)	36,367
Operations Maintenance & Vehicles	19,900	(12,671)	41,987	11,280	(54,847)	15,396	(43,297)	47,639	(55,937)	50,732	66,359
Closing Balance	**5,354,477**	**5,743,002**	**5,698,824**	**6,387,564**	**6,114,102**	**6,177,972**	**6,144,863**	**6,881,608**	**7,604,454**	**8,369,252**	**9,430,261**

Cost pressures and increases are discussed in detail in Exhibit 4 as well as in the Business Plan included in Attachment 1-11. FHI has seen increasing cost pressures since 2015, however there was a large increase in the most recent years due to a perfect storm of cost pressures. Some of these cost pressures include high interest rates, high inflation, low supply labour market and challenges with the supply chain. All of these issues are being seen across all industries, so not only does it impact FHI's direct costs (labour), but the cost increases are also built into all vendor costs as well.

FHI exceeded OEB Approved amounts in OM&A, Capital Expense and Rate Base compared to 2015 Actual. The OEB approved the full ask of Management at that time. This demonstrates that the requests in 2015 were not sufficient to manage the business needs and did not assist with future planning and stability of the organization.

E. Cost of Capital

FHI has provided its proposed capital structure and cost of capital in Table 1-9 below. The cost of capital has been set using the OEB's current cost of capital parameters (for 2024 applications) for both the short-term debt rate and return on equity. FHI intends to update its Application with the OEB's 2025 cost of capital parameters when they are issued. The long-term debt rate is based on the weighted average cost of FHI's long-term debt rate, as described in Exhibit 5.

Table 1-9 Capital Structure and Cost of Capital

Test Year: 2025				
Particulars	Capitalization Ratio		Cost Rate	Return
	%	$	%	$
Debt				
Long-Term Debt	56%	40,417,230	4.75%	1,918,119
Short-Term Debt	4%	2,886,945	6.23%	179,857
Total Debt	60%	43,304,175	4.84%	2,097,975
Equity				
Common Equity	40%	28,869,450	9.21%	2,658,876
Preferred Shares	0%	-	0%	-
Total Equity	40%	28,869,450	9.21%	2,658,876
Total	100%	72,173,625	6.59%	4,756,852

F. Cost Allocation and Rate Design

There were three rate classes whose proposed revenue-to-cost ratios were above their respective band thresholds: General Service < 50 kW, Large Use, and Unmetered Scattered Load. FHI has proposed a reduction in the revenues allocated to each of these classes, to bring them to the top of their respective bands. This resulted in increases in revenue from Residential, Street Lighting and Sentinel lighting rate classes. FHI is proposing for the GS 50 to 4,999 kW rate class to remain at Status Quo. Table 1-10 provides the Revenue to Cost Ratios from FHI's last Cost of Service, what the ratios would have been before the proposed changes (Status Quo) and the Revenue to Cost Ratios proposed in this Application, for each rate class.

Table 1-10 Revenue to Cost Ratios

Rate Class	2015 Board Approved	2025 Updated Cost Allocation Study	2025 Proposed Ratios	Board Targets
	%	%	%	%
Residential	101.88%	94.21%	95.72%	85 - 115
GS < 50 kW	118.16%	130.12%	120.00%	80 - 120
G.S. > 50 kW to 4999 kW	86.25%	100.87%	100.87%	80 - 120
Large Use	106.38%	115.22%	115.00%	85 - 115
Sentinel Lighting	86.25%	91.14%	95.72%	80 - 120
Street Lighting	120.00%	76.04%	95.72%	80 - 120
Unmetered Scattered Load	120.00%	129.01%	120.00%	80 - 120

The proposals set forth in this Application will change the rates for all rate classes. However, there were no changes that exceeded a total bill impact in excess of 10% and therefore no mitigation plans have been provided.

FHI also has not proposed any new rate classes or any changes to the definition of its existing customer classes.

G. Deferral and Variance Accounts

As part of this Application, FHI is seeking recovery of its Deferral and Variance Account (DVA) balances of $(569,279), as outlined in Table 1-11. FHI is seeking disposition over a one-year period through the rate riders outlined in Exhibit 9 – Deferral and Variance Accounts. Exhibit 9 provides all the details on Deferral and Variance Accounts.

Table 1-11 Deferral and Variance Account Balances for Recovery

DVA Category	Disposition ($)
Group 1 Accounts (excluding Global Adjustment)	- 425,963
Global Adjustment	277,033
Total Group 1 (including Global Adjustment)	- 148,931
Group 2	- 420,349
Total DVA Balances for Disposition	**- 569,279**

H. Bill Impacts

The bill impacts resulting from the proposals within this Application are summarized in Table 1-12 below. The bill impacts are to be based on the commodity rates based on time-of-use and regulatory charges held constant. Exhibit 8 – Rate Design outlines the calculations used to determine these rate impacts. The Distribution Bill Impact percentage included in Table 1-12 is the percentage impact of the change in monthly fixed charge and distribution volumetric rate.

There are no customers that are uniquely affected by proposals made in this Application with the exception of those impacted by gross load billing. This is discussed further in 2.1.5.

Table 1-12 below, provides the bill impacts FHI proposes to be used in the Notice of Application.

Table 1-12 Bill Impacts

Rate Impact Summary of Typical Monthly Usage by Rate Class								
Rate Class	*kWh*	*kW*	*# of Connections*	*2024 Bill $*	*2025 Bill $*	*$ Difference*	*Total Bill Impact %*	*Distribution Bill Impact %*
Residential	750			$129.51	$134.02	$4.52	3.49%	23.1%
GS < 50 kW	2,000			$332.31	$329.92	$(2.38)	-0.72%	11.1%
GS 50 to 4,999 kW	51,100	100		$7,632.50	$7,270.75	$(361.75)	-4.74%	19.6%
Large Use	2,555,000	5,000		$353,737.38	$341,646.85	$(12,090.53)	-3.42%	17.6%
Unmetered Scattered Load	340		1	$56.78	$57.32	$0.54	0.95%	12.0%
Sentinel Lighting	423	1	1	$69.44	$72.72	$3.28	4.73%	27.7%
Street Lighting	239,805	657	1	$36,024.29	$36,333.56	$309.27	0.86%	54.6%
GS < 50 kW	10,000			$1,520.88	$1,493.55	$(27.32)	-1.80%	11.1%
Residential - 10% Consumption Percentile	277			$67.23	$73.09	$5.86	8.71%	23.1%
GS 50 to 4,999 kW	306,600	600		$44,247.99	$41,753.01	$(2,494.98)	-5.64%	19.6%
Residential - Retailer	750			$118.29	$119.34	$1.05	0.88%	23.1%
GS < 50 kW - Retailer	2,000			$302.79	$291.15	$(11.64)	-3.84%	11.1%

2.1.3 Administration

2.1.3.1 Primary Contact Information

In accordance with the OEB's Filing Requirements this section of the Application provides the information relating to the administration of this Application.

Ms. Alyson Conrad

Chief Financial Officer

187 Erie Street, Stratford ON, N5A 2M6

Telephone: (519) 271-4700 ext. 221

Email: aconrad@festivalhydro.com

And

Mr. Jeff Graham

President and Chief Executive Officer

187 Erie Street, Stratford ON, N5A 6M6

Telephone: (519) 271-4703 ext. 241

Email: grahamj@festivalhydro.com

2.1.3.2 The Applicant's Legal Representation

Borden Ladner Gervais LLP

40 King Street West

40th Floor

Toronto ON, M5H 3Y5

Primary Legal Contact:

John A.D. Vellone

Lawyer

Telephone: (416) 367-6730

Email: jvellone@blg.com

2.1.3.3 Internet Address and Social Media Accounts

The Application and related materials will be posted on FHI's website and available for customers to view at: www.festivalhydro.com.

FHI also communicates with its customers using its X (formally Twitter) account (@festival_hydro) and Facebook (facebook.com/festivalhydro).

2.1.3.4 Statement of Publication

FHI will follow the OEB's instructions regarding the publication of notice in relation to this Application. FHI proposes that the Notice of Application be published in the Stratford Beacon Herald (paid publication) which has the highest circulation in FHI's service area.

2.1.3.5 Materiality Threshold

FHI's materiality threshold has been determined as 0.5% of distribution revenue requirement which equates to $81,054, as indicated in Table 1-13 below. FHI has applied a materiality of $80,000 in its analysis throughout the Application.

Table 1-13 Materiality Threshold

Description	2025 Test Year
Base Revenue Requirement	16,210,710
Materiality Threshold 0.5%	81,054
Materiality Used	**80,000**

2.1.3.6 Requested Form of Hearing

The rate impacts resulting from this Application are below the materiality threshold of 10% on the total bill for all rate classes. FHI therefore requests that this Application be heard by way of a written hearing to expedite the proceedings.

2.1.3.7 Requested Effective Date of Rate Order

FHI requests that the OEB make its Rate Order effective January 1, 2025. In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of January 1, 2025, the Applicant requests that the OEB declare its current rates interim, effective January 1, 2025, pending the implementation of the OEB's Rate Order for the 2025 rate year.

2.1.3.8 Change in Methodology

The methodologies used in this Application are consistent with those applied in FHI's last COS Application (EB-2014-0073). Historical amounts are the same as approved by the Board in EB-2014-0073. FHI has also made changes as required as the Filing Requirements have evolved since the 2015 COS Application.

2.1.3.9 OEB Directions from previous Decisions and/or Orders

FHI only had one utility-specific direction from the Board in or since its last COS Application (EB-2014-0073). In FHI's 2023 IRM Application (EB-2022-0032) it was noted that "Festival Hydro applied for approval of LRAM-eligible amounts for the years 2023 to 2027 on a prospective basis, arising from persisting savings from completed CDM programs. Festival Hydro's application indicated that this would be accounted for in a true-up in its next cost of service filing." FHI has reviewed its previous submission and there was only one project post approval. The impact of this additional project would likely be less than $2K in favour of FHI. FHI is not intending to file a claim for this true up as the third-party assistance costs for LRAM would exceed the value.

2.1.3.10 Conditions of Service

FHI's current Conditions of Service are available on its website at https://www.festivalhydro.com/projects-operations/conditions-service. There has been one update to the Conditions of Service since the last COS Application which was effective February 1, 2023.

All the changes that were included in the February 1, 2023, update have been provided in Attachment 1-7.

There are no rates or charges listed in the Conditions of Service that are not on the distributor's Tariff of Rates and Charges.

2.1.3.11 Current Application

As part of this Application, FHI is requesting changes to its Tariff of Rates and Charges regarding specific service charges, specifically changing the words Income Tax Letter to Bill Copy Charge and changing Service Call – Customer Owned Equipment and Service Call – After Regular Hours to be listed as Time & Materials instead of $30 and $165 respectively. FHI also requests a note be added to the Tariff Sheet regarding Gross Load billing as outlined in Exhibit 8 –2.8.2.

2.1.3.12 Corporate and Utility Organizational Structure

FHI is wholly owned by the City of Stratford. FHI is the licensed distributor of electricity. Festival Hydro Services Inc. (FHSI) is also wholly owned by the City of Stratford. FHI and FHSI have the same President and CEO and this individual is the main contact with the parent company officials. There are also City of Stratford Council members on the FHI and FHSI Board of Directors and as such represent reporting relationships between utility management and parent company officials.

A chart illustrating FHI's corporate structure is provided below in Figure 1-1 followed by a corporate organization chart in Figure 1-2.

Figure 1-1 Corporate Structure

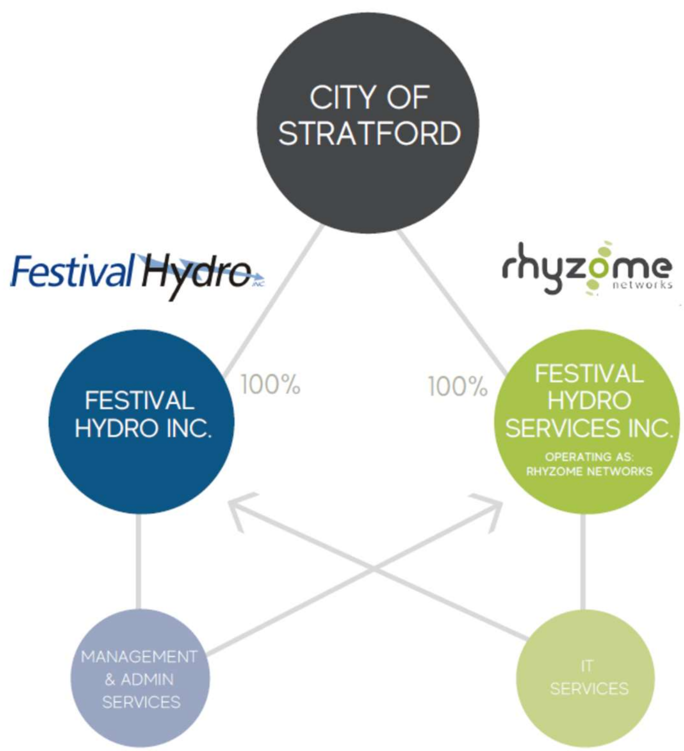
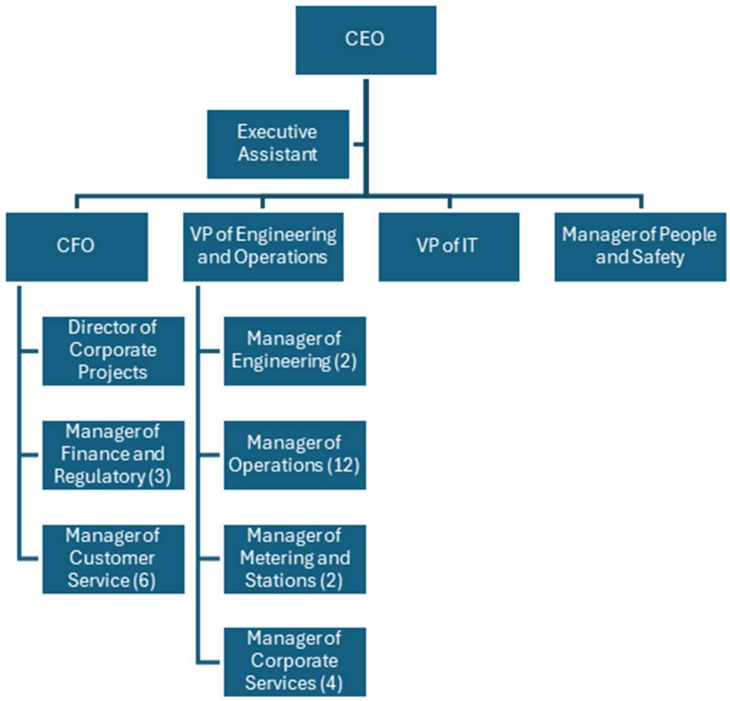


Figure 1-2 Corporate Organization Chart



There are no planned changes in corporate or operational structure, as well as no changes to its legal organization and control.

2.1.3.13 List of Specific Approvals Requested

As part of this Application FHI has requested the following approvals:

1. Approval of the 2025 Test Year rate base as proposed with FHI's average net book value of fixed assets and working capital allowance as set out in Exhibit 2 - Rate Base.

2. Approval of the Distribution System Plan as outlined in Attachment 2-2 in Exhibit 2.

3. Approval of the 2025 Test Year revenue requirement as proposed in Exhibit 6 - Calculation of Revenue Deficiency or Sufficiency as follows:

    a. Approval of the capital structure, cost of capital parameters, and deemed return on equity and debt proposed in Exhibit 5 - Cost of Capital and Capital Structure.

b. Approval of Test Year Operations, Maintenance and Administration expenses proposed in Exhibit 4 - Operating Expenses.

c. Approval of Test Year property taxes and payments in lieu of taxes (PILs) proposed in Exhibit 6 - Revenue Requirement and Revenue Deficiency / Sufficiency

d. Approval of the 2025 Test Year Service Revenue Requirement of $17,377,042 as proposed in Exhibit 6 - Calculation of Revenue Deficiency or Sufficiency.

e. Approval of the 2025 Revenue Offsets of $1,166,332 as proposed in Exhibit 6 – Revenue Requirement and Revenue Deficiency / Sufficiency.

f. Approval of the 2025 Test Year Base Revenue Requirement of $16,210,710 as proposed in Exhibit 6 - Calculation of Revenue Deficiency or Sufficiency.

4. Approval of Cost Allocation as filed in Exhibit 7 - Cost Allocation.

5. Approval of 2025 distribution rates and charges, effective January 1, 2025, as proposed in Attachment 8-5- 2025 Proposed Tariff of Rates and Charges found in Exhibit 8 - Rate Design.

6. Approval of updated Retail Transmission Service Rates (“RTSRs”), as identified in Exhibit 8 - Rate Design.

7. Approval of the Low Voltage rates as described in Exhibit 8.

8. Approval to continue to charge Wholesale Market (including CBR) and Rural Rate Protection Charges as directed by the Board.

9. Approval of revised total loss factor as described in Exhibit 8.

10. Approvals for disposition of Group 1 DVA accounts over one year as of December 31, 2023, of $(148,930) (including Account 1589), and associated class specific rate riders as set out in Exhibit 9 - Deferral and Variance Accounts.

11. Approvals for the disposition of Group 2 DVA accounts of $(420,349) over one year, as of December 31, 2023 with certain adjustments for forecasted amounts as of December 31, 2024 as set out in Exhibit 9 - Deferral and Variance Accounts.

12. Approval to continue the Specific Service Charges and Transformer Allowance.

13. Approval to rename ‘Income Tax Letter’ in Specific Service Charges to ‘Bill Copy Charge’ as described in Exhibit 8.

14. Approval to change ‘Service Call – Customer Owned Equipment’ and ‘Service Call – After Regular Hours’ from $30 and $165 respectively to be listed as Time and Materials as described in Exhibit 8.

15. Approval to use gross load billing for Retail Transmission Rates – Network and Connection charges for customers who have load displacement generation as detailed in Exhibit 8.

16. Approval to discontinue the use of Retail Cost Variance Accounts (RCVAs) 1518 and 1548.

17. Approval to continue to use Account 1592 – PILS and Tax Variance –Accelerated CCA for PILs impacts the phase out of the Accelerated CCA credit as described in Exhibit 9.

18. Other items or amounts that may be requested by FHI during this proceeding, and as may be granted by the OEB.

2.1.3.14 Certification of Evidence

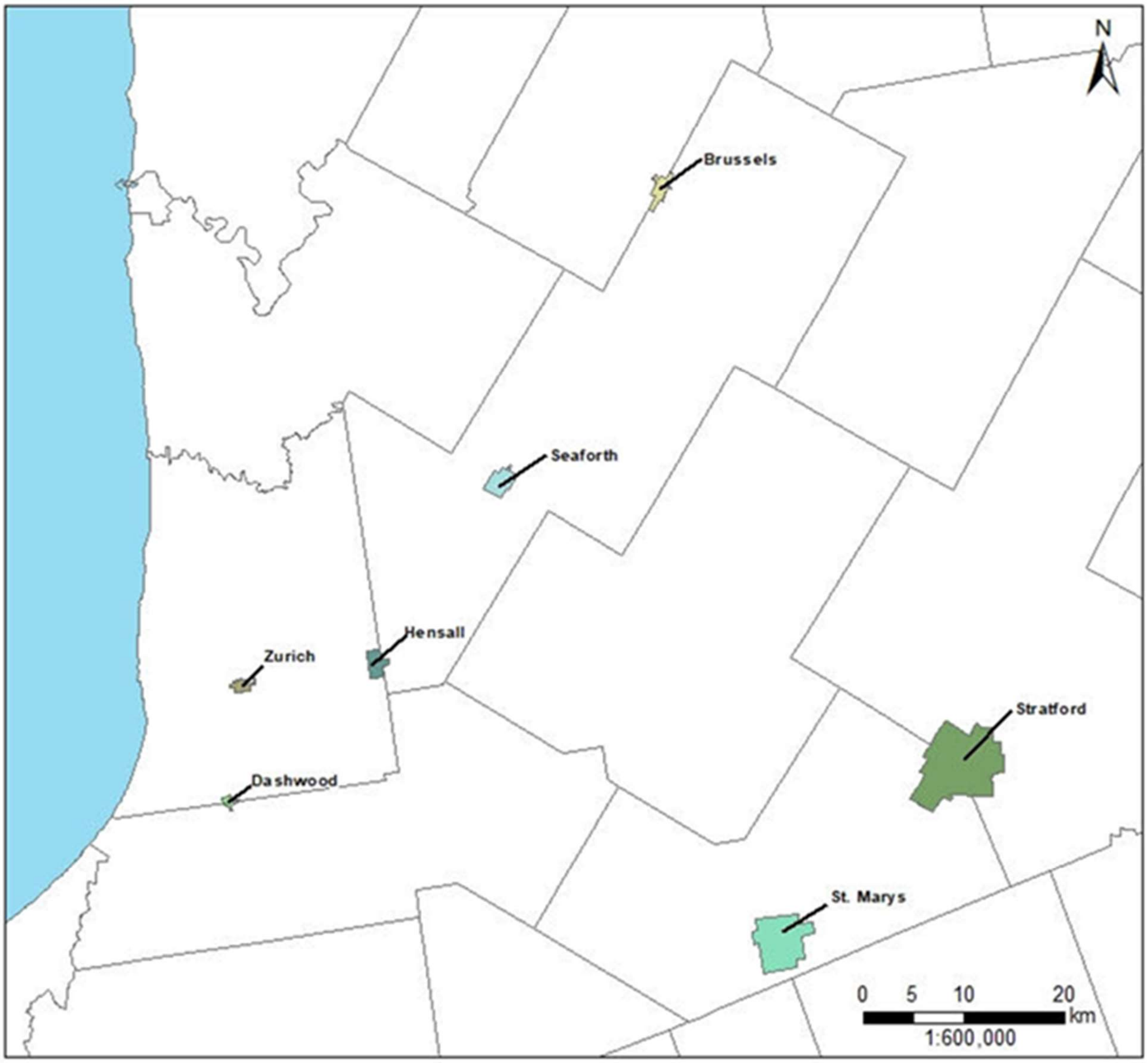
The Certification of Evidence signed by the President and CEO has been included in Attachment 1-20.

2.1.4 Distribution System Overview

FHI is comprised of seven geographically separate service territories (City of Stratford, Towns of St. Marys, Seaforth, Dashwood, Hensall, Zurich, and Brussels) and each service territory is bounded by Hydro One Networks Inc.

FHI is a Registered Market Participant for the purposes of settlement with the Independent Electricity System Operator. However, FHI is considered a partially "embedded" LDC because it received some of its electricity from Hydro One Networks Inc.'s low voltage distribution system for electricity supplied to customers in the towns of Brussels, Seaforth, Hensall, Zurich, and Dashwood.

Figure 1-3 Service Area Map



FHI has a service area of 43.42 km^2, which includes the City of Stratford, Town of St. Marys, and communities of Seaforth, Hensall, Zurich, Brussels, and Dashwood. The service area is all considered urban.

FHI's service area is within the temperate climate region of Southern Ontario. Throughout the year, the temperature typically varies from -10^{o}C during the winter to 25^{o}C in the summer. Both overhead (OH) and underground (UG) distribution systems are employed in FHI's service territory.

FHI is seeing moderate growth within its service area, with a need to invest in its systems to ensure it can maintain reliability and safety.

As of December 2023, FHI owns 587.4 km of primary conductors, of which 393 km is OH primary conductor and 194.4 km is UG primary cable. FHI operates using primary voltage levels of 2.4/4.16kV, 4.8/8.32kV, 8.0/13.8kV and 16.0/27.6kV for its distribution feeders. FHI owns two MS in the community of Seaforth and one TS in the City of Stratford.

FHI also has 5 dedicated 27.6kV feeds from HONI owned Stratford TS (68M2,68M3,68M4,68M5,68M8) and 4 dedicated 13.8 kV feeds from HONI owned St. Marys TS (9M1, 9M2, 9M3, 9M4).

FHI is also an embedded distributor to HONI in the following areas in its service territory:

- Hensall (fed from Seaforth TS 61M5 at 27.6kV)
- Brussels (fed from Brussels DS Feeder 3 at 8.32kV)
- Seaforth (Fed from Seaforth TS 61M3 at 27.6KV)
- Zurich (fed from Grand Bend East DS F1 at 27.6kV)
- Dashwood (fed from Grand Bend East DS F1 at 27.6kV)

FHI owns the following high voltage assets:

- 230/27.6kV Transmission Station MTS#1 (Stratford)

These assets have been deemed as distribution assets and FHI does not intend to change their status to transmission assets.

2.1.5 Customer Engagement

This Section details the activities FHI has taken with respect to Customer Engagement. Customer Engagement has always been important to the success of FHI. FHI recognizes its commitment to be of service to customers, employees and the community and its contribution to the success of each. FHI engages its customers through day-to-day contact and regular business activities. FHI has differentiated Customer Engagement into two categories: Ongoing Communications and Consultations Specific to the Application.

There are no new rate classes, changes to existing rate classes and changes in charges that would require specific customer engagement with the exception of those impacted by gross load billing. FHI communicated this change with the specific customers and provided personalized bill impacts to demonstrate the impact to their bill, which was immaterial. At the time of filing, impacted customers have not provided feedback.

2.1.5.1 On-Going Communications

MyFestivalHydro

FHI customers express interest in better understanding their electricity consumption and Time of Use (TOU) rates. Currently, London Hydro supports FHI's MyFestivalHydro, an online portal that provides customers with various options for viewing usage and billing information. This portal is also optimized for viewing on smartphones and tablets. Customers can view their monthly, daily, or hourly electricity usage and compare usage and TOU pricing between different periods of time. This tool allows customers to identify areas where they can reduce consumption or shift usage to a lower-priced TOU period and allows RPP customers to switch between TOU and Tiered pricing.

Through MyFestivalHydro, customers can also view or download any past bills, as well as usage data specific to a billing period. Based on February 2023 data, there are an average of 4,058 logins per month and 10,234 bill retrievals per month.

festivalhydro.com

FHI uses its website festivalhydro.com as a landing page to assist with customer inquiries. On the site, customers can learn about their bill and assistance programs, receive outage information, and use a variety of online forms. Through the online forms customers can request streetlight service, select their choice of pricing plan, open or close an account as well as several other account maintenance activities. This is an easy way for customers to make changes to their account when it is convenient for them.

Social Media

FHI is active on Facebook, X (Twitter) and LinkedIn. Posts are monitored to ensure customer questions receive timely and meaningful answers. Social media posts are made daily Monday-Friday, as well as on weekends and holidays during outages.

Social media has proven to be effective in reaching and communicating with FHI customers. Customers appreciate the ease of visiting FHI's social media channels for outage information. The friendly and timely responses to customer queries through social media have resulted in positive customer comments and reviews online.

FHI's social media plan focuses on educating consumers in the following content categories:

- General Customer Education: how to read hydro bill, TOU billing
- Crisis updates: storms, weather, outages, etc.
- IESO, OEB, EDA reposts
- News releases
- Job opportunities
- Energy conservation
- Safety messaging and education: downed wires, Ontario OneCall
- Highlight community involvement

• Giveaways

Community Outreach

FHI is proud to support and connect with the municipalities that it serves, and this is incorporated into its mission and vision statements. Through enhanced collaboration and relationship building FHI can seek to better understand the goals and needs of its customers and communities to ensure that their needs are met and that FHI is acting as a partner in their success. FHI participates in local municipal groups such as the City of Stratford Climate Change Working Group and the Economic Development Board (investStratford) to ensure that FHI is a partner to opportunities and developments within the community. FHI also gives back to local charities through fundraising and time donations for example: SoupsOn for Alzheimer's Society, Gloves for the Homeless through the Stratford Connection Centre, Tree Power Program, Personal Care Products for Optimism Place, United Way, LightsOn Stratford and the In Our Hands campaign benefiting Stratford General Hospital. FHI also held a community Open House when the first large section of the building renovation was completed in 2023. This allowed residents to tour the new space and ask questions about the investment. This event was well attended and received positive feedback.

Customer Satisfaction Surveys

Every two years, FHI engages Oraclepoll to conduct an engagement survey of its customers. The purpose of this survey process is to obtain customer input regarding their satisfaction with the services provided by FHI. The last survey was completed in Fall of 2022.

FHI's strong customer focus and commitment to reliability have resulted in a high level of customer satisfaction at 93% in 2022. The most recent report is attached as Attachment 1-8 – Oraclepoll Customer Satisfaction Survey Report, 2022.

2.1.5.2 Consultations Specific to the Application

In response to the Board's Filing Requirements to engage customers on the specific proposals contained in this Application, in April 2023 FHI commissioned Brickworks Communications to conduct engagement surveys of its customers. The purpose of this survey process was to obtain customer input regarding FHI's business plans for the period 2025 to 2029, and to gather information from them about service and cost. FHI has used the results of the customer engagement to shape the business plan, budget for 2025, and long-term plans for the forecast period for this Application.

Complete copies of the Brickworks Communication Reports are included in Attachment 1-10.

FHI determined that customer engagement would be most effective to be completed in two separate phases. Phase one would be a brief online survey to gather high level insights, information, and feedback from its customers prior to completing its business plan. FHI would then use the business plan to shape the 2025 budget and forecast period. The second phase would be another survey completed both online and telephone to ensure that FHI 'got it right' when developing its business plan using the high-level needs and preferences. FHI also used this opportunity to provide more education to customers on the distribution system, FHI's role in the system and to clarify areas where the first survey required more specific opinions.

The first phase of consultation included an online survey that was open to all customer classes from May 18 to June 2, 2023. FHI promoted the survey with an e-blast to its customer base as well as notifications on its website and social media.

The survey results identified that the number one customer priority is to have "Reliable" and "Safe" electricity, followed by prioritizing aesthetics over cost. FHI used the results to assist in preparing the business plan. The remainder of the results can be seen in Attachment 1-10.

Phase two of the customer consultation was a combination of an online survey and a telephone survey which ran from November 22nd to December 11th, 2023. This survey was done after initial budgets were created with detailed plans incorporated. FHI focused on questions that were customer facing. The results between the online survey and telephone survey yielded very similar results, which can be seen in Attachment 1-10.

Some key themes that were noted in the survey are that customers want FHI to invest more money IN emerging technologies and environmentally conscious options (or both) even it if is at an increased cost (89-92% agreed). There was also support for more frequent tree trimming so that fewer power outages occur. Lastly, it was projected at the time that the rate increase would be approximately $6.75 and 82-83% of customers support the increase. Included in the Business Plan in Attachment 1-11 is a description of the changes that were made to the budget after the customer engagement.

2.1.6 Performance Measurement

2.1.6.1 Scorecard

In connection with the RRFE outcomes, FHI posted its 2022 scorecard and MD&A on its website, which is included as Attachment 1-16.

Each of the scorecard metrics are discussed in the Business Plan in Attachment 1-11.

2.1.6.2 Efficiency Assessment

In Table 1-14 FHI has included its PEG Efficiency Assessment Projection.

Table 1-14 Efficiency Assessment Projection

Cost Benchmarking Summary	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Actual Total Cost	13,139,203	13,434,051	12,917,513	14,068,956	13,890,203	13,614,678	13,447,473	14,971,727	17,426,124	18,562,561	20,536,646
Predicted Total Cost	11,424,611	11,745,757	11,828,490	12,622,731	13,089,038	13,393,349	13,914,381	15,331,898	17,383,419	18,439,115	19,793,799
Difference	1,714,592	1,688,294	1,089,023	1,446,225	801,165	221,329	- 466,907	- 360,171	42,705	123,446	742,847
Percentage Difference (Cost Performance)	14.0%	13.4%	8.8%	10.8%	5.9%	1.6%	-3.4%	-2.4%	0.2%	0.7%	3.7%
Three-year Average Performance			12.1%	11.0%	8.5%	6.1%	1.4%	-1.4%	-1.8%	-0.5%	1.5%
Stretch Factor Cohort											
Annual Result	4	4	4	4	3	3	3	3	3	3	3
Three-Year Average			4	4	3.7	3.3	3	3	3	3	3
IRM Increase		1.65%	1.45%	0.75%	1.05%	1.55%	1.90%	3.00%	3.10%	4.20%	N/A

Based on the inputs in this Application, FHI is projected to remain in Group 3. In 2019, FHI moved from Group 4 to Group 3, an indicator of efficiency improvement, and actively monitors its performance and cost spending to remain in Group 3. The efficiency variance is considered during the budgeting process and is also provided to the Board of Directors as part of its scorecard. The calculation of projected PEG results in the Test Year was reviewed prior to finalization of the Business Plan and Test Year Budget as FHI is focused on remaining in Group 3.

2.1.6.3 Activity and Program-Based Benchmarking (APB)

The following examines the results of the OEB's Activity and Program-Based Benchmarking (APB) study, issued on May 4, 2022. As shown in Table 1-15, based on the average costs from 2018 to 2022, for each of the 10 cost activities examined, FHI is below the average in six of the 10 categories. FHI has discussed its results and performance on the measures where it is above the average below. FHI has also provided estimates for 2023-2025 in Table 1-16.

Table 1-15 APB Results and Analysis

Activity	Measure	FHI Average Unit Cost (2018-2022)	Distributor Average Unit Cost (2018-2022)	Above/Below Average
Billing O&M	$/Customer	28.31	35.82	Below
Metering O&M	$/Customer	28.29	19.43	Above
Vegetation O&M	$/Pole	25.76	36.62	Below
Lines O&M	$/Primary Circuit km	4,796.47	1,796.81	Above
Stations O&M	$/MVA	539.70	1,237.80	Below
Poles, Towers O&M	$/Pole	9.09	10.83	Below
Stations CAPEX	$/MVA	6,704.60	3,956.00	Above
Poles, Towers CAPEX	$/Poles Installed	6,050.00	9,472.00	Below
Line Transformers CAPEX	$/Line Transformer Installed	7,606.30	10,450.00	Below
Meters CAPEX	$/Customer	12.75	11.80	Above

Table 1-16 APB Projections 2023-2025

Activity	Measure	2023	2024 Projection	2025 Projection
Billing O&M	$/Customer	31.40	36.87	40.64
Metering O&M	$/Customer	27.81	30.01	32.85
Vegetation O&M	$/Pole	29.97	29.17	34.72
Lines O&M	$/Primary Circuit km	4,597.12	5,287.46	5,512.25
Stations O&M	$/MVA	295.00	-	200.00
Poles, Towers O&M	$/Pole	12.83	11.62	11.62
Stations CAPEX	$/MVA	-	-	-
Poles, Towers CAPEX	$/Poles Installed	6,937.61	7,326.39	7,613.64
Line Transformers CAPEX	$/Line Transformer Installed	8,647.08	8,469.39	8,750.00
Meters CAPEX	$/Customer	19.23	17.53	61.80

Metering O&M: While FHI doesn't have insight into what others are doing in this space, FHI's cost has remained level over the years. The main contributors to the measure being high that are outside industry norms are that every year FHI must spend money to send back meters for Return Material Authorizations (RMAs), approximately 600 each year in this 5-year average. This incurs cost on FHI not just to send the meter back and pay for the repair, but also the time and labour to go out and exchange the meter itself. FHI also has hundreds of non-communicating meters still in the field that it must manually read every single month which costs FHI approximately $20-$30k each year (adds $1/customer). The new AMI 2.0 system, once fully implemented, is expected to decrease both costs going forward.

Forecasted unit costs for this category going forward are expected to increase during FHI's transition to an AMI 2.0 system. There will be temporary costs during the transition, such as dual Head End Systems, until the transition is complete. Some of these temporary cost increases are expected to be offset by a reduction in manual meter reads as newer meters are installed. The new AMI 2.0 system, once fully implemented, is expected to decrease both costs going forward.

Lines O&M: This account has all of FHI's vehicles, stores and additional linespersons labour costs, allocated depreciation, and service centre building costs. This is an area where FHI believes that it is likely to include more costs than other LDCs. Due to the results of the APB, FHI is planning to investigate the costs within this group to ensure that it is properly allocating these costs and will make appropriate adjustments on a go-forward basis.

Forecasted unit costs for this category going forward are expected to increase at inflationary rates, as no new programs are contemplated in future years. However, as noted above, FHI plans to investigate the reasoning behind why this category is significantly higher than other LDC's and ensure that costs are being properly allocated.

Stations CAPEX: This calculation considers the total MVA for all Distribution stations, of which FHI only have two. Due to the relatively small capacity of FHI's two Distribution Stations (10 MVA) combined, any single project cost within the period can have a large impact on this benchmark, and conversely, no projects in the forecast period could put FHI's measure well below the comparator average. FHI had one project in one of the years within the five-year forecast where it completed urgent ground grid upgrades to both stations based on a third-party assessment on the condition of the substations. The ground grids at both were deemed a safety hazard. This is the only substantial capital investment in the five-year period, but it is the reason for the FHI measure scoring above the average.

Forecasted unit costs for this category are $0 as FHI is planning the removal of both Stations as part of a voltage conversion program, and as such is not planning any capital investments.

Meters CAPEX: FHI had two years out of the five-year period where costs were abnormally higher. Firstly, a large quantity of reverifications of meters were required for a seal extension, which is a requirement of Measurement Canada for continued operation of these assets. Secondly, FHI was notified by its AMI provider that the residential meter product that FHI purchases is being retired/discontinued from the market. In response to this FHI purchased several meters to ensure sufficient supply of this product was available to ensure customer metering could be uninterrupted until FHI determined its next steps to address the issue with a longer-term solution.

Forecasted unit costs are higher than historical, with a significant increase in 2025, which is a result of FHI's planned AMI 2.0 deployment. Historically, costs in this category are for new customer connections, or to maintain regulatory compliance. However, beginning in 2023, based on the condition of FHI's meter assets, increasing maintenance costs, and procurement issues, FHI made the strategic decision to examine their options. The end result was to complete a re-deployment of the AMI system. This impacts this category, as this project will be a mass deployment to install meters and corresponding hardware for both new and existing customers. Once this multi-year project is completed, FHI expects the amount of work associated with this category to return to historical levels.

FHI is in the early stages of using the APB results to drive decision-making and assess efficiencies. FHI plans to refine its accounting practices, specifically as it moves to a new ERP system, to better track expenses measured by APB Benchmarking. This will improve the quality of the results and comparability to other distributors as well will provide valuable insights to FHI.

2.1.7 Facilitating Innovation

As part of its commitment to continuous improvement, FHI monitors the state of technological advancements made within the utility sector. Projects and equipment involving system automation, EV uptake, battery storage and other non-wires alternatives (NWAs) are monitored, and where appropriate, considered as part of FHI's planning process. Where it is financially responsible to do so, these technologies may be incorporated into the renewal and upgrade projects to meet the current and future needs of customers, improve operational effectiveness, as well, support the integration of renewables and smart grid technologies.

FHI undertakes innovative projects which are intended to help reduce costs, improve the safe and reliable distribution of electricity, create efficient and effective work environments for staff, and/or allows FHI to provide beneficial services to customers. Often these projects benefit more than one of these categories. Examples of innovation historically, and with this Application include:

Beneficial Services to Customers:

- **Online Forms** – FHI provides most customer service-related changes/updates using online forms which are easy for customers to download, fill out and submit. This allows customers to gather all the required information on their time and assists with decreased communication errors between customers and CSRs.
- **Green Button** – In 2023, FHI implemented Green Button. While this program is mandated by the Ontario government, FHI considers it innovative in that it provides benefits to customers that they value. The program provides households and businesses access to their electricity data or authorizes the automatic, secure transfer of their data from their utility to applications or third parties, allowing for better insight and management of energy use.
- **New Customer Information System (CIS)** – In 2024, FHI implemented a new CIS. This change was required because the previous system became obsolete and was no longer supported by the vendor as FHI was the last remaining Canadian customer.

The new CIS allows for easy implementation and configuration of regulatory changes and ensures that FHI is compliant with all current requirements. There will also be streamlined communications to customers related to bill changes or delinquency processes. This new system also allows for better use of staff time by limiting manual processes.

Safe and Reliable Distribution of Electricity:

- **Outage Management System (OMS)** – FHI began its implementation of an OMS during the historical period with the goal of providing more visibility into events happening on the distribution grid that will proactively and autonomously engage with customers. This project required the integration of several data sources (e.g., customer information systems, advance metering infrastructure, geographic information systems, SCADA) to allow for full implementation of the objectives. This project also provided FHI with better engineering analysis capabilities, such as: system studies, DER/Connection Impact Assessments, fault analysis and load forecasting.
- **Distributed Transformer Monitoring** – FHI's SmartMAP software allows for the transformer monitoring of each distribution transformer installed in the field. This provides information such as: energy theft detection, EV detection, transformer loading, and distributed generation, assisting with load management. For example, as the take-up on electric vehicles increases, this software detects potential locations where EV's have been installed based on loading history and helps FHI to assess the impact and ensure it has the flexibility to meet customer needs.
- **Voltage Conversion** – FHI is planning to undertake a voltage conversion project in their final 4kV community, continuing beyond the forecast period with completion by 2033. This project is expected to bring benefits in several ways. Mainly, the removal of the final two distribution stations, which are at or approaching their end of life, and allow FHI to avoid the need to invest significant capital to replace and upgrade the transformers and switchgear at both stations. Also, these remaining circuits once transferred over from 4kV to 27.6kV, will better position FHI to accommodate larger

customer demand and DER's as these feeders have an enhanced capacity. Finally, there will inherently be a reduction in electrical losses by retiring two 4kV distribution stations and the move to a higher distribution voltage.

- **Distribution Automation and Modernization -** FHI plans to automate more of its network over the forecast period, which will also enable FHI to expand its self-healing network, allowing the distribution system to automatically re-route power without manual intervention. This is a fundamental concept of a self-healing network, which helps to reduce the size and duration of outages.
- **AMI 2.0** - FHI plans to replace its legacy AMI 1.0 installation with an AMI 2.0 redeployment. This will provide FHI with more reliable communications for billing, and infrastructure that will provide for current and future needs over the systems expected service life. This investment will also provide access to information that is not currently available with AMI 1.0 infrastructure, such as enhanced power quality monitoring and grid edge computing for distributed intelligence, opportunities to better support the integration of renewables and EV's, as well as give customers better access to energy data and understanding their consumption.

Process/Operational Improvement

- **GIS Utility Network (UN) Migration** – FHI's existing GIS is based on ESRI's Geometric Network technology, which is approximately twenty-five years old, and will no longer be supported by the vendor in March 2026 as they move exclusively to a UN platform, which is an industry specific platform for electric utilities and includes many enhancements on data storage, configuration, and analysis. As a result, FHI is planning to undertake a GIS UN Migration project in 2024, wherein all FHI's existing asset information and integrations will be migrated to the new platform.
- **Enterprise Resource Planning System (ERP)** – In 2024 and 2025, FHI is implementing a new ERP system which will allow for substantial improvements of efficiency and effectiveness throughout the organization. This system includes most aspects of the business including finance (general ledger, accounts payable and receivables), payroll and human resources, budgeting, fixed assets, estimating, job

costing, work order, purchasing and inventory and asset management. Many of these tasks were previously manual or significantly dated which limited the ability for thorough analysis and forward planning opportunities.

2.1.8 Financial Information

2.1.8.1 Audited Financial Statements

FHI's 2023 and 2022 audited financial statements, with 2021 historical information for comparison, have been included as Attachment 1-12 and Attachment 1-13 respectively. FHI uses International Financial Reporting Standards ("IFRS") for general purpose financial statements. For ratemaking purposes, Modified International Financial Reporting Standards ("MIFRS") were adopted as part of FHI's last Cost of Service Application (EB-2014-0073). In 2013 FHI made the necessary changes to its accounting practices to comply with the requirements of MIFRS, including changes to its depreciation rates and removing overhead expenses from capital. FHI's financial statements continued to be reported under CGAAP (while incorporating these MIFRS changes) until IFRS was formally adopted by the company effective January 1, 2015, for external financial reporting. At the time of adopting IFRS there were no changes required to FHI's accounting practices as all necessary changes were made in 2013, however the scope of audit increased as did the financial note disclosure accompanying FHI's financial statements.

FHI has also included its 2022 Annual Report in Attachment 1-18. FHI does not have any Management discussion and analysis (MD&A), rating agency reports or any other public reports to file.

FHI has not had any change to its tax status.

2.1.8.2 Existing Accounting Orders

FHI does not currently have any distributor specific accounting orders.

2.1.8.3 Uniform System of Accounts (USoA)

FHI follows the USoA for accounting purposes, although as noted in section 2.1.6.3 Activity and Program-Based Benchmarking (APB), FHI is working to improve the comparability of expenses with other distributors. This will be reviewed as part of the transition to a new ERP system in 2025.

2.1.8.4 Confirmation of Accounting Treatment for Non-Distribution Businesses

FHI records the revenue and expenses for non-utility businesses to OEB Account 4375 'Revenues from Non-Rate-Regulated Utility Operations' and to OEB Account 4380 'Expenses of Non-Rate-Regulated Utility Operations'. Any non-utility capital assets are recorded in OEB Account 2075 'Non-Rate-Regulated Utility Property Owned' and OEB Account 2180 'Accumulated Depreciation of Non-Rate-Regulated Utility Property'.

All of these OEB accounts are excluded for rate making purposes. As such, no amounts are included in the 2025 Test Year.

The nature of FHI's non-utility related businesses falls into three categories:

Water Billing and Collecting, Streetlight Installation and Maintenance, and Renewable Generation.

Water Billing and Collecting

All amounts related to the water billing, meter reading and collecting for the City of Stratford and St. Marys revenues and expenses are recorded in Accounts 4375 and 4380, respectively. All expenses and a markup in accordance with the Affiliate Relationship Code are covered by the revenue that is generated.

Streetlight Installation and Maintenance

Streetlight installation and maintenance work is completed by FHI for the City of Stratford. Similar to the water billing noted above, all costs as well as a markup is billed to the City of Stratford. Minimal streetlight installation is also completed in other communities when transferring the assets to rebuilt pole lines. All revenues and expenses are recorded in Accounts 4375 and 4380.

Renewable Generation

FHI has invested in three solar renewable generation projects. The capital assets are recorded in OEB Account 2075, and the related revenue and expenses (including amortization) are recorded in OEB Accounts 4375 and 4380.

2.1.9 Distributor Consolidation

FHI has not acquired or amalgamated with another distributor since its last rebasing Application.

FHI's strategic goals include Creating Scale in the Utility Space. As an alternative to an acquisition or amalgamation, FHI recognizes the benefits and importance of scale in this sector and has focused on doing this through shared services and collaboration. FHI collaborates extensively with other Ontario distributors to improve efficiency and mitigate costs. Some examples of this collaboration include:

- FHI uses the control room of London Hydro for its SCADA monitoring, switching and hold-offs. This is significantly less expensive than if FHI were to have its own control room.

- FHI also partners with London Hydro for its customer portal and green button products which has reduced the cost and effort to implement this internally.

- FHI receives metering services from ERTH Power including wholesale metering services, meter reverifications and 3-phase metering work. Skilled labour in this area can be difficult to find, so outsourcing this work allows for service continuity.

- In 2023, FHI pursued a shared resource with ERTH Power to provide regulatory assistance to help stay on top of regulatory policies and requirements as well as assist in preparing rate applications and other filing requirements.

- FHI and Enova Power have a reciprocal agreement for disaster recovery to protect data and information in case of an emergency.

- FHI is also a part of several industry groups including the Electricity Distributor's Association (EDA), Utilities Standards Forum (USF) and other informal communications to help with the sharing of ideas, information and best practices.

FHI will continue to look for opportunities to leverage internal offerings, partner with other LDCs on innovative projects and shared services where practical.

2.1.10 Impacts of Covid-19

On March 11, 2020, the World Health Organization declared the Covid-19 outbreak a global pandemic. Ontario declared a state of emergency on Tuesday, March 17th. This pandemic had a significant impact on all FHI's departments and overall business continuity plan. In March 2020, FHI undertook several steps in response to Covid-19 including setting up employees in a remote working environment for those who were able. FHI enacted a multitude of business continuity plans in order to protect the safety of its workers and to continue to operate a safe and reliable distribution system. However, FHI's operations and spending plans had to be adjusted to accommodate the changing landscape of the pandemic.

FHI noted incremental operating costs during Covid-19 related to additional cleaning costs, safety materials, a one-person per vehicle policy increasing fuel and fleet maintenance costs, and IT related expenses for remote work capabilities. OM&A was also impacted by regulatory and billing changes mandated by the OEB. The OEB enacted emergency TOU pricing a few different times during the Covid-19 pandemic requiring multiple billing updates not accounted for. The OEB also made available additional LEAP funding to customers who qualified under the OEB's new guidance. This required the processing of many applications to determine if the customer qualified for additional LEAP funding. However, these incremental costs were offset by decreases in expenses including travel, training, and unrelated to Covid-19 vacancies within the Executive Team which is discussed further in Exhibit 4. As a result, FHI was successful in managing incremental Covid-19 related expenses within its current level of operating expenses and is not seeking recovery of any incremental expenses.

While there were many changes to work practices and operational procedures, there are limited sustained operational cost savings as training and travel has returned to normal levels.

From a capital perspective, the majority of capital work continued through the pandemic with some projects deferred to the following year compared to plan. This is described in the DSP in Attachment 2-2. The main impacts that are still being seen from the pandemic are supply constraints, rapidly increasing pricing, inflationary increases, interest rate increases, and labour shortages. All of these challenges have been discussed in the Business Plan in Attachment 1-11. FHI continues to address these issues each day with the close monitoring of its budget, the health and safety of its employees and the longer-term cash flow forecasting as presented in its budget.

Attachment 1 – 1

Required OEB Appendices

Ontario Energy Board

Chapter 2 Appendices
Filing Requirements for Electricity Distribution Rate Applications

Version 1.0 (2025)

Utility Name	Festival Hydro Inc.
Assigned EB Number	EB-2024-0023
Name of Contact and Title	Alyson Conrad, Chief Financial Officer
Phone Number	519-271-4700 ext. 221
Email Address	aconrad@festivalhydro.com
Test Year	2025
Bridge Year	2024
Last Rebasing Year	2015
Identify the accounting standard used for the test year	MIFRS
Did Festival Hydro Inc. update its depreciation and capitalization policies?	Yes
If "yes" to cell E34, were the changes in policies reflected in a prior rebasing application?	Yes
When did Festival Hydro Inc. update its actual depreciation and capitalization policies?	**January 1** **2013**
Identify the year the applicant adopted IFRS for financial reporting purposes	2014
Is Festival Hydro Inc. applying for cost recovery for the test and/or future year(s) for Green Energy initiatives?	No
Is Festival Hydro Inc. an embedded distributor?	Partial

<u>Notes</u>

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.

File Number:	EB-2024-0023
Exhibit:	1
Tab:	
Schedule:	
Page:	26-28
Date:	2024-04-26

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Festival Hydro Inc. is seeking the following approvals in this application:

1		Approval of the 2025 Test Year rate base as proposed with FHI's average net book value of fixed assets and working capital allowance as set out in Exhibit 2 - Rate Base.
2		Approval of the Distribution System Plan as outlined in Attachment 2-2 in Exhibit 2.
3		Approval of the 2025 Test Year revenue requirement as proposed in Exhibit 6 - Calculation of Revenue Deficiency or Sufficiency as follows:
3	a	Approval of the capital structure, cost of capital parameters, and deemed return on equity and debt proposed in Exhibit 5 - Cost of Capital and Capital Structure.
3	b	Approval of Test Year Operations, Maintenance and Administration expenses proposed in Exhibit 4 - Operating Expenses.
3	c	Approval of Test Year property taxes and payments in lieu of taxes (PILs) proposed in Exhibit 6 - Revenue Requirement and Revenue Deficiency / Sufficiency

3	d	Approval of the 2025 Test Year Service Revenue Requirement of $17,248,582 as proposed in Exhibit 6 - Calculation of Revenue Deficiency or Sufficiency.
3	e	Approval of the 2025 Revenue Offsets of $1,291,332 as proposed in Exhibit 6 – Revenue Requirement and Revenue Deficiency / Sufficiency.
3	f	Approval of the 2025 Test Year Base Revenue Requirement of $15,957,250 as proposed in Exhibit 6 - Calculation of Revenue Deficiency or Sufficiency.
4		Approval of Cost Allocation as filed in Exhibit 7 - Cost Allocation.
5		Approval of 2025 distribution rates and charges, effective January 1, 2025, as proposed in Attachment 8-5- 2025 Proposed Tariff of Rates and Charges found in Exhibit 8 - Rate Design.
6		Approval of updated Retail Transmission Service Rates (“RTSRs”), as identified in Exhibit 8 - Rate Design.
7		Approval of the Low Voltage rates as described in Exhibit 8.
8		Approval to continue to charge Wholesale Market (including CBR) and Rural Rate Protection Charges as directed by the Board.
9		Approval of revised total loss factor as described in Exhibit 8.

10		Approvals for disposition of Group 1 DVA accounts over one year as of December 31, 2023, of $(148,930) (including Account 1589), and associated class specific rate riders as set out in Exhibit 9 - Deferral and Variance Accounts.
11		Approvals for the disposition of Group 2 DVA accounts of $(420,349) over one year, as of December 31, 2023 with certain adjustments for forecasted amounts as of December 31, 2024 as set out in Exhibit 9 - Deferral and Variance Accounts.
12		Approval to continue the Specific Service Charges and Transformer Allowance.

Attachment 1 – 2

Board Roles and Responsibilities

b. Roles & Responsibilities

i. **Board Leadership**

The board is responsible for creating and managing a governance structure, for holding itself accountable, and for ensuring effective board collaboration for the benefit of the organization and its owners.

The board commits itself to ethical, efficient, and lawful conduct. Board members will function in an ethical manner, contribute to the work of the board, support the decisions of the board, and respect the confidentiality of privileged information.

The board will speak with one voice. All board members will support all board decisions outside of board meetings.

Board members will make every effort to attend and participate in all meetings and be properly prepared for board deliberation.

Board members will treat each other with respect and professionalism. When differences of opinion exist, the commitment will be to challenge the issues but never attack or defame the person.

Board members may not exercise individual authority over the organization, management, staff, or clients except as explicitly directed by the board through a duly passed motion. Board members will not judge the performance of personnel outside of the official board process.

The board will annually monitor its own effectiveness and take actions to excel in its role.

The board may conduct an assessment of each board member's individual performance.

ii. Board Officers

The board will maintain clear descriptions of the duties of each officer. Each officer will serve the board and follow the board's direction.

1. **Chair**

   The Chair of the board will ensure that the board behaves consistently with its own rules and those legitimately imposed upon it from outside the organization.

   The Chair of the board will preside at board meetings. He/she may appoint an alternate to serve in this capacity as needed.

   The Chair of the board will prepare the draft agenda in consultation with Vice Chair and the CEO.

   The authority of the Chair between board meetings is only to make reasonable interpretations of board policy on behalf of the board.

   The Chair of the board will work within board policy when making any necessary decisions between board meetings, except where the board specifically delegates portions of its authority to the Chair.

   The Chair will confer with the Vice-Chair to ensure that the Vice-Chair is familiar with and informed about the issues well enough to assist and replace the Chair if necessary.

   The Chair of the board will be the public spokesperson for the board, unless someone else is appointed by the board.

   The Chair has no authority acting alone to supervise or direct the CEO without the approval of the board.

   The Chair should have served as a committee chair and board vice chair for a minimum of one year.

   The Chair shall be an independent Director.

2. **Vice-Chair**

   The Vice-Chair of the board will perform the functions of the Chair in the Chair's absence.

   The Vice-Chair should have served as a committee chair for a minimum of one year.

   The Vice-Chair should be an independent Director.

3. **Secretary (Corporate Secretary)**

The Secretary will be appointed at the 1st meeting of the new term of Directors and Officers.

The Secretary should be a member of the Board. Consideration should be given that the CEO be deemed a non-voting member of the Board and hold the position of Secretary.

The primary role of the Secretary of the board is to ensure appropriate written documentation of the board's decisions and general meeting decisions.

The Secretary will ensure that the minutes are prepared and circulated following a board meeting.

The Secretary will ensure that the policy manual is updated following each board meeting.

The Secretary will ensure that all documentation of board business is up to date and in compliance with legal obligations.

iii. Board Committees

Board committees are to help the board do its job, not to help staff do its jobs. Committees ordinarily will assist the board by preparing policy alternatives and implications for board deliberation.

Board committees may not speak or act for the board except when formally given such authority for specific and time-limited purposes.

Committee reports to the board will be in writing and made available so that they can be circulated for all board members to receive them in adequate advance prior to the board meeting at which related matters will be discussed.

Committee reports will summarize the information researched by the committee. When various options have been considered by the committee, the report will indicate the pros and cons of each option. The committee will make a recommendation to the board.

The Committee Chair should have served on the committee for a minimum of one year.

The Chair should be an independent Director.

The Board may establish committees of the Board at the Board's discretion. The following **are the standing** committees.

Audit Committee - Terms of Reference as posted in appendix.
Risk Committee – Terms of Reference as posted in appendix
Human Resource Committee - Terms of Reference as posted in appendix.
Executive Committee - Terms of Reference as posted in appendix.

iv. Director Terms

An independent director is appointed to serve up to twelve (12) years on the board. The term lengths are generally a four-year term, and the start and end date of the term year will coincide with the City of Stratford's council term beginning on December 1st and ending on November 30th of the following year.

All council members are appointed in the same year and serve terms of 4 years and the shareholder shall determine the maximum number of years a councilor may serve on the board. The BOD should strive to not appoint more than 2 independent members in the same year to ensure maximum continuity on the board.

c. Ethics

Board members will operate in an ethical and legal manner.

Board members will adhere to policies concerning fraud, dishonest conduct, discrimination, and sexual harassment as established by the organization.

All employees have the opportunity to exercise the Whistle Blower Policy and to report any activity or suspected activity of which he or she may have knowledge which appears to be prohibited by Festival Hydro's Code of Conduct.

d. Organizational Planning

The board will ensure the organization has a current strategic plan at all times.

The board will engage in a full strategic planning process every 4 years.

The board will review the strategic plan and set annual strategic goals every year via the appropriate committee.

The board will approve the annual budget in the year prior to the beginning of the fiscal year. The board will also have the authority to approve a multi-year budget if required.

e. Organizational Results

The board will assess the organization's results within the context of its business environment.

The board will regularly allow for whole board reflection on operational performance. On an ongoing basis the board will compare organizational results against goals.

Every year the board will compare the organization's results to available bench-marking data for similar organizations as presented in Festival Hydro Key Performance Indicators.

The board will consider the reasons for the organization's recent results and identify lessons learned.

f. Business Context

The board will reflect on the business environment and consider implications to the organization.

On an annual basis board should reflect on fiduciary, strategic, generative and operation activities.

Attachment 1 – 3

Audit Committee Terms of Reference

a. Audit Committee Terms of Reference

The Audit Committee is delegated as responsible for all financial and auditing aspects of the Corporation. Specifically, in its advisory role to the board of directors, it has within its mandate the consideration of the following matters:

- Review annual operating and capital budgets and make recommendations for approval to Board.
- Review quarterly operating results (revenues, expenditures, cash flow, etc.) comparing with operating budget and prior year actuals.
- Review capital expenditures and compare with capital budget.
- Review financial data related to business acquisitions/arrangements and make appropriate recommendations to Board.
- Review of policies and procedures such as Travel, Purchasing Tenders, etc. as required relating to financial matters.
- Review the external auditors audit plan and audit findings report pertaining to the annual financial audits.
- Review audited financial statements for board approval. Prepare and /or review audit policies and procedures.
- Review tenders and/or contracts for board approval.
- Review leases and financial agreements and guarantees, etc.
- Review significant non-budgeted capital and operating expenditures for recommendation to the board.
- Review and act upon other financial matters as required.
- Suggest criteria for financial ratio's, such as Debt to Equity, Current Ratio, Cash Position.
- Review loan covenants, i.e., liquidity ratios and debt to equity, to ensure compliance.
- Review RFPs for external auditing services and banking services for board approval.

The Committee meets upon the direction of its Chair, depending on the need for such meetings and reports to the Board of Directors.

As a standing agenda matter, the Committee receives a report from the Executive Leadership Team on any of the above-noted areas which require discussion at each meeting.

Attachment 1 – 4

Risk Management Committee

Terms of Reference

c. Risk Management Committee Terms of Reference

The ***Risk Management Committee*** is responsible for matters related to all aspects of the Corporation's operations and facilities. Specifically, in its advisory role to the board of directors, it has within its mandate the consideration of the following matters:

- Establish and Review the Enterprise Risk Assessment for the corporation.
- Establish and Review the Risk Statement for the corporation.
- Review Environmental compliance and management, including development and implementation of policies and procedures.
- Insurance and related liability issues for the Corporation, its employees, officers, and directors.
- Risk issues in relation to properties and operation of activities.
- Legal actions, orders or other actual or potential liabilities to the Corporation.
- Incidents, emergencies, or other events which may generate risk.
- Review the Cybersecurity Framework.
- Other matters involving risk to the Corporation as required.

The Committee meets at least three (3) times a year to review and assess the risk mitigation strategy being implemented by Executive Leadership.

As a standing agenda matter, the committee receives a report from the Executive Leadership Team on any of the above-noted areas which require discussion at each meeting.

d. Executive Committee – is responsible for:

- Board renewal with recommendation to the Shareholder.
- Board evaluation on an annual basis.
- Company and Board Policy direction.
- Shareholder relations.

Attachment 1 – 5

HR Committee Terms of Reference

b. Human Resources Committee Terms of Reference

Human Resources is delegated as responsible for all Executive Leadership, Union Contract and Stakeholder communication. Specifically, in its advisory role to the board of directors, it has within its mandate the consideration of the following matters:

- Periodic evaluation of CEO and reporting of findings and the CEO to conduct periodic evaluation of other executive management and reporting of findings.
- The hiring process and arranging of interviews of potential candidates for the position of CEO.
- The Board Chair and the HR Committee Chair shall participate in and assist the CEO in the hiring process for all senior executive positions and the CEO will keep the board informed of all progress; however, the CEO remains the hiring authority for all direct reports to the CEO.
- Consultation on the executive compensation framework for the organization and recommendation on an executive compensation framework to the board for approval.
- Approval of guidelines for Union Negotiations and other non-union staff.
- Policies and procedures regarding communications with customers.
- Personnel policy review as required.
- Health and safety compliance and management, including development and implementation of policies and procedures.
- Regulatory and statutory compliance in regard to other areas of risk relating to Human Resources, including human rights, employment/labour relations and privacy legislation etc.; as well as compliance with the Ontario Energy Board's Best Practices in Utility Governance.
- Review and recommendation of the CEO compensation and pay for performance incentives for recommendation to the board for approval.
- Administration and completion of the annual Board Effectiveness Survey.

The committee meets upon the direction of its Chair, depending on the need for such meetings and reports to the Board of Directors.

Attachment 1 – 6

Code of Conduct

Purpose:
A guide for Board of Directors and Employees on how to conduct themselves with regards to Festival Hydro Inc.

Scope:
Applies to all Board Members and Employees.

CODE OF BUSINESS CONDUCT
Festival Hydro values its reputation and the trust that exists between Festival Hydro, its employees, the public, our customers, and our business associates.

As Directors and/or Employees of Festival Hydro, we are committed to apply and maintain high standards of integrity and ethics in our business practices. Conduct must be able to withstand public scrutiny at all times. This policy describes how Festival Hydro employees are expected to conduct themselves while working for the organization.

This guide will help you to:

- Understand the Code of Business Conduct Policy

- Avoid situations where your personal interests' conflict or may conflict with the interests of Festival Hydro

- Know what to do if you think you are in a potential conflict of interest.

Confidentiality

- Strategic, operational, customer specific or any other confidential information of Festival Hydro Inc. should never be given to an outside firm or individual without the expressed written direction of the Board of Directors or the CEO. Any improper transfer of material or disclosure of information with or without personal gain constitutes unacceptable conduct.

- Any confidential information pertaining to Festival Hydro Inc. that is used by employees for the operations and administration of Festival Hydro Services Inc. shall be kept confidential in the strictest manner.

Use of Festival Hydro Property

- Employees will not use, or allow someone to use facilities, equipment, supplies or other resources for activities that are not associated with Festival Hydro unless prior approval is received by senior management.
- Improper use, carelessness, destructive or unsafe handling of company assets is both costly and hazardous. It is the responsibility of each employee to protect the assets of

Festival Hydro and to report appropriately any damage, defect or need for repair to prevent further deterioration and or injury to others.

Vendor Relationships

- We protect Festival Hydro's reputation by refusing to make purchasing decisions based on favoritism, prejudice, preferential treatment or personal gain. Decisions are made honestly and with integrity using such criteria such as competitive pricing, quality, delivery and service. We treat suppliers courteously, respectfully and in a professional manner.

- Employees will not accept any form of kickbacks, bribes or substantial gifts or special consideration as a result of any transaction or business dealing involving Festival Hydro, its' suppliers, contractors or customers. Employees may not accept any gift or give any gift or benefit if it influences or appears to influence them in the performance of their duties. The exception to this are gifts of minimal value such as coffee mugs, pens, t-shirts and reasonable business lunches, golf green fess, sporting event etc.

Special Treatment

- Employees may not use their position to give anyone special treatment that would advance their interests or the interests of their family, friends or business associates.

Outside Work or Business Activities

- Employees may not participate in any outside work or business activity that conflicts with Festival Hydro, or could be perceived as conflicting with Festival Hydro.

Conflict of Interest

- Employees, directors, or officers that have financial or material interests in a Festival Hydro business transaction, or have family members, friends or business associates with such interest, may not represent or advise the company in such transactions.

This guide is for employee information and protection. Sometimes it can be difficult to recognize a conflict. Talk to your Manager or the Chief Financial Officer as soon as possible if you:

- Are not sure if a situation you face presents a conflict of interest.
- Think you are in a conflict.
- Are not sure if a specific part of the policy applies to you.

Conflict of Interest – Directors and Officers

A Director and/or an Officer of FHI who is a party to, or have material interests in a Festival Hydro business transaction, or have family members, friends or business associates with such interests, shall disclose a 'conflict of interest' as per the requirements of the Ontario Business Corporations Act (OBCA). "

Such conflicted Director or Officer shall not attend (recuse from) any part of a meeting of directors during which the business transaction is discussed and shall not vote on any resolution to approve such business transaction.

On an annual basis, both Directors and Employees will sign off on The Code of Conduct.

Revision History		
Rev	**Date**	**Changes**
	October 2006	Procedure created
1	September 2013	Last known revision prior to Revision History added
2	December 16, 2016	Added to Compliance Science and assigned a Document #
	December 2017	Document review, no changes
	December 2018	Document review, no changes
	December 2019	Document review, no changes.
	December 2020	Document review, no changes.
	December 2021	Document review, no changes.
3	December 2022	Document reviewed by Board – Directors and Officers section added under Conflict of Interest clause

Attachment 1 – 7

Conditions of Service Updates

Festival Hydro Conditions of Service Document Version 5 Revision – Listing of Revisions from Version 4 – April 2014

TITLE PAGE	
Version 5 Conditions of Service	Version 4 Conditions of Service
• Added Revision 5 and its effective date February 4, 2023.	• Listed as Revision #4 on Title Page.

PREFACE	
Version 5 Conditions of Service	Version 4 Conditions of Service
Preface • A preface section was added to introduce the Conditions of Service document as a means for communicating the types and levels of service available to the Customers within Festival Hydro Inc.'s service area. • Also describes the general outline of the document and overview of changes from the previous version.	There was no preface

SECTION 1 – INTRODUCTION	
Version 5 Conditions of Service	Version 4 Conditions of Service
• We have included a glossary of terms and listing of acronyms used in these Conditions of Service to assist you, which can be found in Section 4.0 Glossary of Terms.	• There was no reference to the Glossary of Terms in the introduction section 1 Introduction.
1.1 Identification of Distributor and Service Territory • Reference was made to the Festival Hydro Distribution License ED-2002-0513 and removal of the reference to the transitional distribution license. • A key map of the service territory was added for reference • Paragraphs 4 – 17 from version 4 were removed as the content is best described and applicable to other sections of the Conditions of Service Document.	1.1 Identification of Distributor and Service Territory • No key map was provided. • Listed a reference to the transitional distribution license. • Paragraphs 4 – 17 are best described in other sections of Revision 5.

1.2 Related Codes and Governing Laws • List of laws, regulations and codes was expanded to a list of 33 • Updated references to the Electric Utility Safety Rules (EUSR) and Safe Practice Guides issued by Infrastructure Health and Safety Association (IHSA).	1.3 Related Codes and Governing Laws • A listing of only 9 laws, regulations and codes was included • Incorrect references to current EUSR rules and Safe Practice Guides from IHSA.
1.3 Interpretations Extensive revisions to this section that include: • Festival Hydro's rights to provide interpretation or intent of the conditions of service document. • Update to be inclusive of any gender identity for words referring to gender. • Definition of Festival Hydro designated holidays related to business closure. • Recognition of the OEB as the arbitrator for interpretation of the Conditions of Service	1.3 Interpretations • Older reference for wording reflective of gender that was not inclusive all gender identities. • Missing information on business closure for designated holidays.
1.4 Amendments and Changes Added: Festival Hydro reserves the right to make changes to these Conditions of Service at any time.	1.4 Amendments and Changes
1.5 Contact Information • Added: Festival Hydro offers online services and forms for the convenience of Customers. • Added: Business Hours information related to Call Centre, walk in hours, appointment requests for Engineering, Operations, Administrative and Management Staff.	1.5 Contact Information • Online self serve online services and forms were not mentioned. • No business hours or availability information provided.
1.6 Customer Rights All content from Version 4 was omitted. New wording reflective of Customer rights to access the Festival Hydro distribution system and services. Also included rights for one free annual disconnect and reconnect of service during normal business hours at no cost. Added: New subsections 1.6.1 Obligation to Sell Electricity, 1.6.2 Access to Meter Information, 1.6.3 Identification, 1.6.4	1.6 Customer Rights Wording was more reflective of Festival Hydro's limits of liability for damages which is described in a new subsection 1.6.4 Liability for Damages in Version 5.

Liability for Damages,	

1.7 Distributors Rights	
Version 5 Conditions of Service	Version 4 Conditions of Service
1.7 – General • New Section – several provisions added • No one can change a provision of the CoS verbally or otherwise. • FHI may require n alternative bid contractor o prove it is qualified. • Customer require to provide sufficient lead time • FHI may limit or cease connection in an emergency	1.7 – General • None
1.7.1 – Assignment • New Section assignment of rights by FHI	• None
1.7.2 Access to Customers Property • Significant expansion to existing Section ○ Added Section 40 of *Electricity Act* - Powers of Entry information ○ Added FHI right to add load limiter or remote disconnect device	1.7.1 – Access to Customer Property
1.7.3 – Safety of Equipment • Included most of existing Section 1.7.2 • Minor expansion to existing Section	1.7.2 – Safety of Equipment
1.7.4 – Operating Control • Included most of existing Section 1.7.3 • Non relevant paragraphs moved to correct Sections	1.7.3 – Operating Control
1.7.5 – Damaged Electrical Equipment • Moved existing paragraphs to this separate section	• None
1.7.6 – Repairs to Defective Customer Electrical Equipment • Similar to existing	1.7.4 – Repairs to Defective Customer Electrical Equipment
1.7.7 – Repairs of Customer Owned Physical (Civil) Structures • Same as existing …slightly reworded	1.7.5 – Repairs of Customer's Physical Structures
1.7.8 – Allocation of Electricity During Emergencies • New Section with wording taken from other CoS	
1.7.9 – Force Majeure	

• New Section – primarily wording taken from 2.3 of the DSC	
1.7 Disputes Added Title "Disputes New wording describing the Festival Hydro dispute resolution process and timing. New wording referencing the OEB Consumer Complaint Response Process and OEB E-Portal.	1.8 Disputes Missing title Content was reorganized into easy to follow bullets in version 5. Version 4 content referred Customers to submit their written complaints to OEB mailing address.

SECTION 2 – DISTRIBUTION ACTIVITIES (General)	
Version 5 Conditions of Service	Version 4 Conditions of Service
2.0.1 – Locating Underground Powerlines • New Section • Wording taken from existing CoS and other CoS	• Found in various sections not specific to Locates
2.0.2 – Temporary Connections • New Section – made generic - pertains to both General Service and Residential Service • Wording taken from existing CoS and other CoS	• Found in Section 2.3.2 - Temporary Services (other than residential)
2.0.3 – Number of Services • New Section • Wording taken from existing CoS and other CoS	• Found in various sections not specific to Number of Services
2.0.4 – Services and Swimming Pools • New Section – made generic – pool could be residential or commercial • Wording taken from existing CoS and other CoS	• Found in Section 3.1.1.2 – Residential – Services over Swimming Pools

2.1 Connections	
2.1 – Connections • Extensively rewritten and reorganized • Recognises FHI obligations to make an offer to connect • Added that the obligation to meet statutory building approvals is upon the Customer	2.1 – Connections – Process and timing • Moved paragraphs to various sections in the new Section 2.1
2.1.1 – Building that Lies Along • Same information as old section but reworded	2.1.1 – Building that Lies Along

2.1.1.1 – Connection Charges – Residential Class Customers • Includes definition of Basic Connection and Variable Charge	2.1.1.1 – Connection Charges • Includes both Residential and General Service connection charges
2.1.1.2 – Connection Charges – General Service Class Customers • All connection costs are Variable Charge	
2.1.2 – Expansions/Offer to Connect 2.1.2.1 – General • Added explanation of responsibilities • Added response timing as per DSC • Added explanation of what is included in the offer to connect	2.1.2 – Expansions/Offers to Connect • Moved wording to various appropriate sections 2.1.2.1 – Offer to Connect • Included in General Section
2.1.2.2 Contribution in Aid of Construction (CIAC) – also known as Capital Contribution • Reworded and explanations expanded • Replaces Existing 2.1.2.2 and 2.1.2.3	2.1.2.2 Capital Contributions and Connections Fees • Removed references to Connection Fees – already covered. • Removed Tables 1.1, 1.2and 2.1 replaced with new wording and Appendix B
2.1.2.3 – Expansion Deposit • Replaces Existing 2.1.2.3	2.1.2.3 – Settlement of Capital Contributions and Expansion Deposits
2.1.2.4 Alternative Bids • New Section added to explain alternative bids	
2.1.2.5 – Rebates for Contributions in Aid of Construction Customers – Capital Contribution • Replaces Existing 2.1.2.4 • Added wording and explanations	2.1.2.4 – Rebates Related to Expansions • Replaced and expanded upon
	2.1.2.5 – System Expansion Agreements • Eliminated Section
2.1.2.6 Transmission System Expansions or Enhancement • New section added to explain customer responsibilities for upstream transmission costs.	
2.1.2.7 – Bypass Compensation and Gross Load Billing • New Section added to explain costs to FHI that will be recovered from some Customers due to various generation connections	
2.1.3 – Connection Denial • Expanded explanations	2.1.3 – Connection denial
2.1.4 – Inspections before Connection • Same as existing	2.1.4 – Inspections before Connection

2.1.5 – Relocation of Plant • Reworded but fundamentally the same as existing	2.1.5 – Relocation of Plant
2.1.6 Easements • Divided into two Sections • 2.1.6.1 Registered Easements • Expanded explanations and wording to explain cost responsibility • And 2.1.6.2 – Unregistered Easements • New Section to explain unregistered easements	2.1.6 Easements • Revised
2.1.7 Contracts New second paragraph reference to the existence of an implied contract and Festival Hydro's rights to disconnect the customer for any cause listed under Section 2.2.	2.1.7 Contracts No mention of implied contract and Festival Hydro's rights to disconnect.
2.1.7.2 Implied Contract No Changes	
2.1.7.3 Special Contracts New second paragraph referencing connection agreement terms defaulting to terms of Appendix D of the DSC where no contract exists between Festival Hydro and an Embedded Generator, Embedded Distributor, Large User or a Customer Owned Sub-station. New third paragraph requiring 5 business day notice for Customers wishing to close their accounts.	2.1.7.3 Special Contracts No reference for Customers wishing to close their accounts.
2.1.7.4 Payment by Building Owner New third and fourth paragraphs. Third paragraph refers to tenants wishing to take responsibility for the service and Contract for Electrical Service. Fourth paragraph describes Festival Hydro's rights and process if the landlord/owner refuses responsibility for account set up for continuation of service where a tenant has moved out and a new tenant hasn't assumed responsibility for the account.	2.1.7.4 Payment by Building Owner
2.1.7.5 Opening and Closing of Accounts This subsection has been totally modified with new content that includes convenient online self help options for Customers wishing to open and close accounts. New content reorganized describing means for opening new accounts.	2.1.7.5 Opening and Closing of Accounts Specifics on the requirements for Customers to provide personal information and the use to identify customers in the future was not included in Version 4. Online self help options for opening and closing of accounts was not available in Version 4.

Description of information required to open an account and personal information required from the account holder for identification purposes. New third, fourth, fifth paragraphs. Same 10 business day advance notice for opening non-residential accounts. New paragraph seven for reconnection of service requests. Reorganized content describing process for Customers requesting closing of their account and cancelling service.	
2.2 Disconnections	
2.2 Disconnections Update to 19 possible causes for disconnection. Fourth paragraph modified to include content on the removal of meters and service conductor when services have been disconnected for more than a year. Also added in some instances the requirement for ESA inspection prior to reconnection and the Customer's responsibility for costs associated with the reconnection. New content for paragraphs six to nine. Content related to the notification procedure for service defects requiring disconnection has been added. New content added related to disconnection of a Service to perform repairs or alterations to the Distribution System.	2.2 Disconnections List of only 11 causes for disconnection which needed updating. Missing content for procedure of notice to Customers for service defects requiring disconnection.
2.2.1 Disconnection and Reconnection – Process and Charge Paragraphs one to three no changes. Removed paragraphs four as the content was best described in sections 2.2 Disconnections. Removed paragraph five as it was described in section 2.2 Disconnections paragraph four.	2.2.1 Disconnection and Reconnection – Process and Charge Contents from paragraph four and five best described in Section 2.2 Disconnection Section
2.2.2 Unauthorized Energy Use This subsection was re-written to describe Festival Hydro's rights and obligations regarding unauthorized energy use.	2.2.2 Unauthorized Energy Use

2.3 Conveyance of Electricity	
Version 5 Conditions of Service	Version 4 Conditions of Service
2.3.1 – Guarantee of Supply • Similar to existing	2.3.1 – Guarantee of Supply
2.3.2 Power Quality	2.3.2 - Power Quality

• Same as existing including subsections 2.3.2.1, 2.3.2.2, and 2.3.2.3	
2.3.2.4 Notification for Planned Interruption • Title changed ; wording expanded	2.3.2.4 Notification for Interruption
	2.3.2.5 – Notification for Interruption to Customers on Life Support • Festival Hydro is unable to supply this service • Section was removed from CoS
2.3.2.5 – Emergency Interruptions for Safety • Renumbered existing 2.3.2.6	2.3.2.6 – Emergency Interruptions for Safety • Renumbered to 2.3.2.5
2.3.2.6 Emergency Service (Trouble Calls) • Renumbered existing 2.3.2.7	2.3.2.7 Emergency Service (Trouble Calls) Renumbered existing 2.3.2.6
2.3.2.7 – Voltage Fluctuations • New section	
2.3.2.8 – Frequency Fluctuations • New section	
2.3.2.9 – Voltage Flicker Limits • New section	
2.3.2.10 – Voltage Unbalance Limits • New section	
2.3.2.11 – Neutral-to-Earth Voltage • New section	
2.3.3 – Electrical Disturbances • Reworded and expanded	2.3.3 Electrical Disturbances
2.3.3.1 – Unplanned Outages and Emergency Conditions • New Section	
2.3.4 – Standard Voltage Offerings • Similar to existing section…expanded wording	2.3.4 – Standard Voltage Offerings
2.3.4.1 – Primary Voltages • section explaining what primary voltages are available where	Primary Voltages – were part of 2.3.4
2.3.4.2 – Secondary Voltages section explaining what secondary voltages are supported by Festival Hydro	Secondary voltages were part of 2.3.4
2.3.4.2.1 – Determining the Supply Voltage for a Connection Asset • new section	
2.3.4.2.2 – Maximum Transformer Size Supplied by Festival Hydro • New section describing Festival Hydro's existing procedure	

<table>
<tr><td>• Added Table 2</td><td></td></tr>
<tr><td>2.3.4.3 – Over-current Protection
• New Section explaining that protection requirements may help define the voltage level serving a connection asset</td><td></td></tr>
<tr><td>2.3.5 – Voltage Guidelines
• Similar to existing</td><td></td></tr>
<tr><td>2.3.6 – Back-up Generators
No Changes</td><td></td></tr>
<tr><td colspan="2">2.3.7 - METERING</td></tr>
<tr><td colspan="2">The metering section was extensively revised to provide the user with greater accessibility to the information they were seeking. For example, the meter location was defined in several different existing sections. This information was extracted from multiple existing locations and consolidated in one place.</td></tr>
<tr><td>2.3.7 – Metering
• Same as existing</td><td></td></tr>
<tr><td>2.3.7.1 – General
• Extensively revised to provide only general information about metering</td><td></td></tr>
<tr><td>2.3.7.2 – Meter Location
• New section that consolidates all information on meter location</td><td></td></tr>
<tr><td>2.3.7.2.1 – Meter Rooms and Meter Access
• New Section that consolidates all information on meter rooms and meter access</td><td></td></tr>
<tr><td>2.3.7.3 – Metering Cabinets (Current Transformer Boxes)
• New section that consolidates all information on Metering Cabinets</td><td></td></tr>
<tr><td>2.3.7.4 – Metering when Using Switchgear (Over 400A)
• New section that consolidates all information on Switchgear</td><td></td></tr>
<tr><td>2.3.7.5 – Manufactured Metering Load Centers
• New section that consolidates all information on Manufactured Metering Load Centers</td><td></td></tr>
<tr><td>2.3.7.6 – Interval Metering
• Revised existing section 2.3.7.5 to current DSC requirement. Eliminated much out of date information</td><td></td></tr>
<tr><td>2.3.7.6.1 Customer Access to Interval Meters
New subsection describing the terms and conditions in which a Customer may have access to interval meter data, including options available.</td><td>No subsection in version 4.</td></tr>
<tr><td>2.3.7.7 – Meter Reading</td><td></td></tr>
</table>

• Same as existing 2.3.7.6	
2.3.7.8 Final Meter Reading • Same as existing 2.3.7.7	
2.3.7.9 – Faulty Registration of Meters • Same as existing 2.3.7.8	
2.3.7.10 Meter Dispute Testing • Same as existing 2.3.7.9	
2.3.7.11 – Distributed Energy Resources and Net Metering • Revised existing 2.3.7.10 to eliminate references to FiT/microFiT and add Net Metering • Includes all DER	
2.3 Tariffs and Charges	
2.4 Tariffs and Charges 2.4.1 Service Connection Reworded this subsection with terms describing Festival Hydro's Distribution Rates and Specific Service Charges and where they can be found online. Also added paragraph two describing when distribution rates are charged to a customer and how Customers are notified when distribution rates are revised.	2.4.1 Service Connection Notice to Customers has changed since version 4 was published.
2.4.2 Energy Supply The content from version 4 subsection 2.4.1.1 was incorporated in a rewritten section 2.4.2 Energy Supply paragraph 1. Changes to this section include Festival Hydro's obligations under the Retail Settlement Code to manage Service Transfer Request from a Customer.	2.4.1.1 Customers Switching to a Retailer This content is a best fit to the 2.4.2 Energy Supply section as per the DSC Appendix A.
	2.4.1.2 Supply Deposits and Agreements This section was best described in a new section 2.4.3 Deposits as per the DSC Appendix A.
2.4.3 Deposits Added content to describe the prudential requirements for a property development so that Festival Hydro may order equipment necessary to service the development.	2.4.3 Security Deposits Title as per the DSC Appendix A should be Deposits.
2.4.3.1 Security Deposit This subsection has been updated to allow for flexibility in policy to collect security deposits based on changes to OEB rules related to security deposits that can be collected from Customers.	

2.4.3.2 Use of Security Deposits in Arrears Management Program No Change to wording	There was no subsection number in Version 4.
2.4.3.3 Amount of Deposit No change to wording	There was no subsection number in Version 4.
2.4.3.4 Waiver Policy This subsection was revised to reference the latest requirements in the DSC related to waiving security deposits. Also including wording reflecting the requirement in DSC to refund security deposits	There was no subsection number in Version 4. Content in this section was not aligned to the latest DSC which is subject to change as per OEB regulations.
2.4.4 Billing Title change to "Billing" as per DSC Appendix A. Wording change to allow for flexible billing cycle and frequency. Added a second paragraph describing when is a bill is deemed to have been issued to a Customer	2.4.4 Billing and Collections This section was specific to billing frequency and flexibility is needed whenever billing rules change as per OEB rules.
2.4.4.1 Billing Options New subsection added for Billing Options as required by the Retail Settlement Code. Wording added suggesting Festival Hydro's preference for providing the Distributor-Consolidated Billing option.	No subsection 2.4.4.1 Billing Options
2.4.4.2 Prorating Bills and Service Charges New subsection describing methodology for prorating first, final and billing involving rate change.	No subsection 2.4.4.2 Prorating Bills and Service Charges
2.4.4.3 Estimating Bills New subsection describing methodology for reasonably estimating bills using billing or account history where no meter reading is available.	No Subsection 2.4.4.3 Estimating Bills
2.4.4.4 Adjustment Factor New subsection describing the Total Loss Factor and how it is applied to meter readings.	No Subsection 2.4.4.4 Adjustment Factor
2.4.4.5 Power Factor New subsection describing the requirement of minimum power factor of 90% and the when the minimum is exceeded use of 90% of kVA is used for demand billing.	No Subsection 2.4.4.5 Power Factor
2.4.4.6 Billing Breakdown Request New subsection describing Festival Hydro option to charge a Customer the cost for providing a detailed breakdown of a service billing.	No Subsection 2.4.4.6 Billing Breakdown Request
2.4.5 Payments and Late Payment Charges	2.4.5 Payment of Overdue Interest Charges

New Subsection title to align with the DSC Appendix A. New wording describing when Festival Hydro bills are due for payment and the application of late payment interest charges for overdue accounts. Also states Customers being responsible for reconnection charges where the service has been disconnected due to non-payment. Added the Customer being responsible to pay additional charges where payments have been returned by their financial institution as non-sufficient funds.	This subsection does not align with the DSC
2.4.5.1 Payment Allocation New subsection describing the Festival Hydro methodology for allocating payments where the payment is insufficient to cover the balance owning on the account. The order of allocation is listed for the Customer to easily follow how payments will be allocated to the bill.	No Subsection 2.45.1 Payment Allocation
2.4.5.2 Arrears Payment Agreements New Subsection describing the methodology and Customer eligibility to enter into an arrears Payment Agreement. Also describes the process if the Customer fails to perform their obligations under an Arrears Payment Agreement. This subsection aligns with Section 2.7 Arrears Payment Agreements of the DSC October 1, 2022 edition.	No Subsection 2.4.5.2 Arrears Payment Agreements
2.4.5.3 Payment Options New Subsection describing payment options available to Customers for paying the electricity bill.	No Subsection 2.4.5.3 Payment Options Some of the content from Section 2.4.5 appears in Version 2.4.5.3 Payment Options.
2.4.5.4 Late Payment Interest Charges and Non-Payment Charges New Subsection describes in detail the late payment interest rate and how it is applied to non-payment charges.	No Subsection 2.4.5.4 Late Payment Interest Charges and Non-Payment Charges
2.5 Customer Information	
2.5 Customer Information New paragraph 2 content has been added reflective of current provincial and federal privacy legislation as it relates to the collection, use and disclosure of Customer personal information.	2.5 Customer Information All previous content from Version 4 is still within Subsection 2.5.
2.5.1 Provision of Current Usage Data to Customers	No Subsection Provision of Current Usage Data to Customers

New Subsection describing the Festival Hydro's methodology and availability of electricity usage data to Customers, Customer's Retailer or Customer authorized third party.	

SECTION 3 – CUSTOMER CLASS SPECIFIC	
Version 5 Conditions of Service	Version 4 Conditions of Service
3.1 Residential Service	
3.1 – Residential Service Includes the same material as in existing section. Some existing wording moved to 2.3.7 Metering, 1.7.2 Access to Customer Property and other new Sections. Enhanced and expanded wording Reorganized for better user access	
3.2 General Service (Below 50 kW)	
3.2 – General Service (Below 50 kW) Includes the same material as in existing section. Some existing wording moved to 2.3.7 Metering, 1.7.2 Access to Customer Property and other new Sections Enhanced and expanded wording Reorganized for better user access.	
3.3 General Service (Greater than 50 kW)	
3.3 – General Service (Greater than 50 kW) Includes the same material as in existing section Enhanced and expanded wording Reorganized for better user access. Residential Subdivisions moved to 3.1.10	
3.4 Large User General Service (above 5000 kW)	
3.4 – Large User General Service (above 5000 kW) New section matches the DSC Appendix A.	
3.5 Embedded Generation	
3.5 – Embedded Generation Revised text to reflect changes to DSC	Incorrect numbering of the Section 3.4 Embedded Generation as per DSC Appendix A
3.6 Embedded Generation	
3.6 – Embedded Market Participant Includes the same material as in existing section Enhanced and expanded wording	Incorrect numbering of the Section 3.5 Embedded Market Participant as per DSC Appendix A
3.7 Embedded Distributor	
3.7 Embedded Distributor Includes the same material as in existing section Enhanced and expanded wording	Incorrect numbering of the Section 3.6 Embedded Distributor as per DSC Appendix A
3.8 Unmetered Connections	

3.8 Unmetered Connections 3. 8.1 General New subsection wording describing the type of unmetered connections allowed by Festival Hydro, and treatment of connections for the purposes of billing.	Incorrect numbering of the Section 3.7 Unmetered Connections Incorrect numbering of the section as per DSC Appendix A This section was not numbered in accordance with the DSC Appendix A.
3.8.2 Unmetered Connections – Customer Obligations New subsection wording describing the Customer obligations for establishing, updating and maintaining unmetered connections.	
3.8.3 Unmetered Connections – Festival Hydro Obligations New subsection wording describing Festival Hydro's obligation for establishing, updating and maintaining information for the purposes of billing unmetered connections. Additional wording describing process if unmetered loads become variable loads requiring metering or Customer-specific cost allocation study at the Customer's expense.	
3.8.4 Unmetered Load Types New subsection describing examples of the current unmetered load types recognized by Festival Hydro.	
3.8.5 Unmetered Connections Electric Servicing New subsection wording describing the Festival Hydro conditions for providing electric servicing to unmetered connections.	
SECTION 4 – GLOSSARY OF TERMS	
4.1 Acronyms New subsection added to list acronyms used throughout the Conditions of Service document	
SECTION 5 – APPENDICES	
Appendix Section has been modified to only 2 appendixes with references to the Festival Hydro website for supporting documentation for the Metering Technical Specifications.	
Appendix A – Offer to Connect Methodology and Assumptions	Removed Tables 5 These tables were replaced with Appendix B Interpretive Drawings for Demarcation Points
Appendix B – Demarcation Point Interpretive Drawings This Appendix B replaces the Tables found in Version 4.	

Attachment 1 – 8

Customer Satisfaction Survey

Festival Hydro Inc.

2022 Customer Satisfaction Survey Report

oraclepoll RESEARCH

October 2022

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Background & Overview

Festival Hydro commissioned Oraclepoll to conduct an engagement survey of its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by Festival Hydro. The telephone method of data collection was used, and N=400 residential and small commercial (business) customers were interviewed.

This 2022 survey is the second conducted by Oraclepoll and when possible results are compared with the previous 2020 poll. Sampling and methodology are consistent with the previous poll.

This report contain an executive overview of the findings, while a separate report in Excel includes the results by each question.

Methodology & Logistics

Study Sample

Festival Hydro provided Oraclepoll with a database of their residential and small commercial business customers to be interviewed. The sample was stratified to ensure that a representative number of business (N=40) in relation to residential (N=360) customers were surveyed; as well as those from Stratford N=278 and outside that community (N=122).

	Residential	Business
Stratford	**N=252**	**N=26**
Outside Stratford	**N=108**	**N=14**
TOTAL	**N=360**	**N=40**

Stratford	**N=278**	**69.5%**
Outside Stratford	**N=122**	**30.5%**

Residential	**N=360**	**90.0%**
Business	**N=40**	**10.0%**

In addition, a proportionate number of residential and business customers were surveyed by area.

Survey Method

All surveys were completed by telephone online using Computer Assisted Telephone Interviewing (CATI). The numbers within each cohort sub-set were randomly selected.

Logistics

Surveys were completed between the days of October 3rd and October 18th, 2022. Initial calls to residents were made between the hours of 6:00 pm and 9:00 pm. Subsequent call-backs of no-answers and busy numbers were made on a (staggered) daily rotating basis up to 5 times (from

10:00 a.m. to 9:00 p.m.) until contact was made. At least one call was made on a weekend. Calls to business clients were made during business hours from 8:30 am to 6 pm with at least one call after 6 pm and one on a weekend. In addition, telephone interview appointments were attempted with those respondents unable to complete the survey at the time of contact.

Confidence

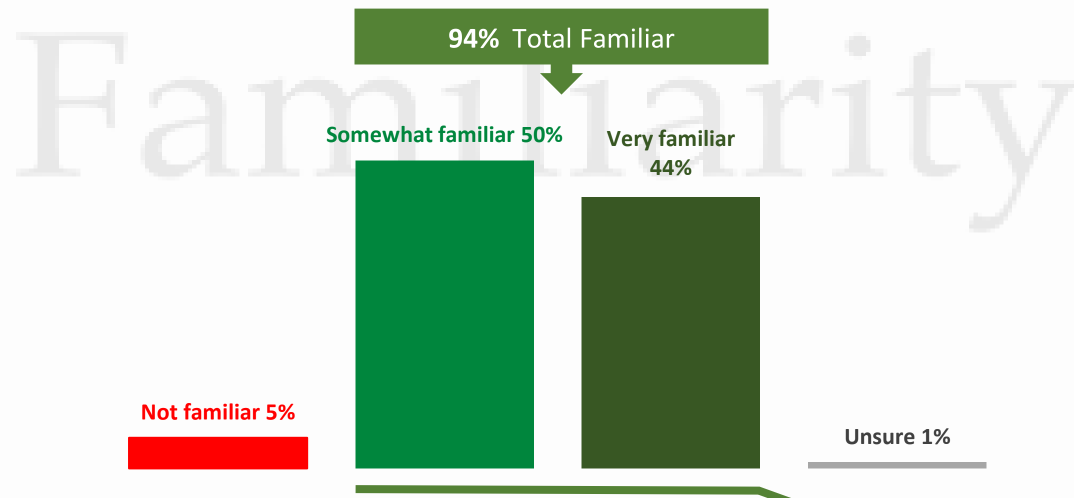
The margin of error for the total N=400 sample is ± 4.9%, $\frac{19}{20}$ times. The error rate for each of the residential (N=360) and business (N=40) sub-sets is ± 5.1% and ± 15.49%, $\frac{19}{20}$ times, respectively.

Core Measurement

All N=400 customers were first asked to rate their familiarity with Festival Hydro.

FAMILIARITY

Q1. "How familiar are you with Festival Hydro, which operates the electricity distribution system in your community? Are you very familiar, somewhat familiar, or not familiar?"



Nine in ten are somewhat familiar (50%) or very familiar (44%) with Festival Hydro, up +4% over 2020.

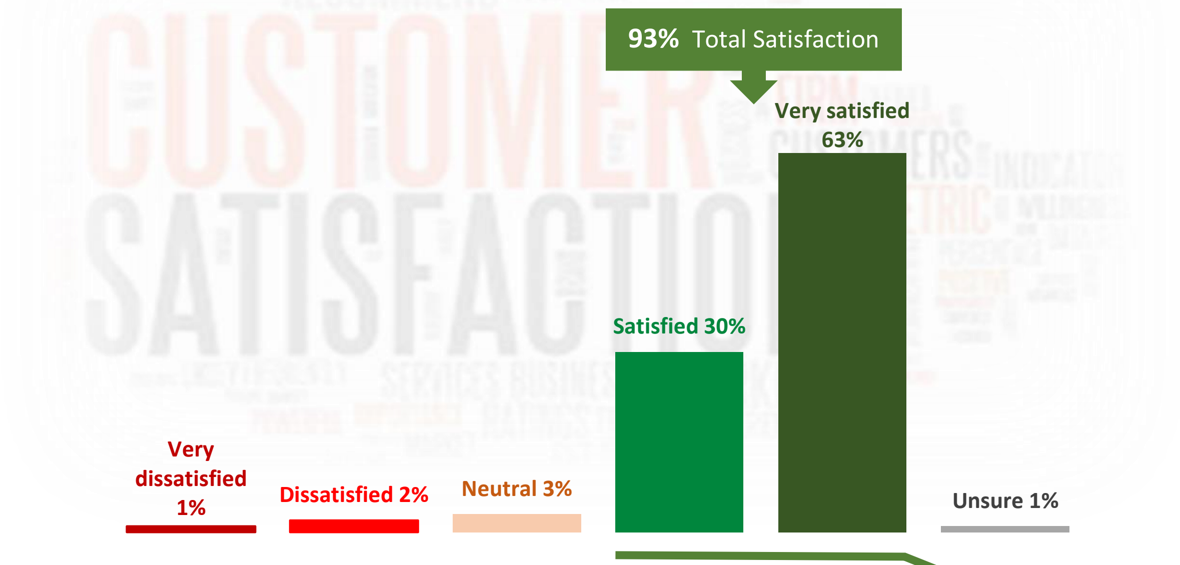
Familiarity is higher in Stratford, compared to areas outside of Stratford and among business customers in relation to the residential cohort.

BREAKDOWNS	TOTAL FAMILIAR
Stratford	*96%*
Outside of Stratford	*90%*
Residential	*93%*
Business	*98%*
TRACKING – N=400	
2020	*90%*
2018	*84%*

Next, all N=400 customers rated their satisfaction with the services they receive. A five-point rating scale was used from 1-very satisfied to 5-very dissatisfied.

SATISFACTION

Q2. "Overall, how satisfied are you with the services you receive and are provided to your community by Festival Hydro? Please use a scale from one very satisfied to five very dissatisfied."



Ninety three percent are satisfied (30%) or very satisfied (63%) with the services received, up +2% from 2020.

More Stratford respondents compared to those living outside Stratford were satisfied, while there was no variance between residential and business results.

BREAKDOWNS	TOTAL SATISFIED
Stratford	*95%*
Outside of Stratford	*88%*
Residential	*93%*
Business	*93%*
TRACKING – N=400	
2020	*91%*
2018	*90%*

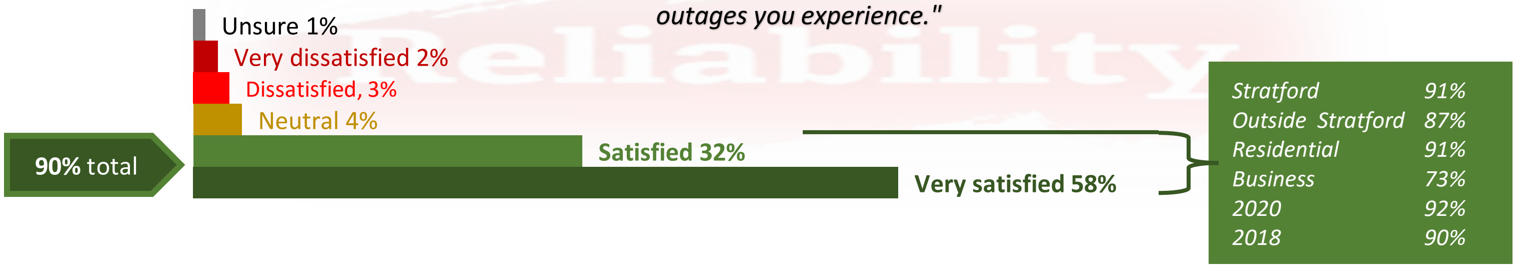
Reliability & Power Quality

Customers then rated the reliability and quality of their power across three areas, using a five-point rating scale from 1-very satisfied to 5-very dissatisfied.

"I would now like you to rate the reliability and quality of the electrical service you receive from Festival Hydro. For each area that I read, please respond using a scale from one very satisfied to five very dissatisfied."

RELIABILITY OF ELECTRICITY SERVICE

Q3. "The reliability of your electricity service – as judged by the number of power outages you experience."



RESTORATION TIMES

Q4. "The amount of time it takes to restore power once an outage occurs."

POWER QUALITY

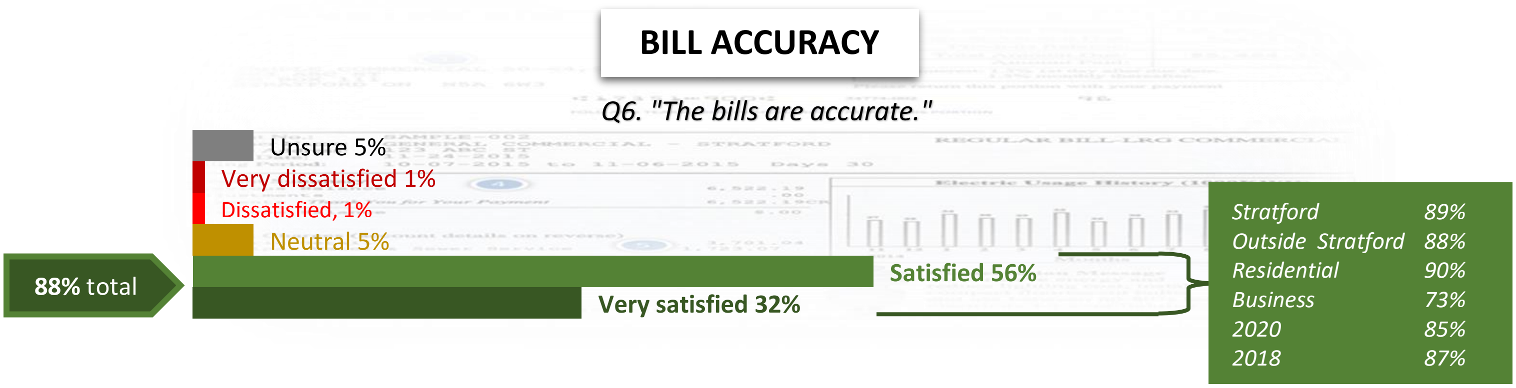
Q5. "The quality of the power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering or dimming of lights."

Ratings were consistent across the three areas with the quality of power scoring highest in terms of satisfaction at 92%, up slightly over 2020 (+1%). This was followed by the reliability of electricity service at 90% (down -2% over 2020) and then the amount of time it takes to restore power after an outage at 87%, also down -2%.

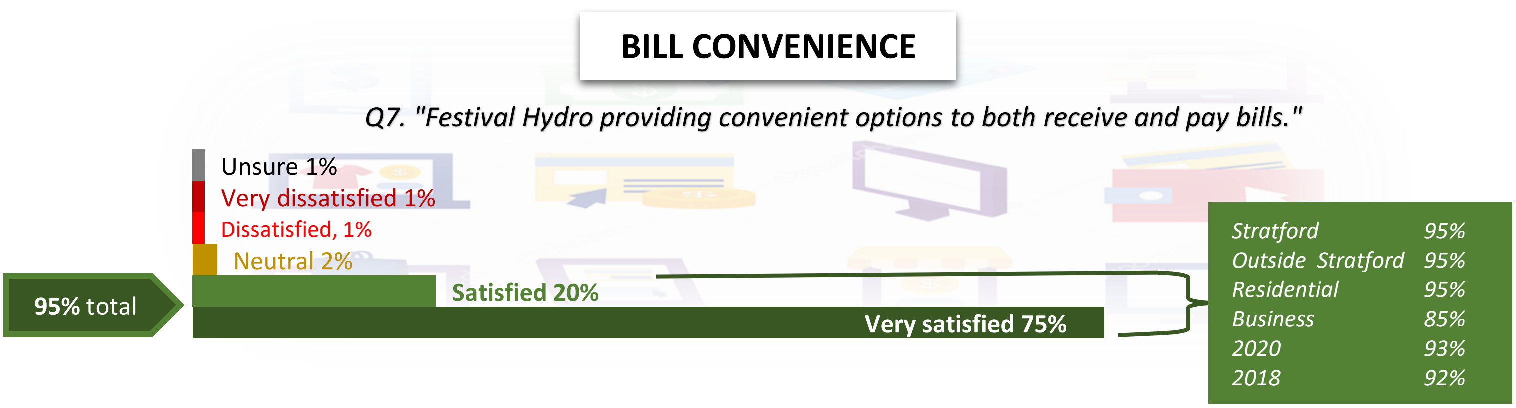
Billing & Payment

Billing was next rated in the areas of accuracy and convenient options to receive and pay. A five-point rating scale from 1-very satisfied to 5-very dissatisfied was used.

"I am now going to ask you rate the bills you receive from Festival Hydro in two areas, using a scale from one very satisfied to five very dissatisfied."



Eighty-eight percent are satisfied or very satisfied with the accuracy of bill, an increase of +3% compared to the 2020 survey period. Business results lagged behind those provided by residents.



Most customers or 95% said they were satisfied or very satisfied with Festival Hydro providing convenient options to receive and pay bills (+2% over 2020).

The N=23 or 5% that provided a rating other than satisfied or very satisfied were asked in an open-ended follow-up about what other options they would like. While N=6 were unsure or had no comment, those with responses had varied opinions with many focusing in on the cost of bills. For example, N=4 want the costs of the bill explained, N=3 would like detailed information involved in the costing and N=2 prefer lower rates. Other responses included having more payment options (N=2), having an App (N=2), bills easier to understand (N=1), rate relief (N=1) and in-person payments (N=1).

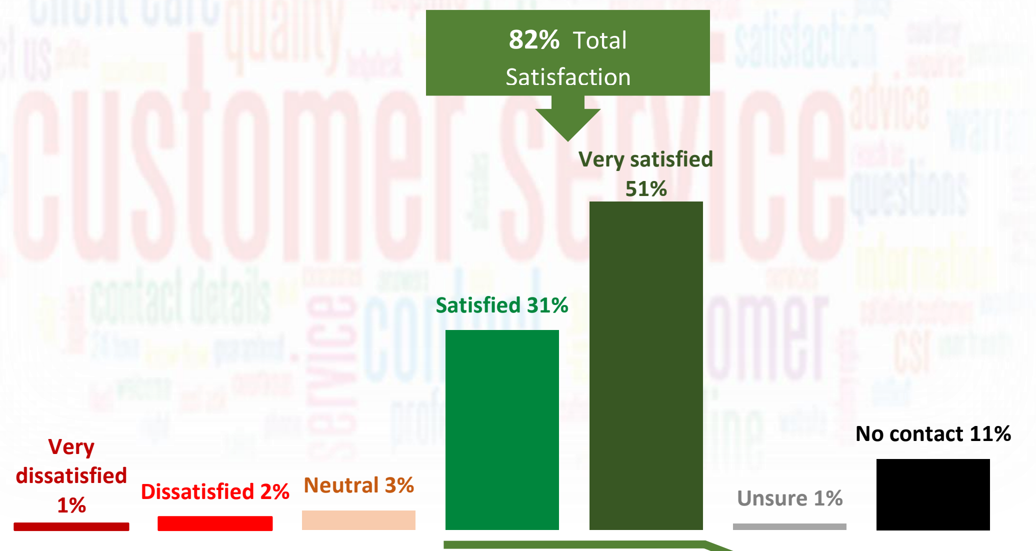
Customer Service Experience

A question about the overall customer experience was asked. A five-point rating scale from 1-very satisfied to 5-very dissatisfied was used.

"Next, I am going to ask you about the customer service you receive when dealing with employees of Festival Hydro, whether by telephone, email, in person or through online conversations, including social media."

SATISFACTION WITH CUSTOMER SERVICE

Q8. "Overall, how would you rate your satisfaction with the customer service provided by Festival Hydro? Please use a scale from one very satisfied to five very dissatisfied. (If you have not been in contact just let me know.)"



There was a +2% increase in satisfaction with the overall customers experience, with 82% of customers being satisfied (31%) or very satisfied (51%). Satisfaction scores were highest in Stratford and among residential customers.

BREAKDOWNS	TOTAL SATISFIED
Stratford	*85%*
Outside of Stratford	*76%*
Residential	*83%*
Business	*78%*
TRACKING – N=400	
2020	*80%*
2018	*67%*

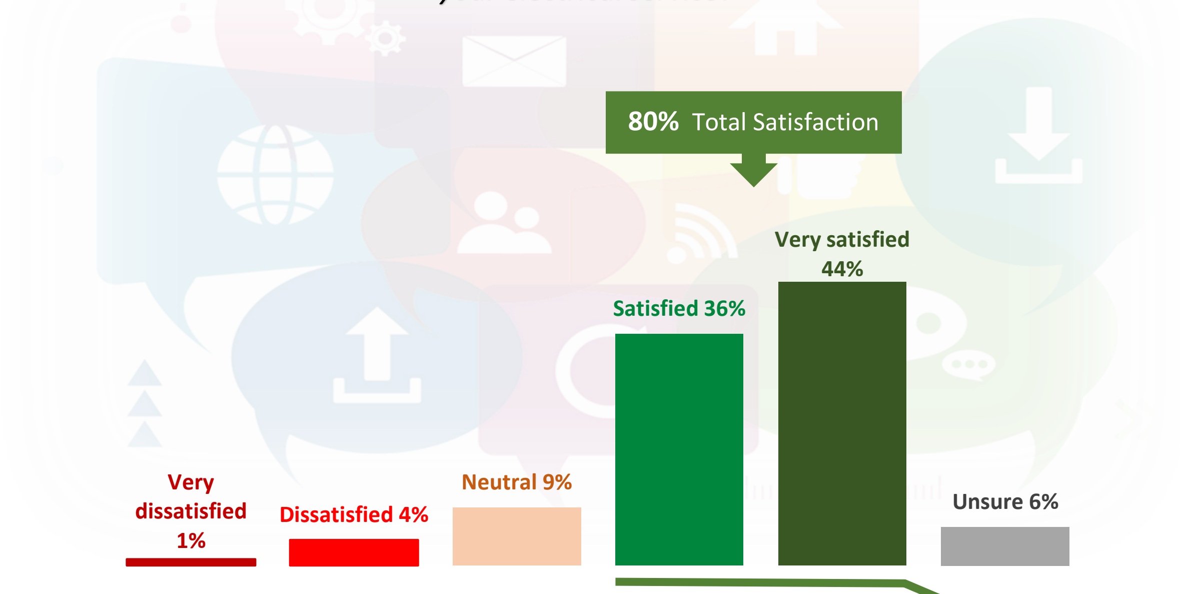
Communications

Using a five-point rating scale from 1-very satisfied to 5-very dissatisfied, customers then rated their satisfaction with the communications they receive from Festival Hydro.

"I would now like you to think about the communications that you may receive from Festival Hydro without talking directly to an employee. This may include information found on their website, bill inserts, advertising, notices, emails, or social media sites."

SATISFACTION WITH COMMUNICATIONS

Q9. "Overall, how would you rate your satisfaction with the communications that you receive from Festival Hydro related specifically to your electrical service?"



Eight in ten are satisfied (36%) or very satisfied (44%) with the communications they receive from Festival Hydro, down -3% from 2020. Results are better among Stratford residents and residential customers.

BREAKDOWNS	TOTAL SATISFIED
Stratford	*81%*
Outside of Stratford	*78%*
Residential	*80%*
Business	*75%*
TRACKING – N=400	
2020	*83%*
2018	*75%*

Price

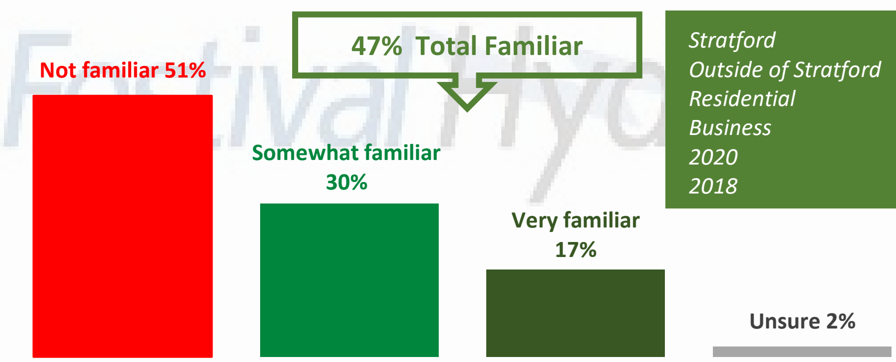
The following short statement was read to customers after which two questions related to the percentage of their bill that is remitted to Festival Hydro were asked.

"While Festival Hydro is responsible for collecting payment for the entire electricity bill, they retain only about [20%-25% of the average residential] [20-25% of the average small business] customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government, and regulatory agencies."

BILL REMITTANCE

Q10. "Before this survey, how familiar were you with the percentage of your electricity bill that went to Festival Hydro? Are you very familiar, somewhat familiar, or not familiar?"

There are 47% of customers that are familiar, with results higher in Stratford in relation to other areas. Findings are also +6% better when compared to the previous 2020 survey period.



Stratford	*51%*
Outside of Stratford	*40%*
Residential	*46%*
Business	*63%*
2020	*41%*
2018	*30%*

ATTITUDES TOWARDS BILL REMITTANCE

Q11. "Do you feel that the [Res: 20-25%] [GS: 20-25%] of your total electricity bill that you pay to Festival Hydro for the services they provide is very reasonable, somewhat reasonable, somewhat unreasonable or very unreasonable?"

Very reasonable	36%
Somewhat reasonable	31%
Somewhat unreasonable	13%
Very unreasonable	5%
Unsure	15%

67% total

Stratford	*69%*
Outside of Stratford	*61%*
Residential	*67%*
Business	*65%*
2020	*71%*
2018	*59%*

Two-thirds feel the percentage paid is somewhat or very reasonable, -4% less than in 2020.

Service Improvements

In an open-ended or unaided question, customers were asked what they would like Festival Hydro to do in order to improve the services it provides.

Q12 "Is there anything in particular you would like Festival Hydro to do to improve its services to you?"

Lower rates / prices	46%	+7%
None / unsure	21%	-8%
Help customers reduce usage / save money	13%	+4%
Improve communications	5%	+1%
Offer rebates / incentives	5%	-3%
Focus on renewables / green / alt energy	5%	+1%
Fewer outages / quicker responses	4%	n/c
Improved billing / payment options	2%	-1%

Cost issues were most named. Lower rates or prices was named by 46%, an increase of +7% over 2020, while 13% said they want information to help them save money (+4%) and 5% want rebates or incentives to save energy (-3%).

Customer Preference Outcome Priorities

Five areas related to spending priorities were rated in terms of their importance to customers using a five-point rating scale (1-not at all important to 5-extremely important). The table below combines the total unimportant (not at all & not important) as well as the total important scores (extremely important & important). It also compares the total important scores to 2020.

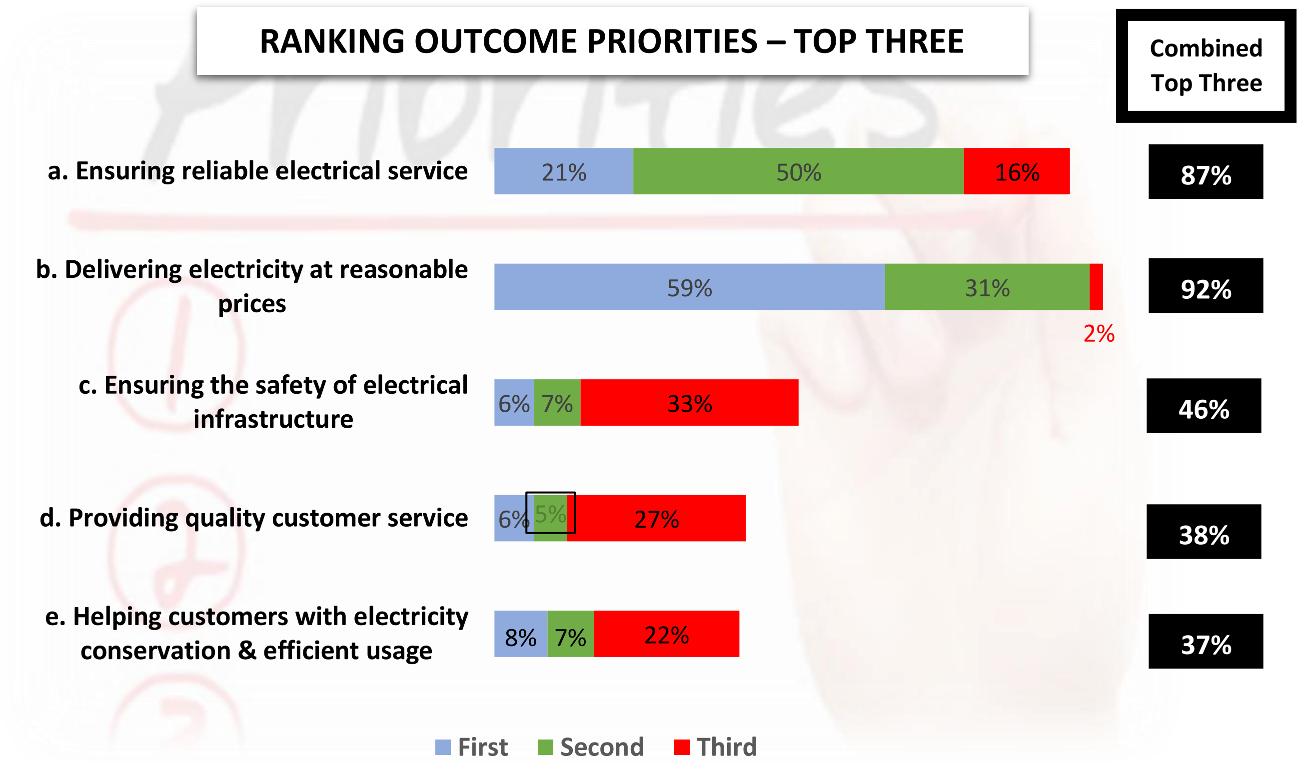
Q13. "Festival Hydro engages its customers to better understand how it should set spending priorities with ratepayer dollars. In recent interactions with customers, a number of priorities were identified for Festival Hydro. Using a scale from one not at all important to five extremely important, please tell me how important each of the following Festival Hydro priorities are to you as a customer?"

OUTCOME PRIORITIES	Unsure	Total unimportant	Neutral	Total important 2022	Total important 2020
A. Ensuring reliable electrical service	1%	1%	3%	96%	94%
B. Delivering electricity at reasonable prices	-	1%	2%	97%	95%
C. Ensuring the safety of electrical infrastructure	1%	5%	7%	87%	89%
D. Providing quality customer service	1%	2%	6%	91%	88%
E. Helping customers with electricity conservation and efficient usage	1%	3%	8%	88%	81%

While all areas rated high in terms of total importance, the strongest results were for delivering electricity at reasonable prices (+2% over 2020), closely followed by ensuring a reliable electrical service (+2%). The largest increase in importance was for helping customers with conservation and efficient usage (+7%).

Customers were then asked to rank in order of priority their top three areas of preference from the five spending areas (1-being highest). Unsure (don't know) results are excluded from the reporting in the chart below.

Q14. "Thinking of the priorities we just discussed, please indicate your top three in order of preference, starting with your highest priority."



Ensuring the delivery of electricity at reasonable prices had the most first priority references (59%) and the highest combined top three mentions at 92%, up +3% compared to 2020. Ensuring reliable electrical service was next most mentioned top three at 87%, a decrease of -7% from the 94% in the previous poll. Ensuring the safety of electrical infrastructure followed at 46%, an area that say the biggest drop (-9%), while 38% referenced quality customer service (+3%) and helping with electricity conservation and efficient usage at 37% (the largest gain area at +9%).

Customer Preference Reliability Priorities

Five areas related to reliability were rated in terms of their importance to customers using a five-point rating scale (1-not at all important to 5-extremely important). The table below combines the total unimportant (not at all & not important) as well as the total important scores (extremely important & important). It also compares the total important scores to 2020.

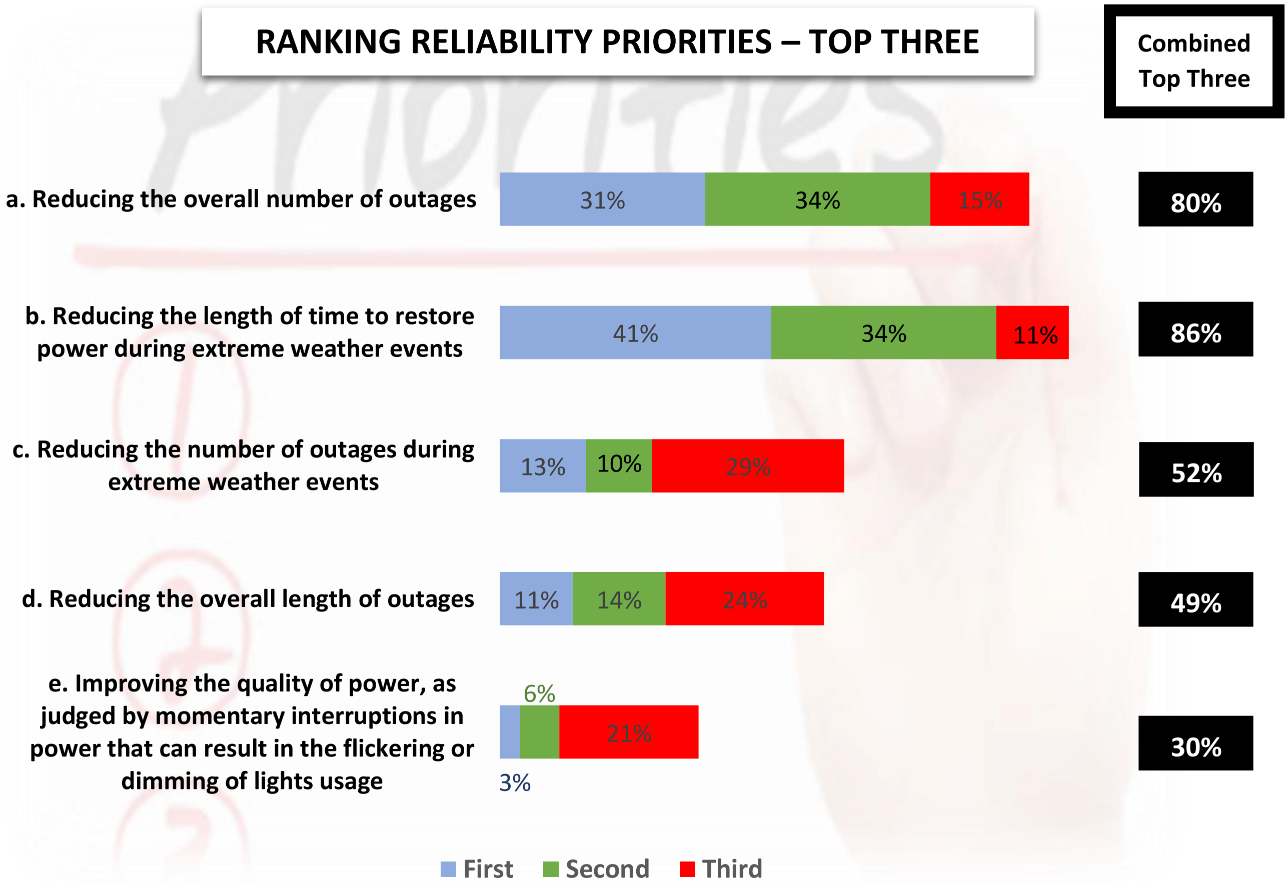
Q15. "We would now like your opinions about reliability as there are different outcomes when customers talk about power reliability. Using a scale from one not at all important to five extremely important, how important are each of the following Festival Hydro reliability outcomes to you as a customer?"

RELIABILITY PRIORITIES	Unsure	Total unimportant	Neutral	Total important 2022	Total Important 2020
A. Reducing the overall number of outages	1%	3%	9%	87%	83%
B. Reducing the length of time to restore power during extreme weather events	2%	3%	5%	90%	86%
C. Reducing the overall length of outages	1%	3%	10%	86%	84%
D. Reducing the number of outages during extreme weather events	1%	7%	7%	85%	81%
E. Improving the quality of power, as judged by momentary interruptions in power that can result in the flickering or dimming of lights	1%	7%	12%	80%	76%

Customers view all areas as being of high importance, with reducing the length of time to restore power during extreme weather rating highest at 90% (+4% compared to 2020), followed by reducing the overall number of outages at 87% (+4%). Reducing the overall length of outages came in a close third at 86% (+2%), next by reducing the number of outages during extreme weather events at 85% (+4%). While lowest scored in terms of relative importance was improving the quality of power, eight in ten still viewed it with importance (+4%).

Customers were then asked to rank in order of priority their top three areas of preference from the five reliability areas (1-being highest). Unsure (don't know) results are excluded from the reporting in the chart below.

Q16. "Thinking of the priorities we just discussed, please indicate your top three in order of preference, starting with your highest priority."



Reducing the length of time to restore power after extreme weather events had the most first priority references at 86% (81% in 2020), followed by reducing the overall number of outages at 80% (86% in 2020). The next tier included reducing outages during extreme weather at 52% (55% in 2020) and the overall length of outages at 49% (44% in 2020), while lowest was improving the quality of power at 30% (36% in 2020).

Communication

In an open question allowing for one top of mind response, customers were asked what method of communication they would prefer to receive notifications about outages or other important information.

Q17a. "Which technology or method of communicating information would you most prefer to receive notifications about outages, updates, or other important news from Festival Hydro?"

Email	36%
Text	23%
Telephone	14%
Facebook	8%
Smartphone App	8%
Website	6%
Twitter	4%
Unsure	1%

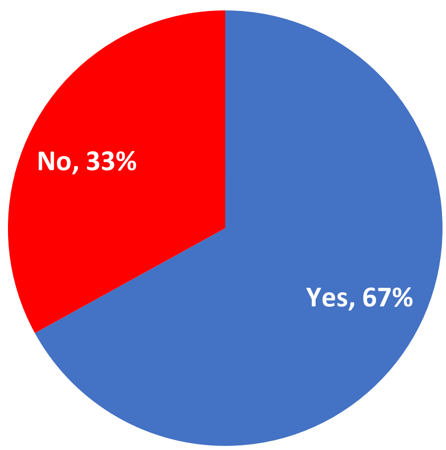
On the preferred method of outage information communication, email, followed by text messages and telephone were most named.

Self Serve Options

All respondents were first read a description and list of self serve options available on the Festival Hydro website. They were then asked if they currently or have in the past used any self-serve options. In addition, they were probed about what other self serve options they would like to have.

"Currently we offer the following self-serve options on our website: Start service, stop service, transfer service, streetlight service request, consumer choice election, equal billing enrollment, signing up for pre-authorized payment, reporting a payment, signing up for pre-authorized payment, changing your mailing address, agreement to disconnect service between tenants, third-party authorizations, report a water meter reading and customer feedback."

Q17b. "Do you presently use, or have you used, our self-serve options?"



Two-thirds of customers said they have used or are using self serve options. This includes 66% of those in Stratford, 69% outside of Stratford, 66% of residents and 73% of businesses.

Q17c. "What other self-serve options would you like to see on our website?"

Unsure / none	56%
Report a power outage	26%
Report a billing discrepancy	16%
Request a service layout	2%
Energy efficiency / how to save	1%
Green house gas emissions	1%

While a majority or 56% were unsure of what other self serve options they would like or said none, those with opinions most named reporting outages and billing discrepancies.

Environmental Controls

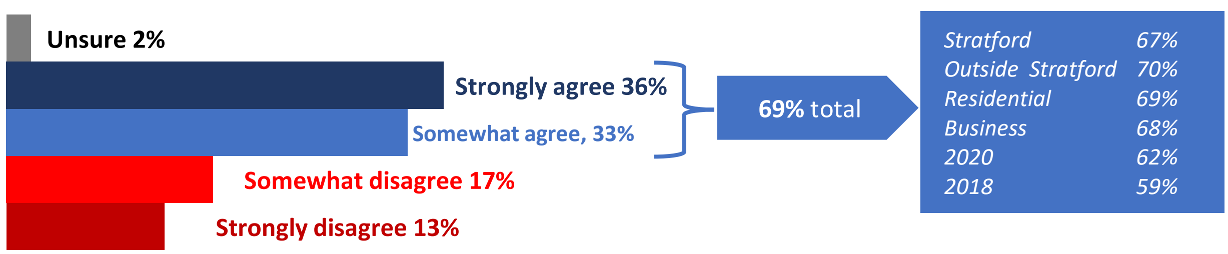
The next two questions asked customers about the electricity system in Ontario, including cost and being well served.

"The next two questions are about the electricity system in Ontario. For each statement I read, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with them."

FINANCIAL CIRCUMSTANCES

RESIDENTIAL Q18. "The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities."

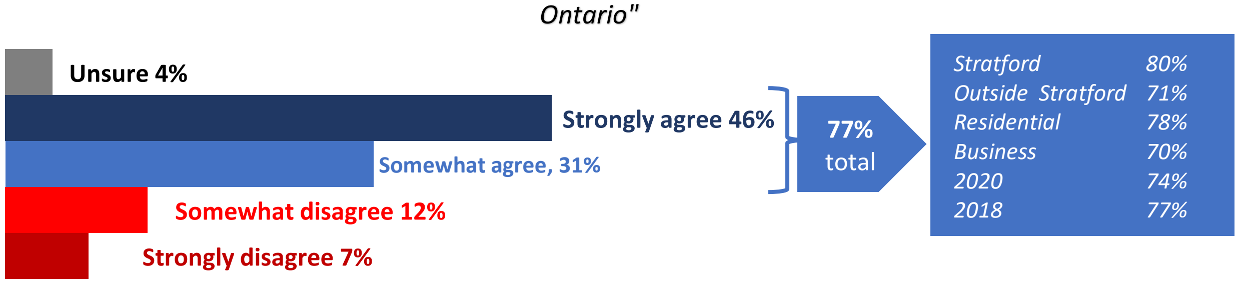
BUSINESS Q18. "The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off."



There was an increase of+7% to 69% in the number of customers that agreed the cost of their bill has impacted other priorities.

SYSTEM PERFORMANCE

Q19. "Customers are well served by the electricity system in Ontario"



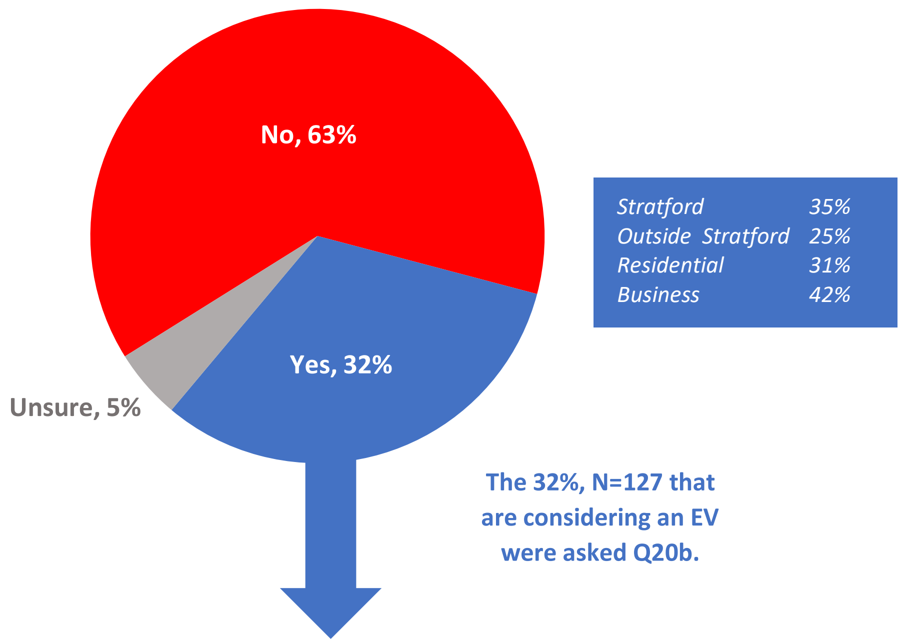
More agreed (+3% over 2020) that customers are well served by the electricity system in Ontario, with residents and those living in Stratford having the highest agreement scores.

Electric Vehicles

The final two questions were about electric vehicles. In the first, all respondents were asked if they were considering an EV and if they were, a follow-up question about timelines was asked.

"The final two questions relate to electric vehicles."

Q20a. " Is your business/household considering an electric vehicle?"



Q20b." What timeframe are you considering adding an Electric Vehicle to your home / business?"

0-1 years	34%
1-2 years	20%
3-5 years	33%
5+ years	6%
Unsure	7%

Thirty-two percent are considering an EV purchase, especially businesses and those living in Stratford. More than half are thinking of buying a vehicle over the next two years and 87% within the next five.

Attachment 1 – 9

Public Awareness of Electrical

Safety Scorecard

INNOVATIVE RESEARCH GROUP

Survey Results

Public Awareness of Electrical Safety Scorecard

Festival Hydro Inc.

March 22, 2022

STRICTLY CONFIDENTIAL

Key Findings

In order to gauge overall electrical safety awareness amongst the general public, six core questions were developed in 2015, via a province-wide industry consultation led by the Electrical Safety Authority (ESA) and Innovative Research Group (INNOVATIVE), and ultimately approve by the Ontario Energy Board (OEB).

An index score was applied to each response, where "*best answers*" received a score of 1 and "*incorrect answers*" received a score of zero. Outlined below and on the Safety Awareness Dashboard are the percentage of respondents that selected the "*best answer*" for each of the six core questions.

- **Likelihood to call before you dig:** Half of respondents (48%) would definitely call before digging.
- **Impact of touching a power line:** Almost all respondents (91%) think touching a power line is "very dangerous".
- **Proximity to overhead power line:** 1-in-5 respondents (20%) believe they should maintain a distance of 3 to 6 metres. A plurality (38%) believe they should maintain a distance of 6 metres or more.
- **Danger of tampering with electrical equipment:** Almost 9-in-10 respondents (87%) believe tampering with equipment is "very dangerous".
- **Proximity to downed power line:** 3-in-5 (61%) believe they should maintain a distance of 10 metres or more.
- **Actions taken in vehicle in contact with wires:** Nearly all respondents (91%) believe they should stay in the vehicle until power has been disconnected from the line.

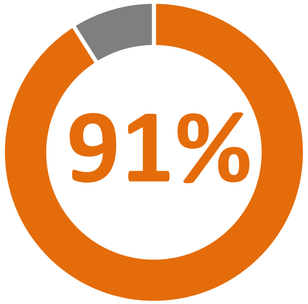
Festival Hydro has an overall score of 77% on the Public Safety Awareness Index (down slightly from 2020 at 80%).

- **Highest at risk groups:** Those who are not aware of the type of electricity service at their residence (67% score) and those who reside in a farm or not in a house or condo (66% score) have the lowest Overall Safety Awareness Index score. Women aged 18-34 are more susceptible to incorrectly answering the question regarding what to do when a live wire is on your vehicle.
- **Lowest at risk groups:** Women 35-54 (84% score) have the highest Safety Awareness Index score. Following behind are those who live in a semi-detached house (80% score), those who live in an apartment or condo (79%) and those who receive electricity via overhead wires (79% score).

2022 Safety Awareness Dashboard

20%

Believe you should maintain ***3 to 6 metres*** from an overhead powerline



Say it's
Very dangerous
to touch an overhead power line

48% Would ***definitely*** call before digging

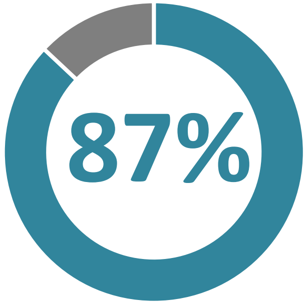
Overall Public Safety Awareness Index Score

77%

91%

Believe it's ***safer to stay in the vehicle*** in case of a downed power line

Say it's
Very dangerous
to tamper with electrical equipment



61%

Believe you should maintain ***10 metres or more*** from downed power line

Note: values indicate percentage of respondents who selected the *best answer* to scored questions in the *Public Awareness of Electrical Safety Scorecard* survey.

Methodology

Innovative Research Group (INNOVATIVE) was commissioned by **Festival Hydro** to conduct its 2022 *Public Awareness of Electrical Safety Scorecard* survey as required by the Ontario Energy Board (OEB).

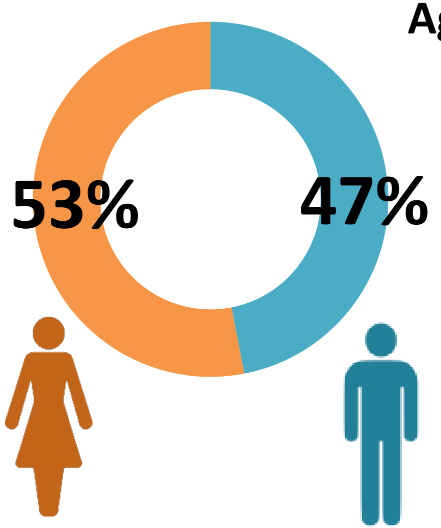
- This survey was conducted by telephone among **408** randomly-selected Ontario residents, 18 years or older, currently residing in **Stratford, Brussels, Dashwood Hensall, St. Marys, Seaforth, or Zurich,** between March 1st and March 11th, 2022.
- Respondents did not need to be Festival Hydro customers to qualify for this survey. The OEB's standardized methodology defines qualified respondents as adults who principally reside in the LDC's service territory, regardless of whether they are customers or not.
- Both cell phones and landlines are included in the sample to ensure that those who do not have a landline phone are represented in the final sample.
- The sample has been weighted to **n=400** by age, gender and region using the latest Statistics Canada Census data to reflect the actual demographic composition of the adult population residing in the **Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, and Zurich**.
- This survey is a tracking survey. The results from this year have been compared to the 2020 and 2016 Public Awareness of Electrical Safety Scorecard survey. The 2020 survey was conducted among 403 randomly-selected Ontario residents, 18 years or older, residing in the aforementioned regions, between March 2nd and March 16th, 2020. The 2018 survey was conducted among 415 randomly-selected Ontario residents, 18 years or older, residing in the aforementioned regions, between March 6th and March 11th, 2018. The 2016 survey was conducted among 400 randomly-select Ontario residents, 18 years or older, residing in the aforementioned regions, between March 1st and March 5th, 2016.
- After weighting a sample of this size, the aggregated results are considered accurate to within **±4.9%**, 19 times out of 20.
- The margin of error will be larger within each sub-grouping of the sample.

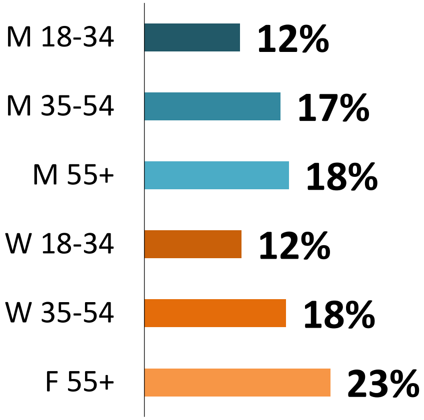
Note: *Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

Demographics

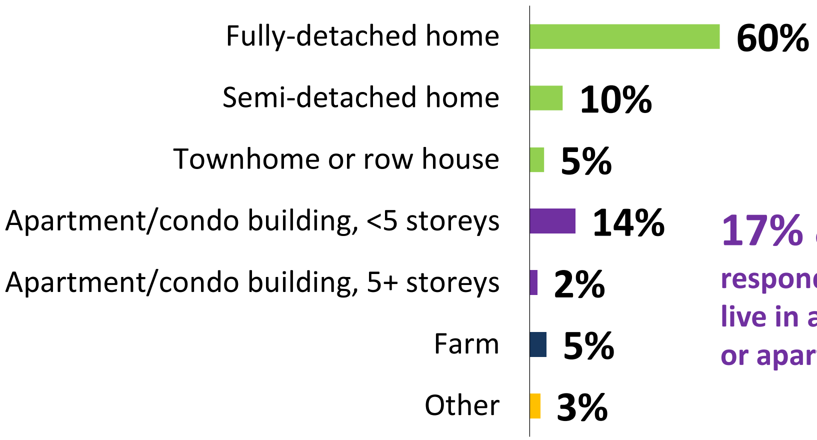
Respondent Profile

Age-Gender



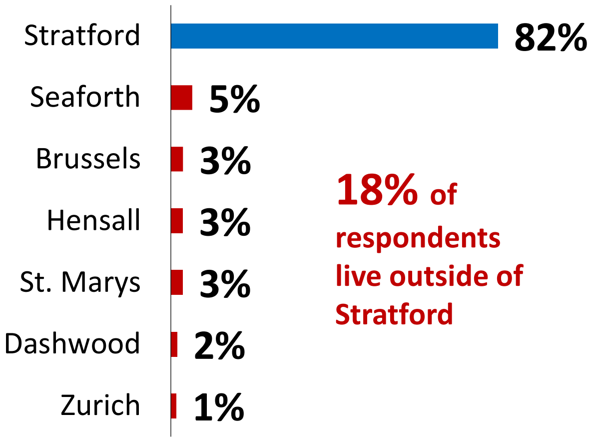


Primary Residence



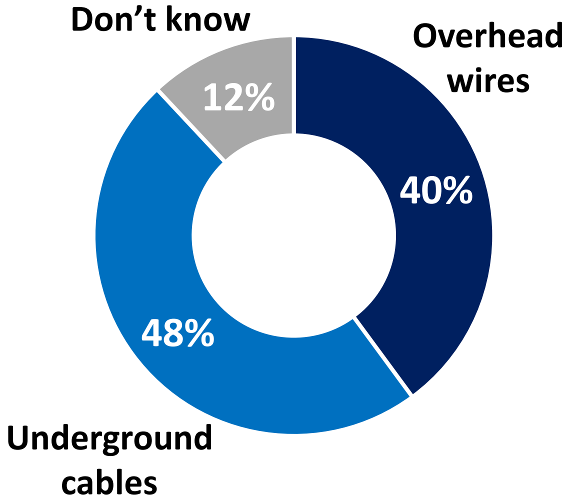
17% of respondents live in a condo or apartment

Region

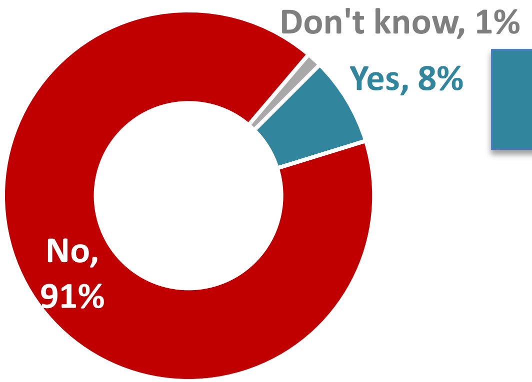


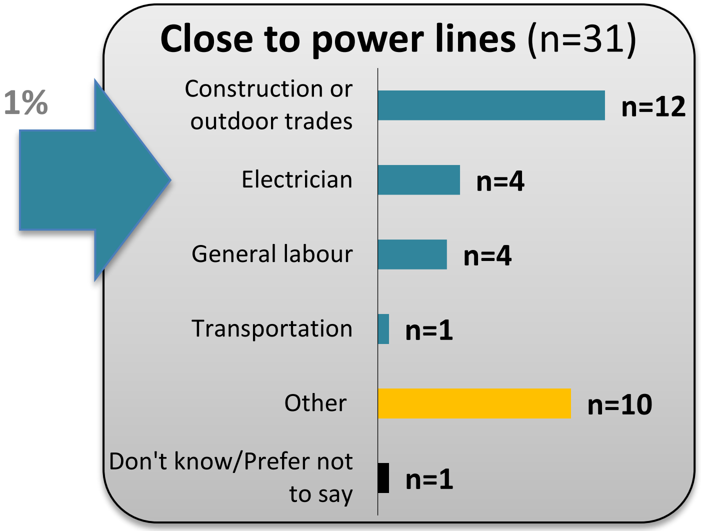
18% of respondents live outside of Stratford

Does your primary residence receive electricity through …



Does your job regularly cause you to come close to energized power lines?





Awareness of Electrical Safety

INNOVATIVE
RESEARCH GROUP

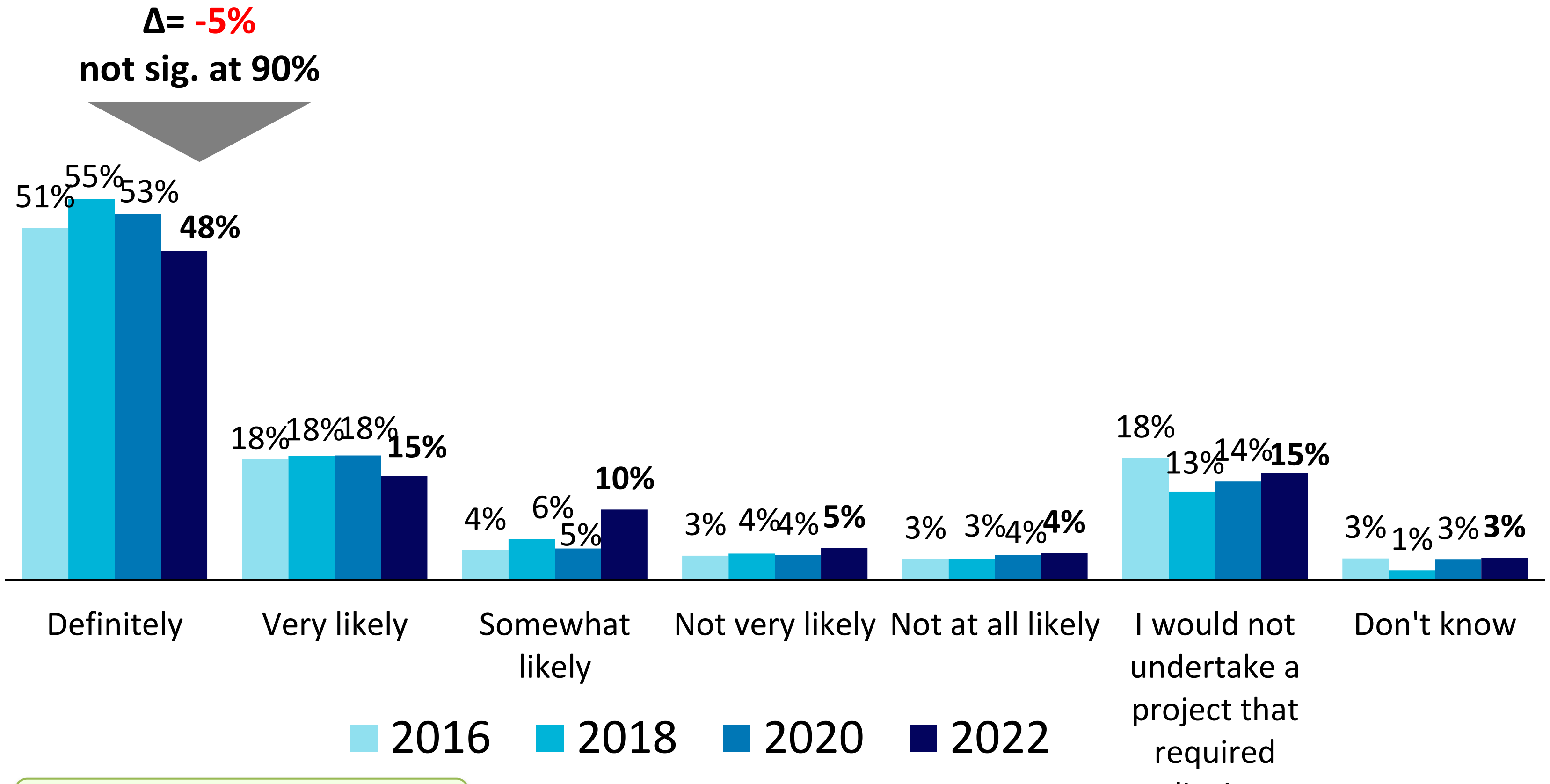
Likelihood to Call Before You Dig

Less than half (48%) of respondents would 'definitely' call; highest among women aged 35-54 (71%)

Q

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

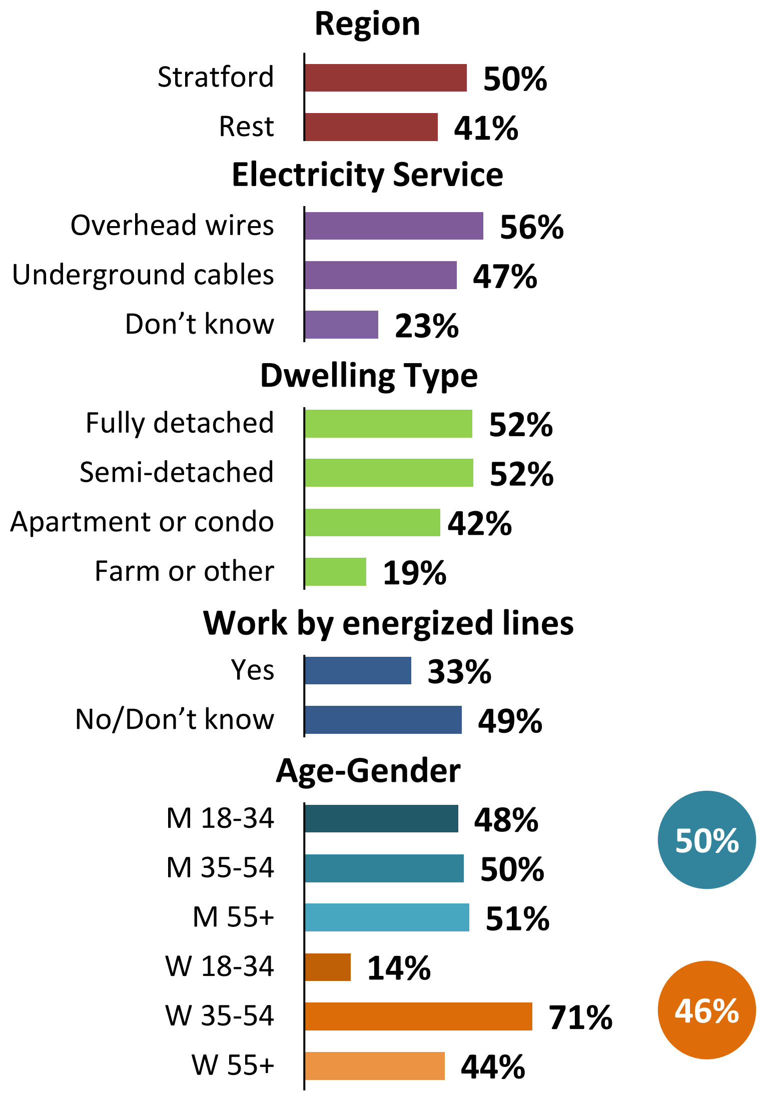
[asked of all respondents, n=400]



Best Answer: *Definitely*

2022 Segmentation

Respondents who say "Definitely" **[BEST ANSWER]**

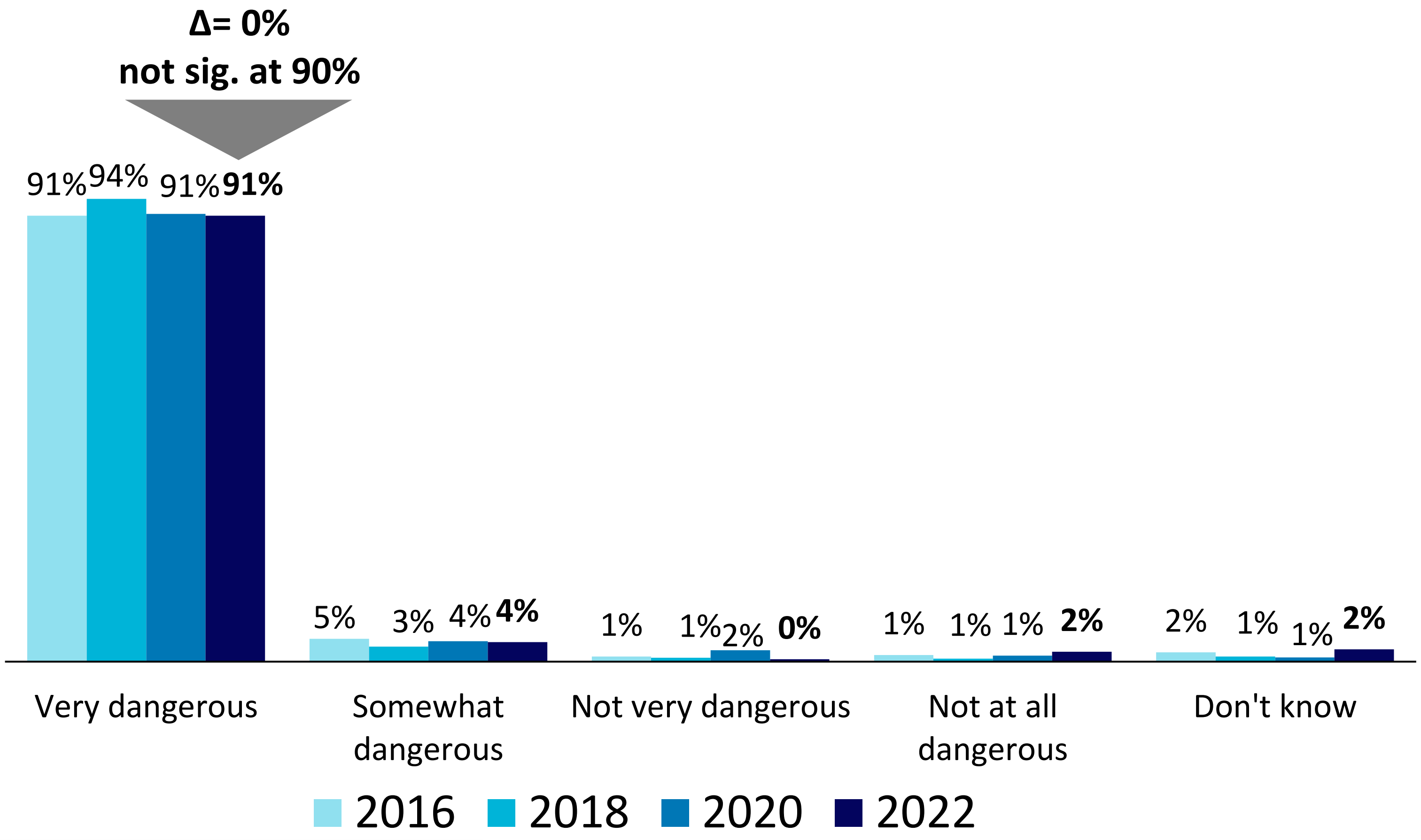


Impact of Touching a Power Line

Almost all (91%) say 'very dangerous'; lowest among those who work by energized lines and men aged 18-34

Q How dangerous do you believe it is to touch - with your body or any object - an overhead power line?

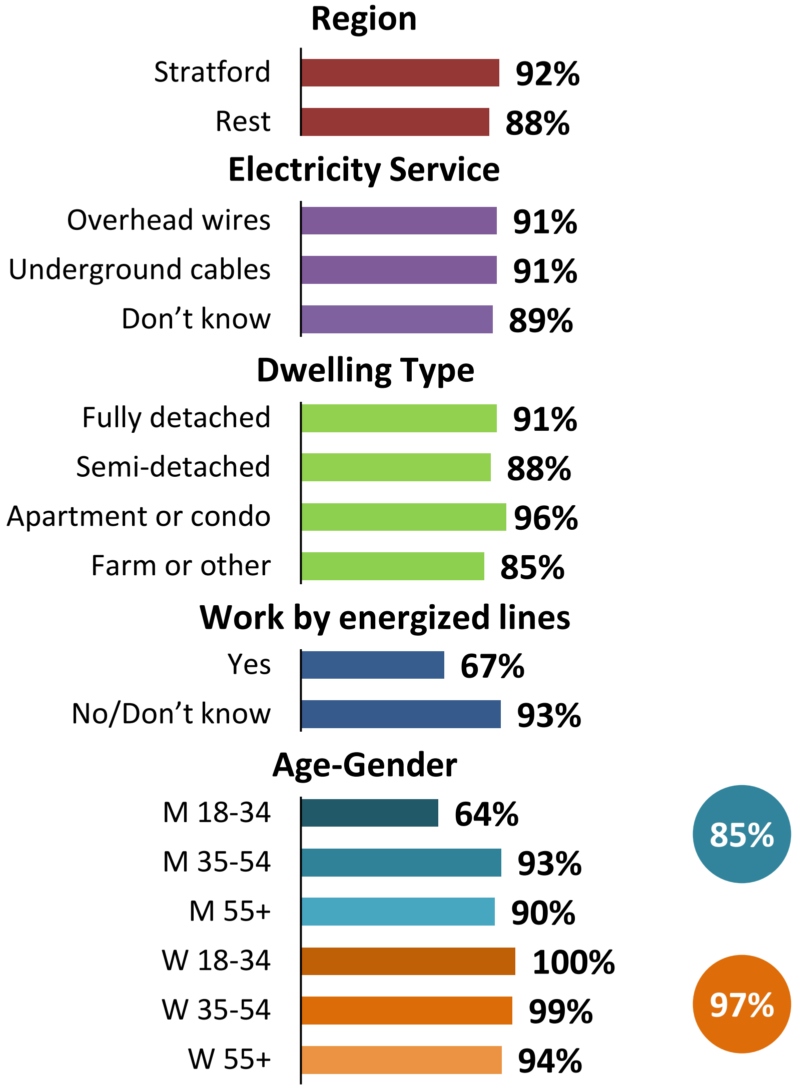
[asked of all respondents, n=400]



Best Answer: *Very Dangerous*

2022 Segmentation

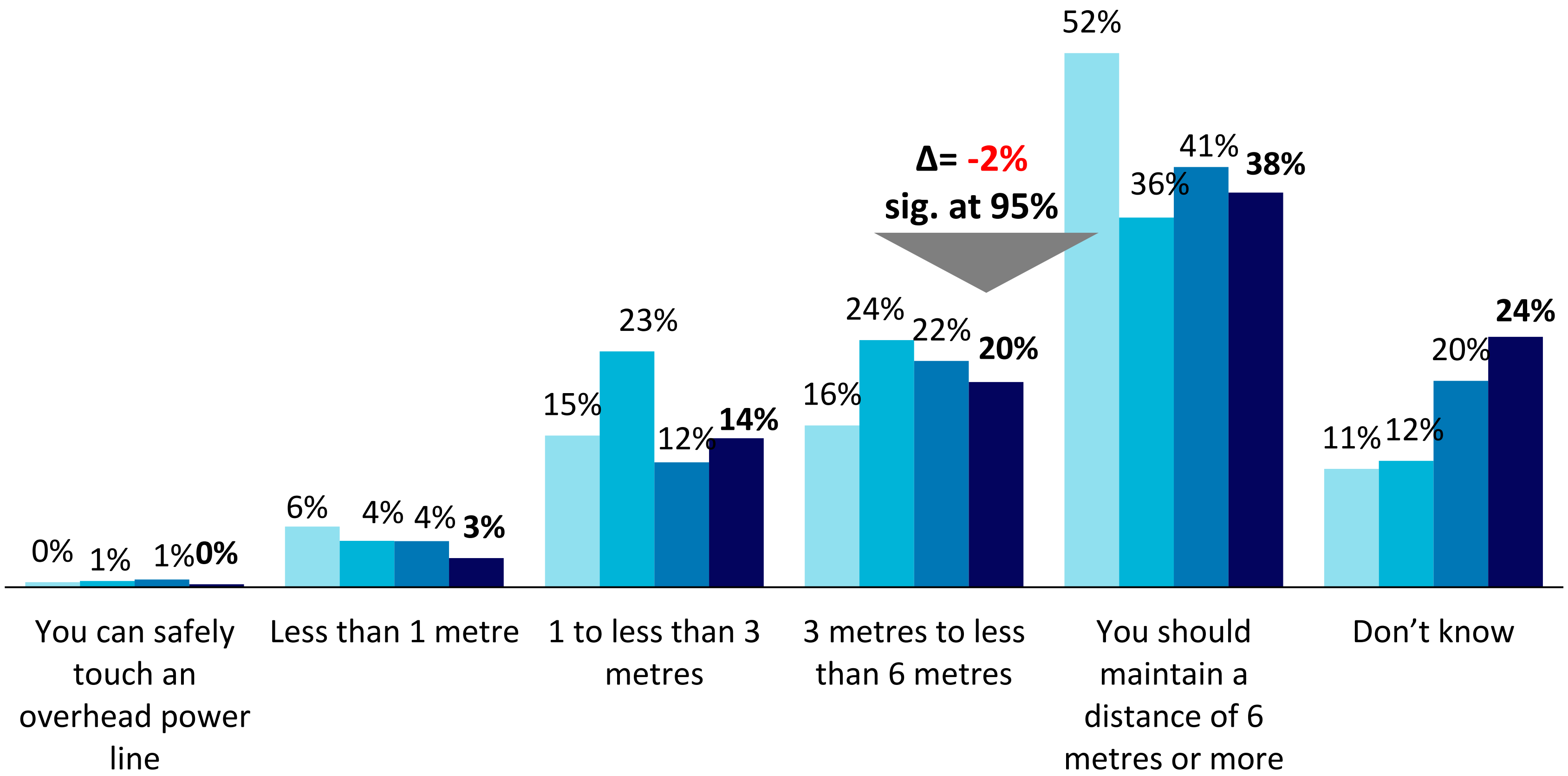
Respondents who say "Very Dangerous" **[BEST ANSWER]**



Proximity to Overhead Powerline

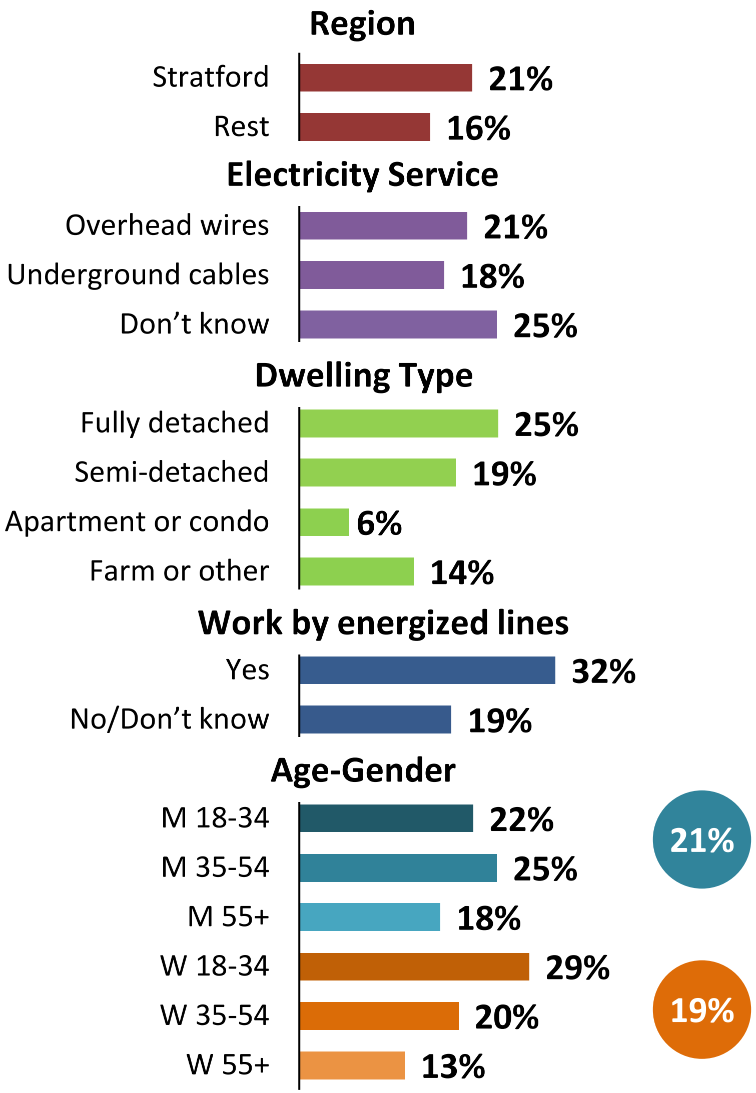
1-in-5 (20%) say ‘3 to less than 6 meters’ is safe; highest among those who work by energized lines (32%)

Q When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how closely do you believe you can safely come to an overhead power line with your body or an object?
[asked of all respondents, n=400]



Best Answer: *3 metres to less than 6 metres*

2022 Segmentation
Respondents who say “3m to <6m” **[BEST ANSWER]**



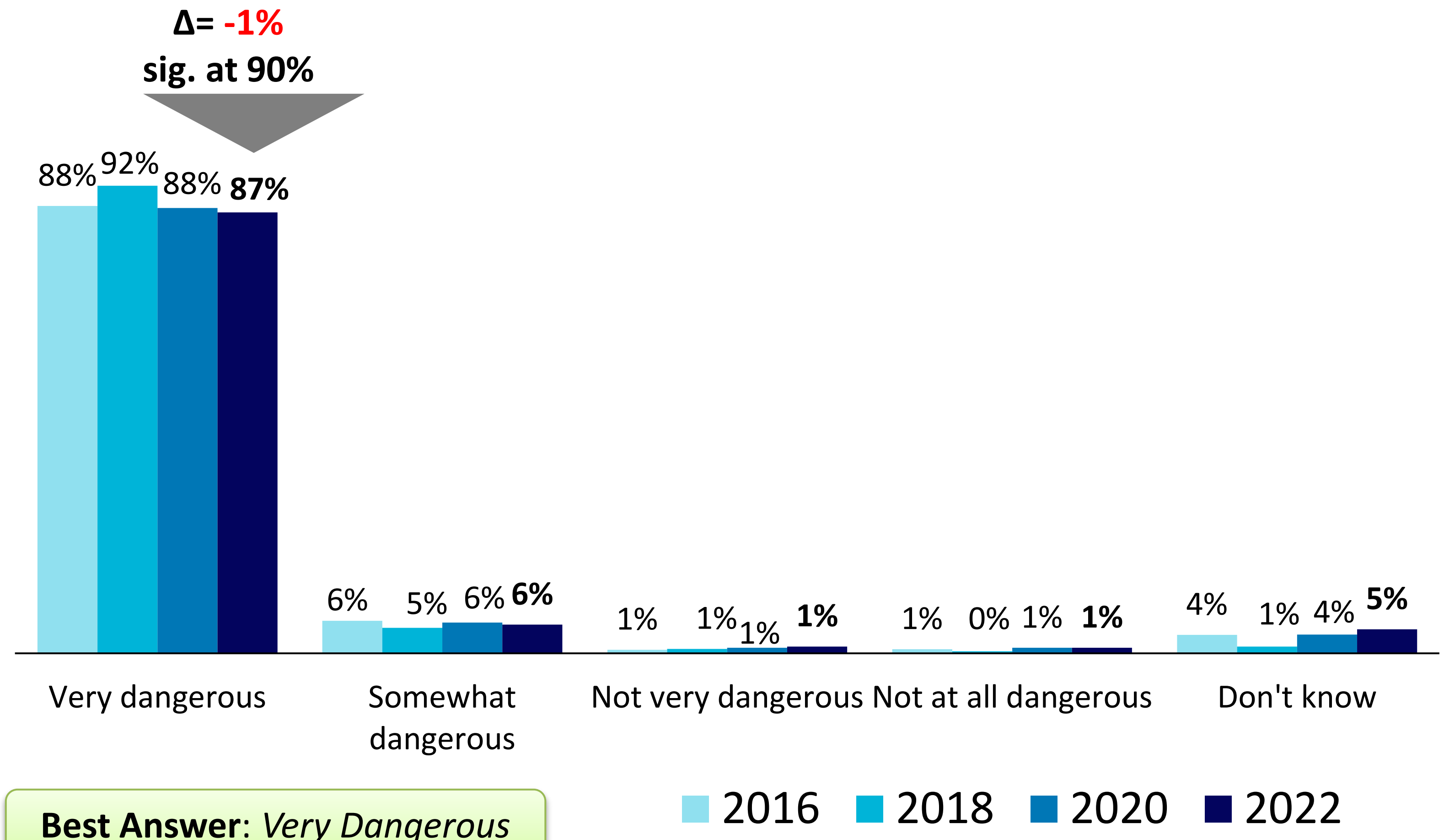
Danger of Tampering with Equipment

Over 4-in-5 (87%) chose 'very dangerous'; highest among middle aged men (96%) and women (91%)

Q

Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers. How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside?

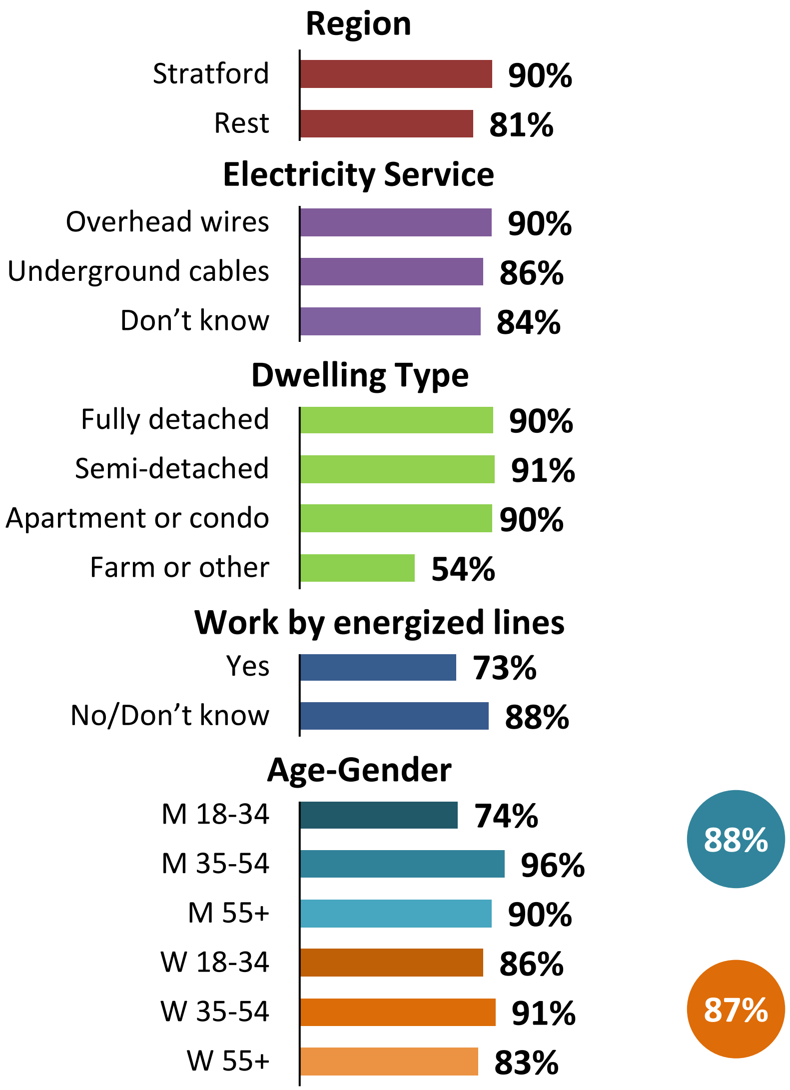
[asked of all respondents, n=400]



Best Answer: *Very Dangerous*

2022 Segmentation

Respondents who say "Very Dangerous" **[BEST ANSWER]**

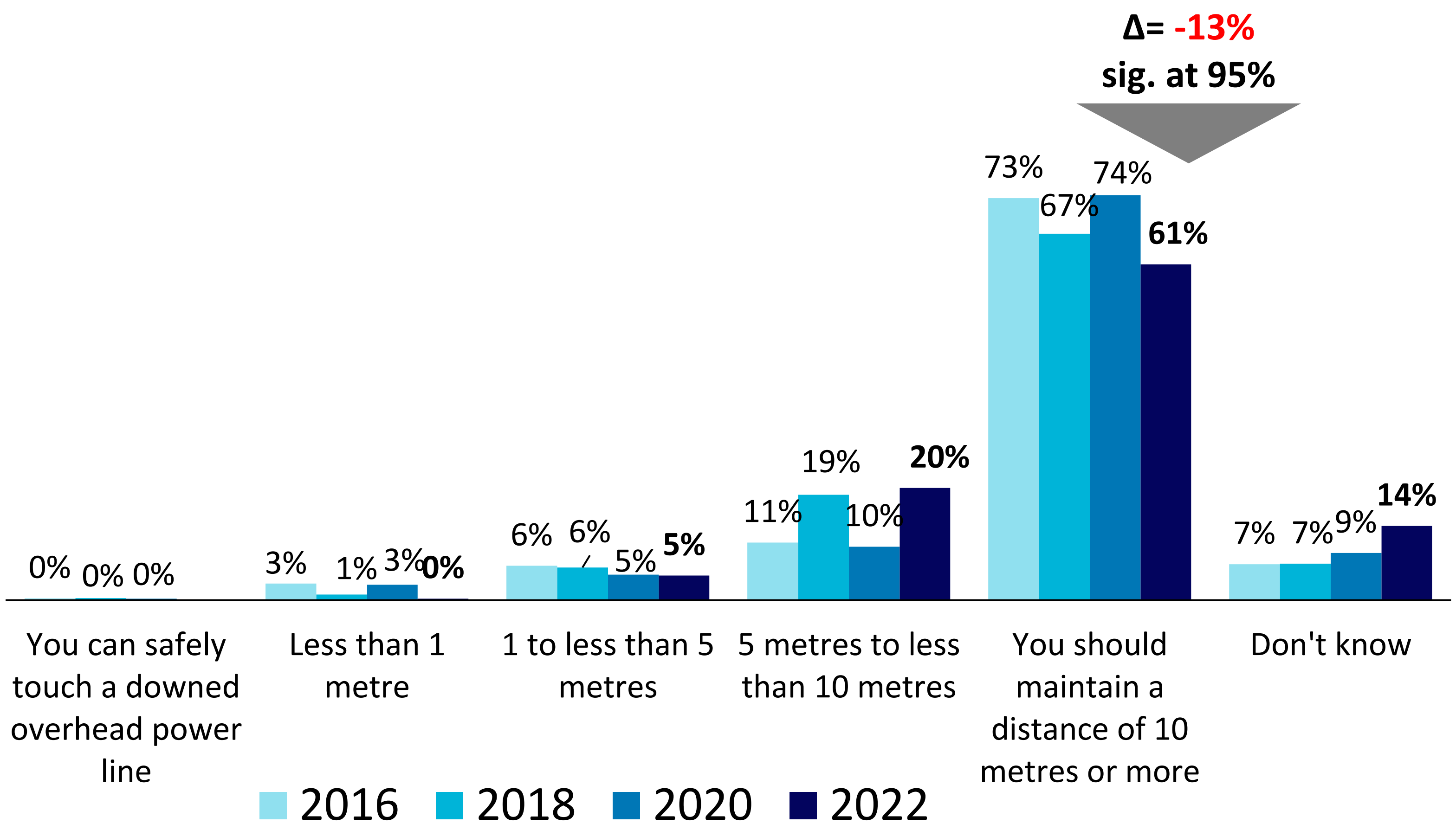


Proximity to Downed Power Line

3-in-5 (61%) say '10 meters or more', dropped 13 pts since 2020; lowest among younger women (29%)

Q How closely do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident?

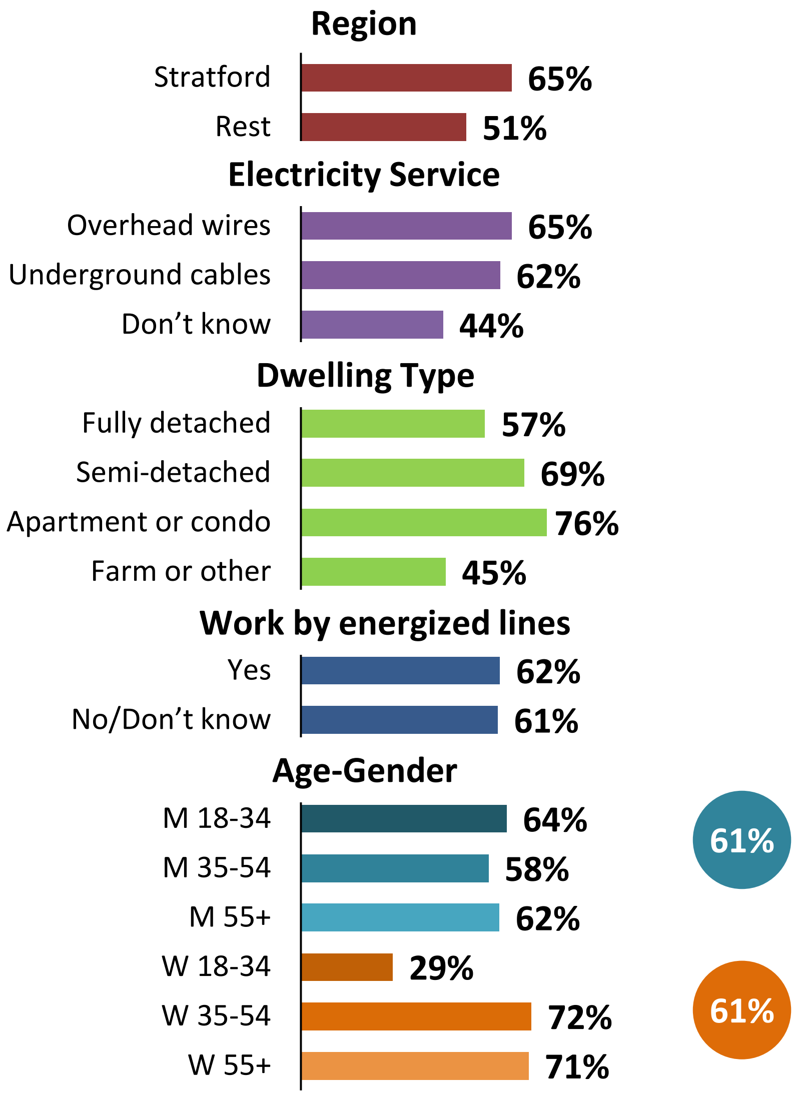
[asked of all respondents, n=400]



Best Answer: *You should maintain a distance of 10 metres or more*

2022 Segmentation

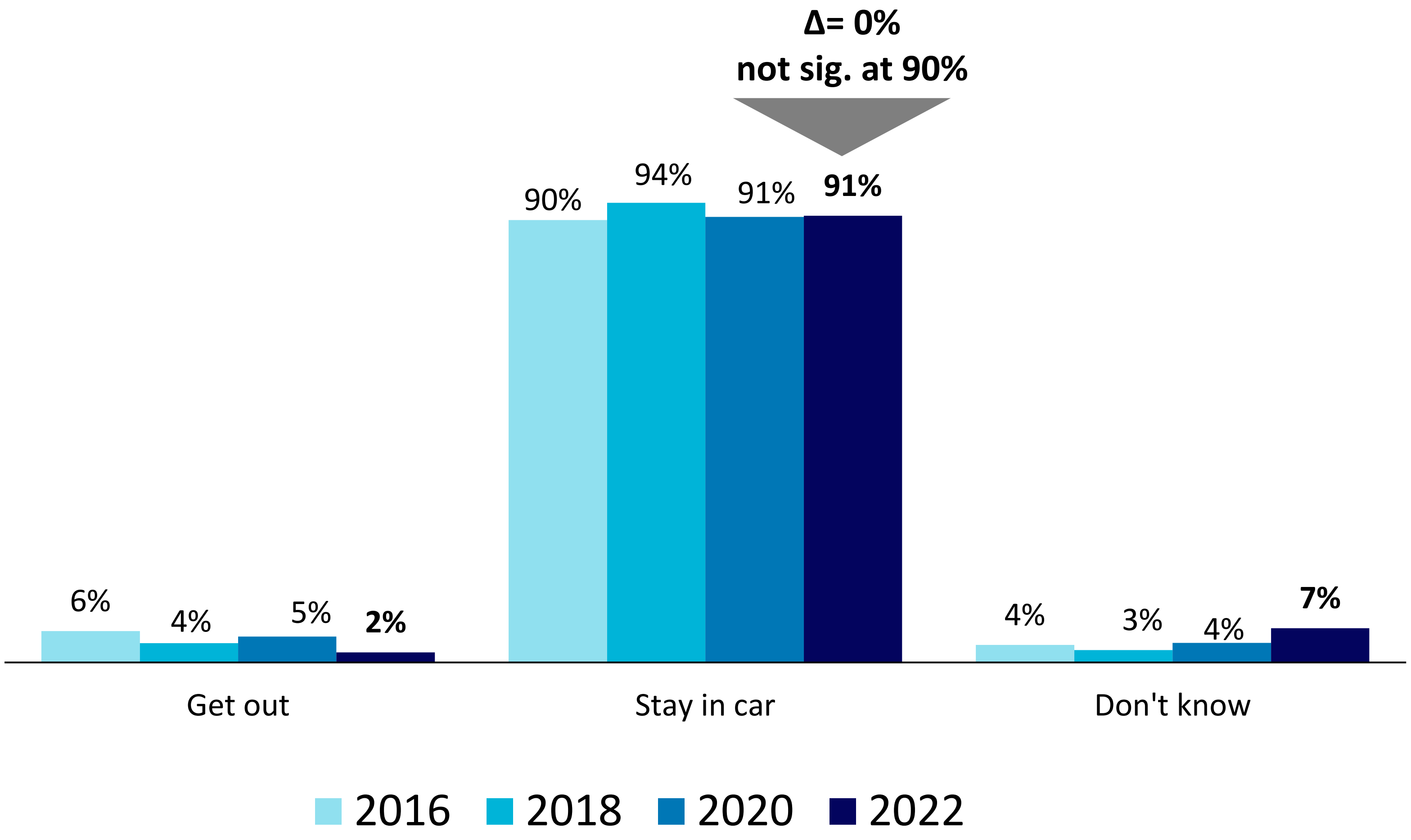
Respondents who say "10m+" **[BEST ANSWER]**



Actions Taken in Vehicle in Contact with Wires

Over 4-in-5 (91%) say 'stay in car'; results are steady since 2016

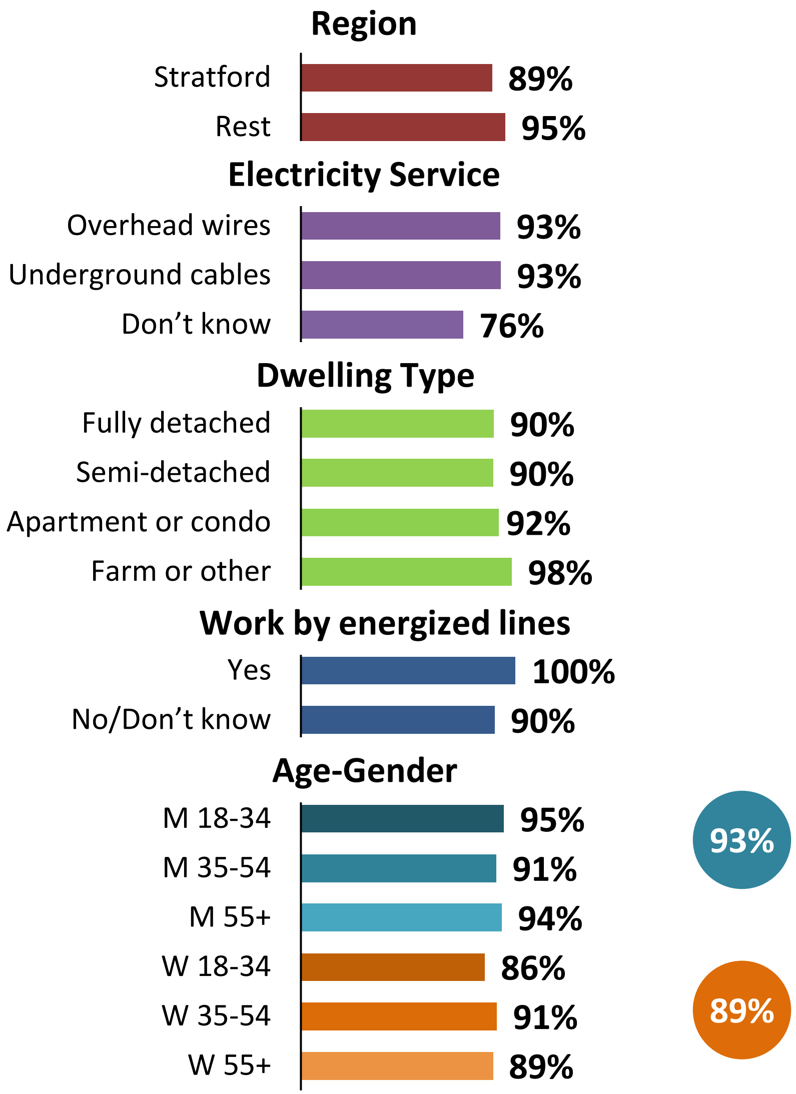
Q If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?
[asked of all respondents, n=400]



Best Answer: *Stay in the vehicle until power has been disconnected from the line*

2022 Segmentation

Respondents who say "Stay in vehicle" **[BEST ANSWER]**



Actions Taken by Age-Gender

Women aged 18-34 are least likely to choose ‘stay in the vehicle’ and are most likely to be unsure

Q

If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

[asked of all respondents, n=400]

Action Taken	Total	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+
Get out quickly and seek help	**2%**	**-**	**2%**	**4%**	**-**	**3%**	**2%**
Stay in the vehicle until power has been disconnected from the line	**91%**	**95%**	**91%**	**94%**	**86%**	**91%**	**89%**
Don’t know	**7%**	**5%**	**7%**	**2%**	**14%**	**6%**	**9%**

Best Answer: *Stay in the vehicle until power has been disconnected from the line*

INNOVATIVE RESEARCH GROUP

Overall Safety Awareness Score

Calculating the Public Safety Awareness Index Score

Each answer to core safety awareness questions will be allocated points based on the accuracy of the response. Responses deemed "*Best Answer*" will be allocated 1 point, while lesser answers will be awarded progressively less points. Responses are then indexed to create a single comparable Public Safety Awareness Score.

All section points bound between 0 and 1

Likelihood to *call before you dig*	0 to 1pts
Impact of touching a power line	0 to 1pts
Proximity to overhead power line	0 to 1pts
Danger of tampering with electrical equipment	0 to 1pts
Proximity to downed power line	0 to 1pts
Actions taken in vehicle in contact with wires	0 to 1pts

Add all 6 section points among survey respondents

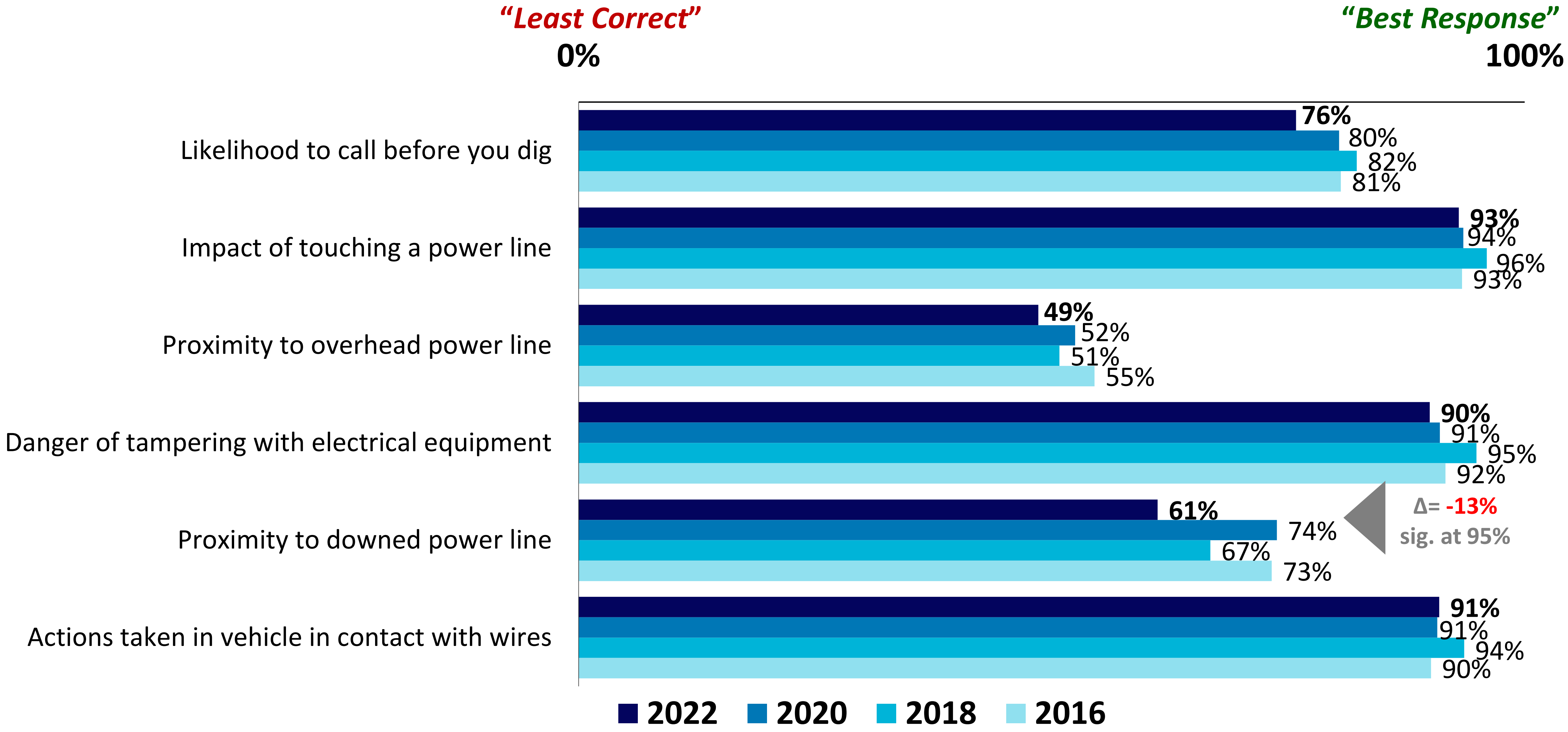
Divide score sections and survey sample size.

Multiply score by 100.

LDC Public Safety Awareness score bound between 0-100%

Calculating the Public Safety Awareness Index Score

Below are the individual index scores for each of the six core electrical safety questions. Each response has been rewarded a score between 0 and 1 based on what has been deemed the "best response".



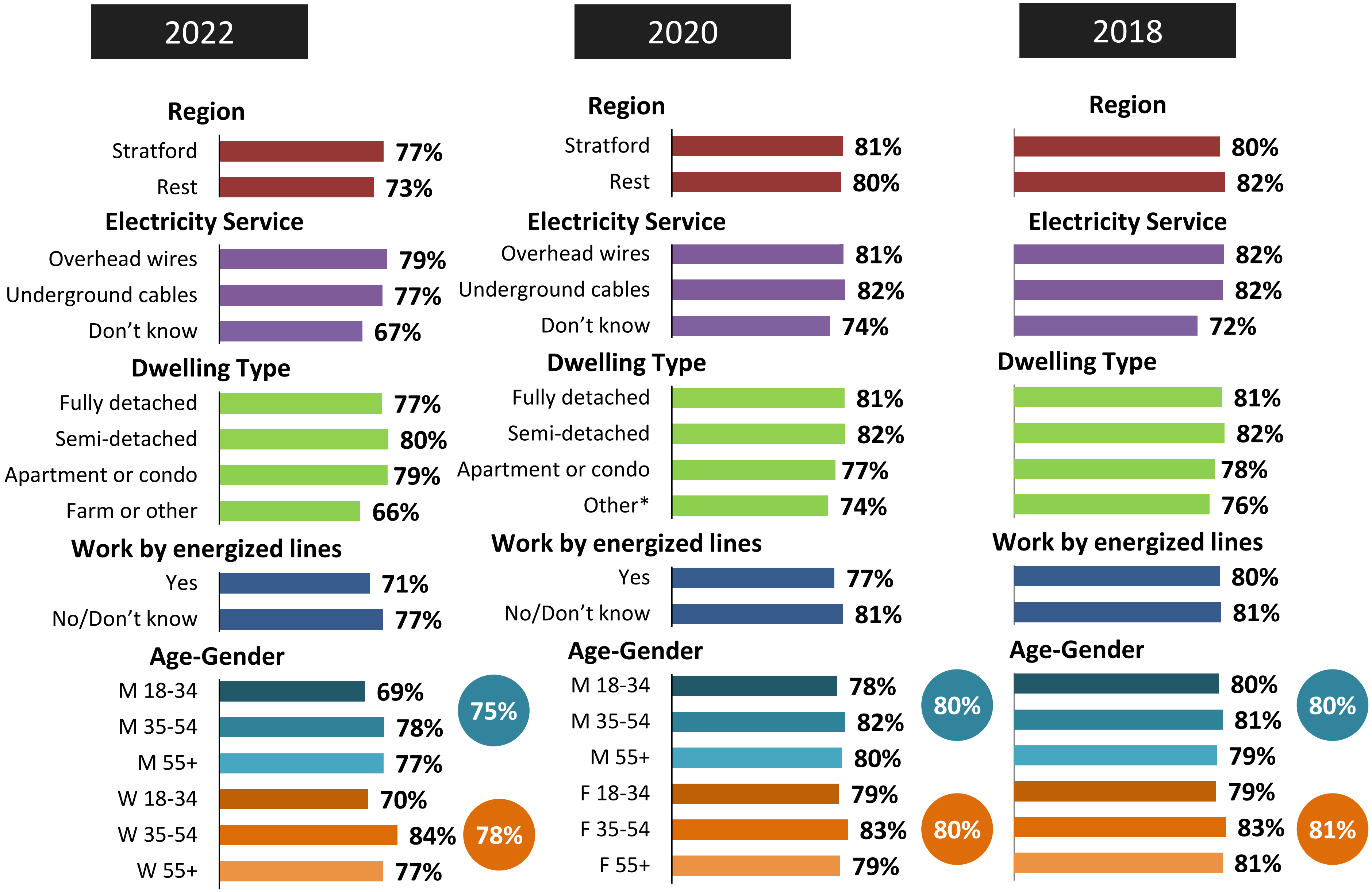
Festival Hydro Inc.

2022 Safety Awareness Score

77%

Historical Scores

80% in 2020
81% in 2018
80% in 2016



* Due to small n size (n<30), results should be treated with caution.

Building Understanding.

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Martha Villarreal Lopez, Analyst

Attachment 1 –10

Customer Engagement Survey

Festival Hydro

2023 Customer Engagement Survey Report

BRICKWORKS

COMMUNICATIONS

June 2023

Table of Contents

Background & Overview	3
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Tree Trimming	8
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Communication	10

Background & Overview

Festival Hydro commissioned Brickworks to conduct an engagement survey of its customers. The purpose of this survey process was to obtain customer input regarding their needs and preferences with the services provided by Festival Hydro to be used for the Cost of Service Application.

Brickworks and Festival Hydro designed the questionnaire. This word report contains an executive overview of the findings, while a separate report in Excel includes the results by each question.

Methodology & Logistics

Study Sample

All surveys were completed online using Computer Assisted Web Interviewing (CAWI). This was an open-online self-selection survey where respondents could connect with the survey link to complete their interview.

This is not a random sample poll based on a scientific representative sample of a defined audience.

Survey Method

All surveys were completed online using Computer Assisted Telephone Interviewing (CATI). The survey was promoted by Brickworks and Festival Hydro through its resources.

Logistics

The survey was open, and questionnaires were completed between the days of May 18 and June 2nd, 2023.

Confidence

It is not acceptable to assign online self-selection non-probability surveys a margin of error. However, a probability sample of this nature would be considered accurate ± 1.6%, 19/20 times.

Customer Preference Priorities

The following descriptive preamble was first presented to customers. They were then asked in the first question to rank in order a series of five option areas.

We are creating our business plan as part of our Cost-of-Service Rate Application for the Ontario Energy Board. As part of the process, we are reaching out to customers for their opinion as to what priorities and outcomes our 2025 capital and operating plans should focus on. We are seeking customer feedback about whether we have found the right balance between reliability, customer service, innovation, and the price you pay for electricity, or if they should consider different options.

Management has reviewed each part of Festival Hydro's business and the projects and topics identified in this survey have been recognized as providing meaningful benefits. However, their pace of implementation and timing can potentially have an impact on the overall reliability and state of the distribution system as well as the current rates customers are charged.

The survey should take less than 5 minutes. In appreciation of completing this survey, if you leave your contact information, you will be entered into a draw for 1 of 3 $100 VISA gift cards.

Q1. Based on these five options, rank each from one to five with one being most important and five being least important to you.

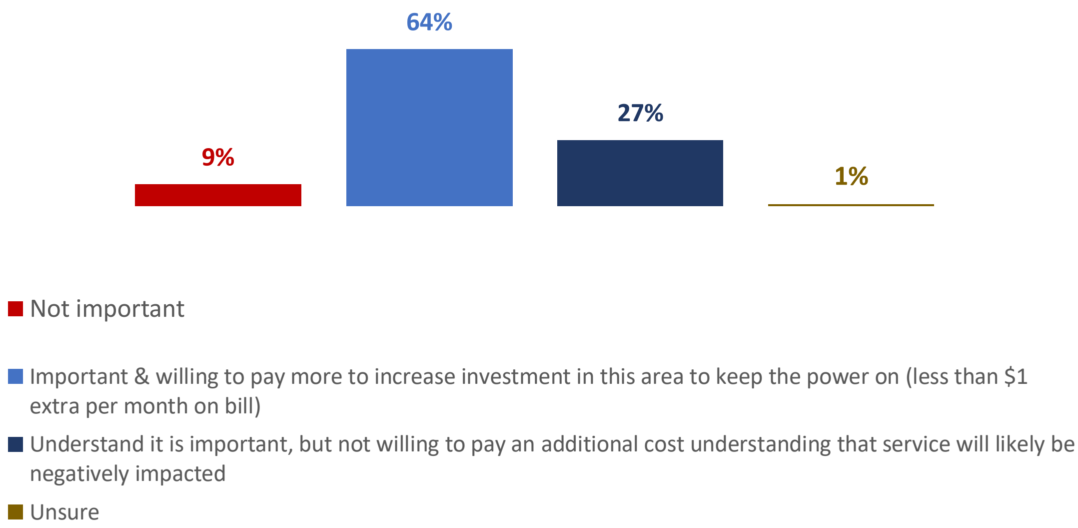
Mean Score 1-Most Important & 5- Least Important	*Mean*
Q1A. Festival Hydro provides electricity that is "reliable" and "safe" (fewer outages and focuses on public and employee safety)	2.73
Q1B. Festival Hydro prioritizes aesthetics over most cost-effective solution when constructing or replacing assets at an increased cost to customers (things such as moving overhead wires underground, and moving rear lot infrastructure to front of property)	2.83
Q1C. Festival Hydro provides electricity at low cost at the expense of reliability, green initiatives, innovation and customer service.	2.88
Q1D. Festival Hydro invests in innovative solutions such as smart grid, battery storage, electric vehicle infrastructure, solar and smart home technologies at an increased cost to customers.	3.22
Q1E. Festival Hydro provides excellent customer service	3.33

Highest ranked in terms of importance with a mean score pf 2.73 is providing electricity that is "reliable" and "safe" with fewer outages, focusing on public and employee safety. The next two mid-scored areas that ranked closely together were prioritizing aesthetics over most cost-effective solutions when constructing or replacing assets at 2.83 and then providing electricity at a low cost at the expense of reliability, green initiatives, innovation and customer service at 2.88. The two lowest ranked issues in terms of priority were investing in innovative solutions at 3.22 and for providing excellent customer service at 3.33.

Power Outages

Respondents were then asked about the importance of minimizing power outages. They were presented with three options to choose from.

Q2. Festival Hydro strives to always keep the power on. However, there are occasions (ex. due to storms, vehicles accidents and equipment failure) when we experience a power outage. On average, power is out 13 minutes per month per customer. How important

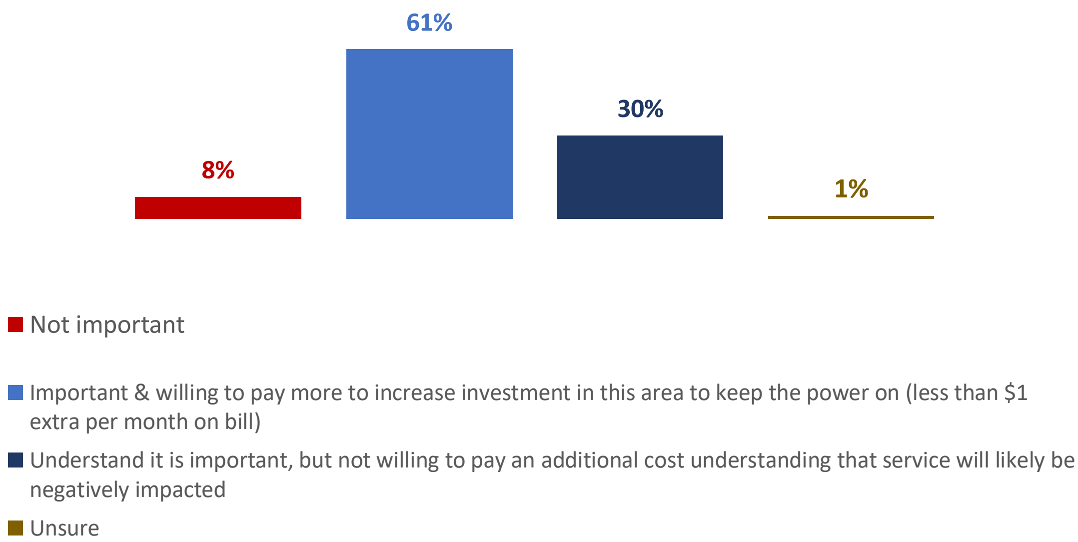


With respect to minimizing power outages, more than six in ten or 64% said it is important and that they are willing to pay more to increase investments to keep the power on, paying less than $1 extra per month on their bill. More than a quarter or 27% understand it is important but are not willing to pay any more each month – this despite service that may be impacted. Only 9% claimed that this is not an important issue, while 1% did not know.

Smart Grid

A definition of a smart grid was displayed after which respondents were asked how important it is to have these services provided.

Q3. A smart grid senses problems on the power grid and reroutes power automatically, reducing the duration and number of customers impacted by power outages. It can also provide detailed information on outages, such as location of the outage and anticipa

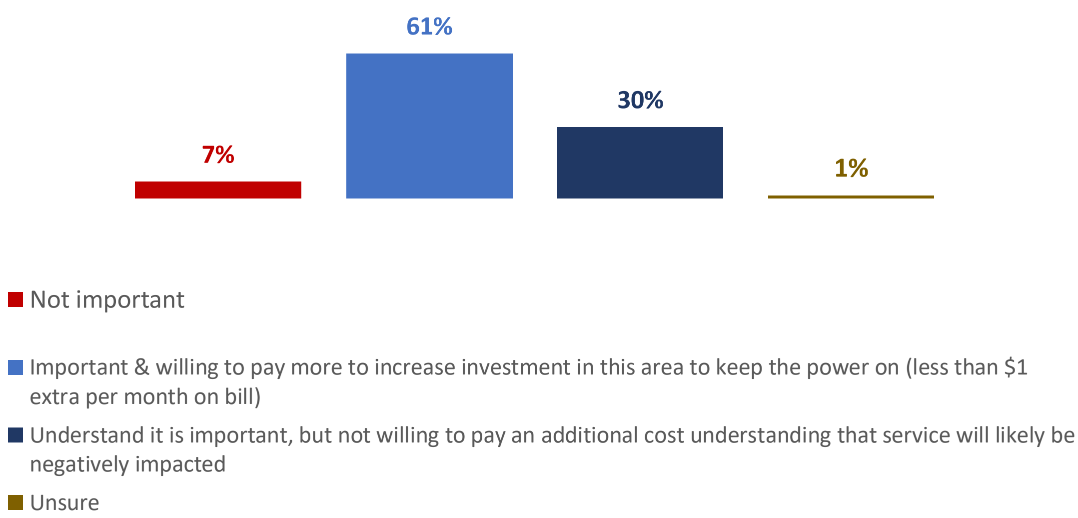


On the issue of smart grids, a 61% majority said they are important, and they would be willing to pay more to increase investments to keep the power on (at less than $1 extra per month on bill). Thirty percent understand their importance but are not willing to pay an additional cost despite understanding that service may be negatively impacted. There were 8% that stated smart grids are not important, while 1% were unsure.

Utility's Assets

Respondents were displayed a statement about the importance of maintaining assets after which they were asked about its importance. They were allowed to choose one of three options including an unsure response.

Q4. Poles, wires, and transformers typically last 40 to 50 years. To ensure an uninterrupted supply of electricity to you, we need to maintain and replace these assets when their useful life has expired. If assets are not replaced on a timely basis, outag

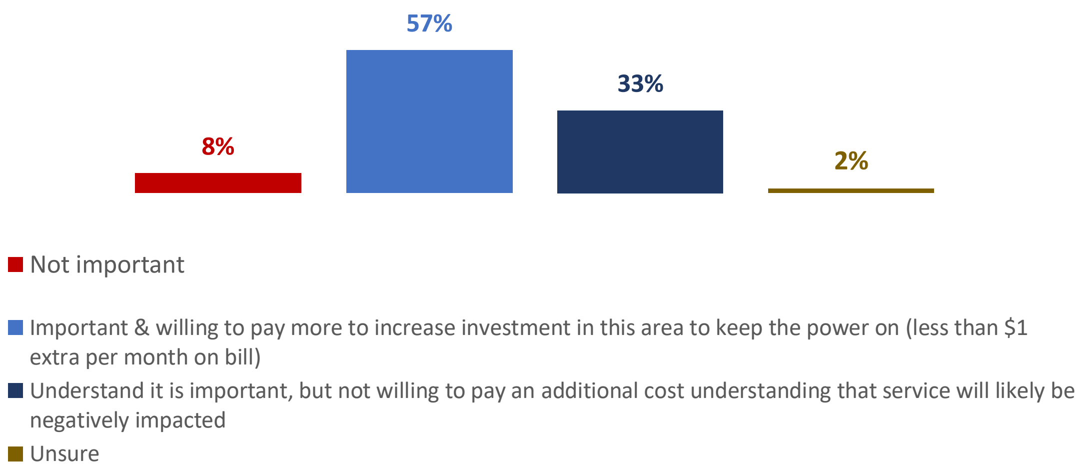


A core 61% claimed that this issue is important and are willing to pay less than $1 on their monthly bill to increase investment in this area. Three in ten while feeling this also important are not willing to pay an additional cost, fully understanding that service will be negatively impacted. The undecideds are at one percent and 7% said this is not important to them.

Tree Trimming

The next area of inquiry was about the importance of tree trimming.

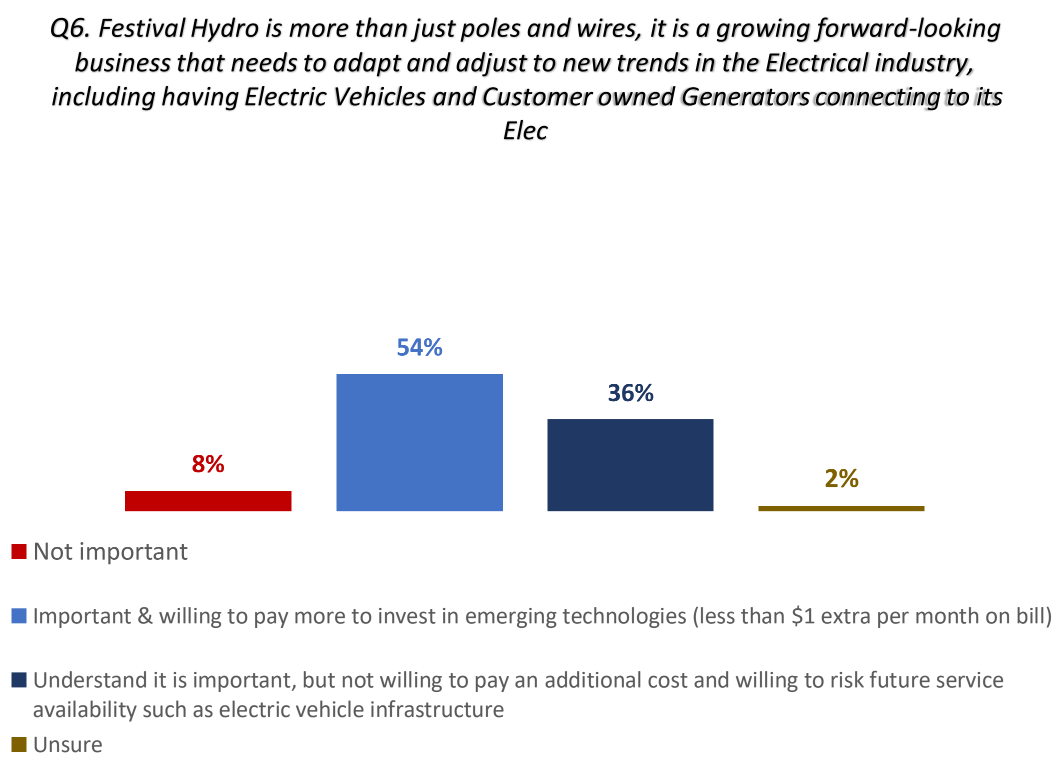
Q5. Festival Hydro provides tree trimming on a cyclical basis to assist with limiting outages from tree contact and animal interference. The cost to perform tree trimming continues to increase annually. How important is maintaining the tree trimming cycle



Tree trimming was deemed important to 57% that would also be willing to pay less than $1 per month to increase investment in this area. One-third while also feeling it important would not be willing to pay additional money despite the risks. A total of 8% felt the issue was not important and 2% were unsure.

New Technologies

Next a preamble was displayed about new technologies and customers were then probed about their importance.

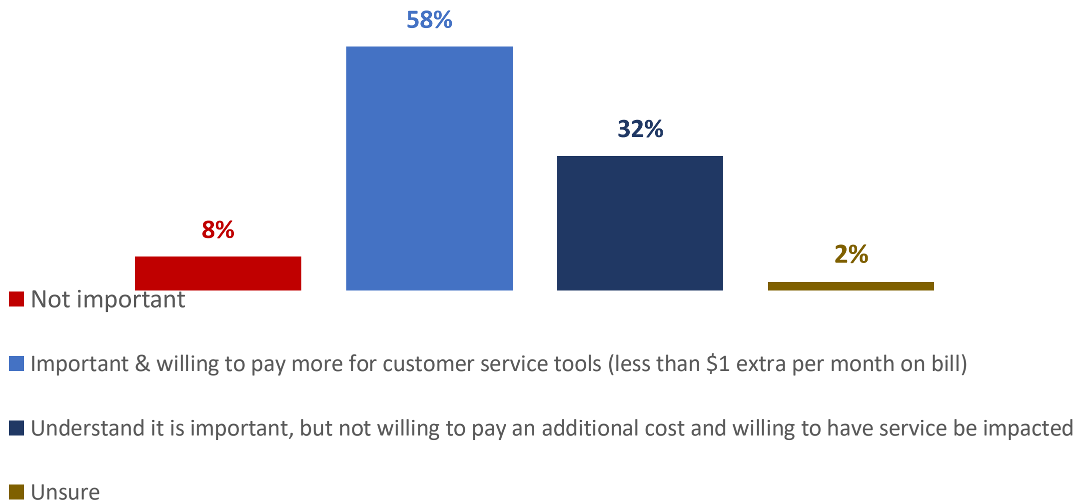


The importance and resulting willingness to pay more to invest in emerging technologies at less than $1 extra per month dropped to 54%, while the percentage of those understanding the importance but not willing to pay increased to 36%. Those saying not important (8%) or being unsure (2%) were constant.

Communication

In the final question, respondents were informed that Festival Hydro is looking to invest in automatic tools and communication methods to improve customer service. They were then asked how important these customer service tools are.

Q7. Festival Hydro is looking to invest in automated tools and communication methods for customer service. Some of these items could include website chat features for customer inquiries, an app that would display usage information and further online forms



The unimportant (8%) and unsure (2%) results remained similar. A total of 58% feel this to be important and are willing to pay $1 more a month for more customer service tools, rules while 32% deeming this also as important are not willing to pay any more.

Festival Hydro

2023 Online
Survey Report

December 2023

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Background & Overview

Festival Hydro commissioned Brickworks Communications to conduct an open-online survey of its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by Festival Hydro.

Brickworks and Festival Hydro designed the questionnaire. This report contains an executive overview of the findings, while a separate report in Excel includes the results by each question.

Methodology & Logistics

Study Sample

All surveys were completed online using Computer Assisted Web Interviewing (CAWI). This was an open-online self-selection survey where respondents could connect with the survey link to complete their interview.

Survey Method

All surveys were completed online using Computer Assisted Telephone Interviewing (CATI). The survey was promoted by Festival Hydro through its resources.

Logistics

The survey was open, and questionnaires were completed between the days of November 22nd and December 11th, 2023.

Confidence

A total of N=469 questionnaires were completed.

It is not acceptable to assign online self-selection non-probability surveys a margin of error. However, a probability sample of this nature would be considered accurate ± 1.6%, 19/20 times.

Role of Festival Hydro

The following descriptive preamble was first presented to customers. They were then asked the first question about how well they understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of their bill relates to Festival Hydro.

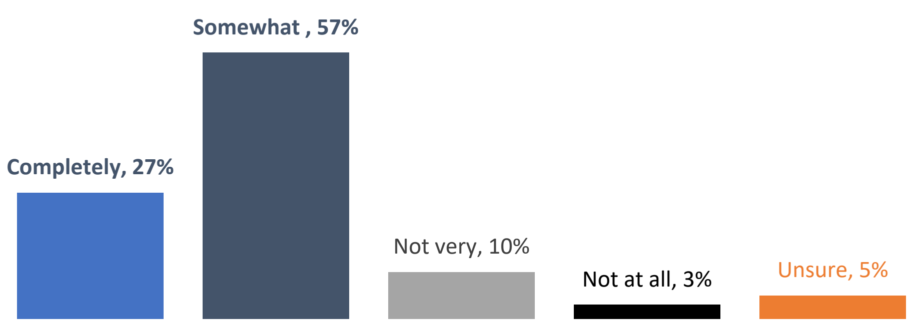
"Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It's made up of three major components: generation, transmission, and distribution. Festival Hydro is a distribution company that carries the electricity from the transformer stations to your homes. Festival Hydro manages its spending in two ways– an operating budget and a capital budget.

• Festival Hydro's operating budget covers recurring expenses, such as the maintenance of distribution system infrastructure, equipment, vehicles, buildings, properties, and tools, as well as insurance and corporate income taxes.

•Festival Hydro's capital budget covers items that have benefits over many years. This includes distribution system equipment such as poles, wires, cables, transformers, computers and information systems, vehicles, and facilities.

Managing the distribution system requires considerable investments in replacing aging equipment, connecting new customers, maintenance, and day-to-day operations. Festival Hydro's portion of the average bill is 26% of the total bill. This portion is used to maintain, enhance, and rebuild the system and includes a regulated rate of return that is used to reinvest in the system."

Q1. How well do you feel you understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of your bill relates to Festival Hydro?



Automated Tools / Communication Methods

The following was first presented to customers after which they were asked which of three options they would most prefer.

"In a previous customer engagement survey from earlier this year, Festival Hydro noted that it is looking to invest in automated tools and communication methods for customer service. Some of these items could include website chat features for customer inquiries, an app that would display usage information, and further online forms. More than half of customers responded that this is important and that they were willing to pay more for customer service tools (less than $1 extra per month). Festival Hydro has built-in minor enhancements to its plans that will allow for more self-service options."

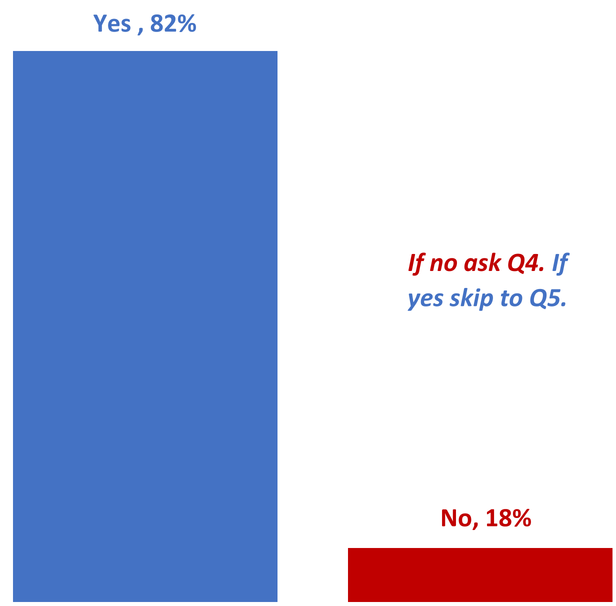
Q2. Which of the following would you prefer:

	Percentage
Increase customer service enhancements (such as an app with usage information) with increased costs.	48%
Continue with planned enhancements but do not need more tools such as an app or website chat features.	34%
Decrease costs by lowering levels of customer service than what is currently provided (this could include longer telephone wait times or email response times).	17%
Unsure	2%

E-Billing

Respondents were then asked if they currently receive an E-bill from Festival Hydro.

Q3. Do you currently receive an E-bill from Festival Hydro?



A total of 82% N=328 of Festival Hydro customers currently receive an E-bill.

The 18% (N=72) of customers that do not receive an E-bill from Festival Hydro were asked Q4 as a follow-up question, while all others skipped to Q5.

Q4. *The cost of receiving a paper bill to customers is approximately $1 per month per customer or $12 per year. What is preventing you from registering to receive an E-bill?*

	Percentage
Receiving the bill by mail is a reminder to pay.	26%
I was not aware that the cost savings of e-billing help offset future cost increases.	17%
It is more convenient to receive the bill by mail.	14%
I am concerned about online security from receiving electronic bills.	12%
Prefer paper copies.	11%
Have not gotten to it yet.	8%
I do not have regular access to the internet.	5%
Not aware that option existed.	6%
I am not comfortable with technology.	2%

In an open-ended probe, all N=400 respondents were asked if they had any recommendations for improvements to the E-billing process.

Q5. Do you have any recommendations on improvements to the E-billing process?

	Percentage
Unsure	35%
No comment	21%
None	17%
Simplify process / streamline	6%
Improve security / secure online payments/data security	4%
Be more detailed / more information	3%
Online customer support / real-time support	2%
Send out payment reminders	2%
Offer payment options	2%
Offer energy-saving tips/energy pricing	1%
Able to view past payment history / past billing	1%
Improve user experience (generally)	1%
Shorter billing cycle	1%
Provide an area for comments/suggestions	1%
Improve mobile capabilities / SMS	1%
Provide services in multi-languages	<1%
Provide billing installments/payments	<1%
Provide info on power outages	<1%
Dislike generally	<1%
Send payment statuses	<1%

Emerging Technologies

Respondents were then asked about their opinions about investing in new technologies and pilot projects.

Q6. Which of the following would you prefer?

	Percentage
Invest more money in renewable energy and environmentally friendly options at an additional cost (e.g., including solar, alternative energies such as Hydrogen, etc. and electric vehicle stations)	35%
Invest more money in new technologies at an additional cost (e.g. including customer tools and automated smart switches, electric fleet vehicles)	29%
Both investing in renewables & amp; new technologies at an additional cost	25%
Continue investing in traditional infrastructure	8%
Unsure	3%

A total of 35% of Festival Hydro customers would prefer if they invested more money in renewable energy and environmentally friendly options at an additional cost, while 29% would like to see them invest more money in new technologies at an additional cost. 25% of respondents would like to see them both investing in renewables and amp; new technologies at an additional cost however 8% would like Festival Hydro to continue investing in traditional infrastructure. A total of 3% were unsure.

Legacy Metering Network

Respondents were then read a preamble explaining the multi-year replacement of its legacy metering network and assets. They were then asked which option they would prefer.

"Included in Festival Hydro's plans for 2025, is a multi-year replacement of its legacy metering network and assets which will provide improved and more reliable information to Festival Hydro and its customers. One of the solutions that Festival Hydro is considering has applications on the meter that the customer could download in the future and gain better insight into electricity use by appliance, as well as potential future uses for electric vehicles and receive information on when the best time to turn on/off major appliances (e.g. Air Conditioner)."

Q7. *Which of the following would you prefer?*

	Percentage
I would be interested in this type of application and would likely use it.	59%
I might be interested but not sure if I would use it.	33%
I would not use this type of application.	7%
Unsure	1%

Tree Trimming

Respondents were then questioned about Festival Hydro's tree trimming policies. They were asked which statement best aligned with their views on tree trimming by Festival Hydro.

"Festival Hydro must trim trees in proximity to overhead lines to avoid trees contacting lines for safety and reliability. Currently, Festival Hydro provides tree trimming on a cyclical basis to assist with limiting outages from tree contact and animal interference. The cost of this vegetation management continues to increase annually."

Q8. *Which of the following statements best aligns with your view on tree trimming by Festival Hydro?*

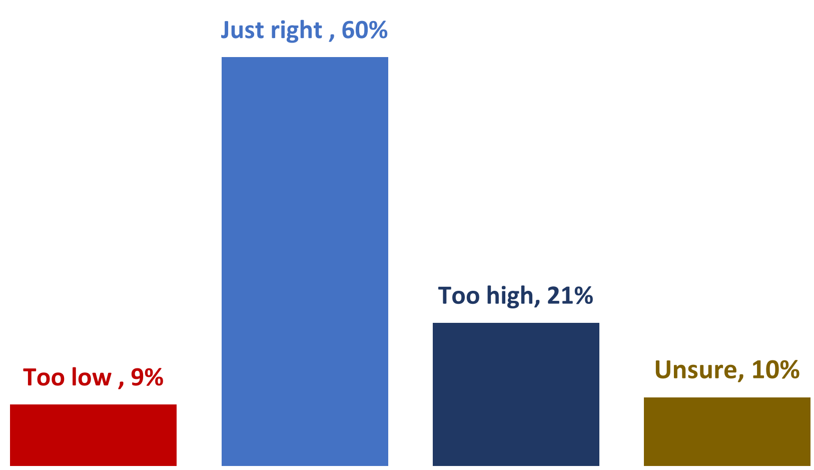
	Percentage
I support the current Festival Hydro process of more frequent tree trimming with appropriate clearance to balance reliability, aesthetic, and environmental concerns.	44%
I would like trees trimmed more frequently where possible with branches cut back more than today, regardless of aesthetic or environmental concerns, so that fewer power outages occur and there are shorter wait times to restore power after storms, and costs are reduced.	40%
I prefer trees trimmed with less clearance and lower frequency than current practice because of aesthetic and environmental reasons and will accept more power outages, longer wait times to restore power after storms, and increases in costs for tree trimming and responding to outages.	14%
Unsure	3%

Future Renewal Expenditures

Respondents were read a preamble about Festival Hydro's future renewal expenditures. They were then asked to indicate if they felt this proposed overall level of future system renewal expenditures was too low, just right, or too high to meet the objectives of safety, reliability, and cost.

"Asset renewal costs from 2015 and on were on average $1.9 million per year. For 2025-2029 Festival Hydro is proposing $3.6 million on average. The increase is due to the need to replace aging infrastructure to maintain the safety and reliability of the distribution system. The new levels of replacement are being done to maintain the current demographics and condition of our assets. This means that Festival Hydro will be replacing more poles, more underground cables, and more transformers each year. In addition, average material costs have increased from 40%-90% since 2019. Asset renewal costs represent about 47% of Festival Hydro's total capital investments."

Q9. In your opinion,is this proposed overall level of future system renewal expenditures too low, just right, or too high to meet the objectives of safety, reliability, and cost?



A total of 60% of respondents felt that the proposed overall level of future system renewal expenditures was just right, 21% too high while 9% indicated too low. A total of 10% were unsure.

Rate Increases

Respondents were then asked to indicate what best represented their point of view regarding the standard annual rate increase.

"Festival Hydro receives a standard increase annually that is less than inflation but is eligible to file a rate application based on current cost levels every five years. The last full-cost application was in 2015. The preliminary monthly rate impact to the average residential customer distribution portion is approximately $6.75 or 5.1% on the total bill holding other things constant (Time of Use (TOU)/Tiered/Ultra Low Overnight (ULO) Rates, Ontario Electricity Rebate). Please note that these are preliminary estimates and are subject to change as the rate application process continues."

Q10. Which of the following best represents your point of view on this rate increase?

	Percentage
I don't like the idea of a rate increase, but it is necessary.	52%
The rate increase is reasonable.	30%
The rate increase is unreasonable.	14%
Unsure	4%

2023 Telephone Survey Report

December 2023

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Background & Overview

Festival Hydro commissioned Brickworks Communications to survey its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by Festival Hydro.

Brickworks and Festival Hydro designed the questionnaire. This report contains an executive overview of the findings, while a separate report in Excel includes the results of each question.

Methodology & Logistics

Study Sample

Festival Hydro provided a customer database to be used as a sample frame.

Survey Method

All surveys were completed online using Computer Assisted Telephone Interviewing (CATI).

Logistics

A total of N=400 questionnaires were completed between the days of November 22nd and December 11th, 2023.

Confidence

The margin of error for this survey is ± 4.9%, 19/20 times.

Role of Festival Hydro

The following descriptive preamble was first presented to customers. They were then asked the first question about how well they understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of their bill relates to Festival Hydro.

"Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It's made up of three major components: generation, transmission, and distribution. Festival Hydro is a distribution company that carries the electricity from the transformer stations to your homes. Festival Hydro manages its spending in two ways– an operating budget and a capital budget.

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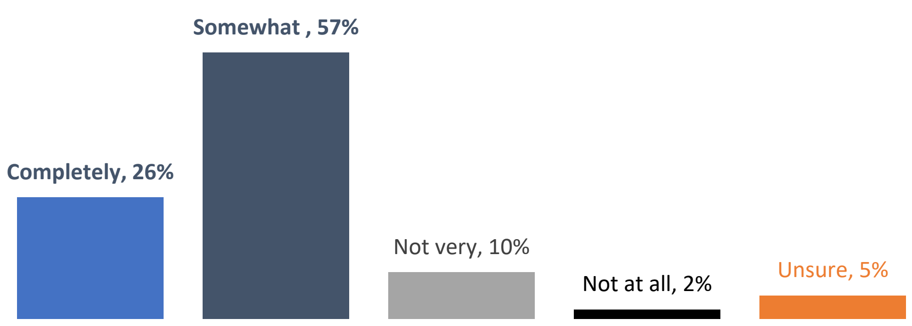
Managing the distribution system requires considerable investments in replacing aging equipment, connecting new customers, maintenance, and day-to-day operations. Festival Hydro's portion of the average bill is 26% of the total bill. This portion is used to maintain, enhance, and rebuild the system and includes a regulated rate of return that is used to reinvest in the system."

Q1. How well do you feel you understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of your bill relates to Festival Hydro?



A total of 57% of respondents said they somewhat understand the role that Festival Hydro plays in the electricity system, and 26% claimed to completely understand. Only 10% do not understand it very well and 2% do not at all. A total of 5% of respondents were unsure.

Automated Tools / Communication Methods

The following was fist read to customers after which they were asked which of four options they would most prefer.

"In a previous customer engagement survey from earlier this year, Festival Hydro noted that it is looking to invest in automated tools and communication methods for customer service. Some of these items could include website chat features for customer inquiries, an app that would display usage information, and further online forms. More than half of customers responded that this is important and that they were willing to pay more for customer service tools (less than $1 extra per month). Festival Hydro has built-in minor enhancements to its plans that will allow for more self-service options."

Q2. Which of the following would you prefer:

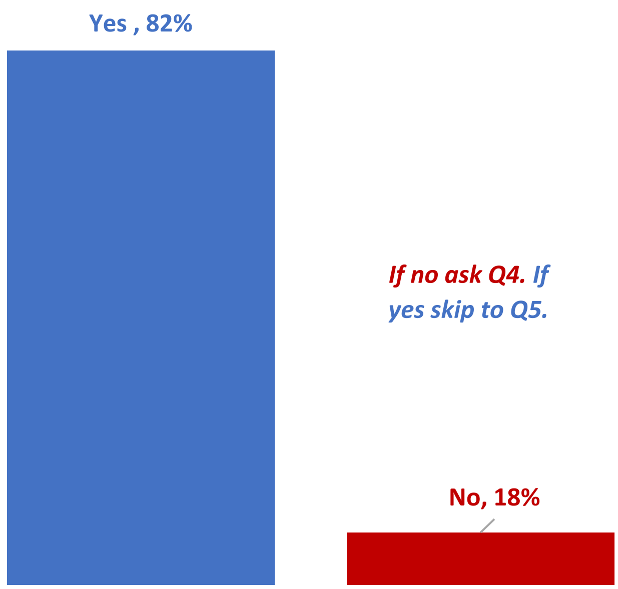
	Percentage
Increase customer service enhancements (such as an app with usage information) with increased costs.	49%
Continue with planned enhancements but do not need more tools such as an app or website chat features.	36%
Decrease costs by lowering levels of customer service than what is currently provided (this could include longer telephone wait times or email response times).	13%
Unsure	2%

Most named by almost half or 49% is having an increase in customer service enhancements, such as a usage app, even if it means increased costs. The next most referenced by 36% was to continue with planned enhancements but not with new tools or features. Only 13% wanted decreased costs by lowering customer service, while 2% were unsure.

E-Billing

Respondents were then asked if they currently receive an E-bill from Festival Hydro.

Q3. Do you currently receive an E-bill from Festival Hydro?



A total of 82% or N=328 of Festival Hydro customers currently receive an E-bill.

The 18% (N=72) of customers that do not receive an E-bill from Festival Hydro were asked Q4 as a follow-up question, while all others skipped to Q5. Customers were prompted with a list of possible responses

Q4. The cost of receiving a paper bill to customers is approximately $1 per month per customer or $12 per year. What is preventing you from registering to receive an E-bill?

	Percentage
Receiving the bill by mail is a reminder to pay.	25%
I was not aware that the cost savings of e-billing helps offset future cost increases.	17%
It is more convenient to receive the bill by mail.	15%
I am concerned about online security from receiving electronic bill.	10%
Prefer paper copy.	10%
Have not gotten to it yet.	8%
I do not have regular access to the internet.	7%
Not aware that option existed.	6%
I am not comfortable with technology.	3%

In an open-ended probe, all N=400 respondents were asked if they had any recommendations for improvements to the E-billing process.

Q5. Do you have any recommendations on improvements to the E-billing process?

	Percentage
Unsure	35%
No comment	20%
None	15%
Simplify process / streamline	9%
Be more detailed / more information	8%
Improve security / secure online payments / data security	5%
Online customer support / real-time support	2%
Send out payment reminders	2%
Able to view payment history / past billing	1%
Offer payment options	1%
Offer energy-saving tips / energy pricing	1%
Provide billing installments/payments	1%
Provide service in multi-languages	<1%
Improve user experience (general)	<1%
Send receive payment notices	<1%

Emerging Technologies

Respondents were then asked their opinions about investing in new technologies and pilot projects. They were presented with a list of options and were asked to select their top choice.

Q6. Which of the following would you prefer?

	Percentage
Invest more money in renewable energy and environmentally friendly options at an additional cost (e.g., including solar, alternative energies such as Hydrogen, etc. and electric vehicle stations)	37%
Invest more money in new technologies at an additional cost (e.g. including customer tools and automated smart switches, electric fleet vehicles)	30%
Both investing in renewables and new technologies at an additional cost	25%
Continue investing in traditional infrastructure	6%
Unsure	3%

Investing in renewable energy was most referenced, followed by investing in new technologies and then investing in both renewables and new technologies.

Legacy Metering Network

Respondents were then read a preamble explaining the multi-year replacement of its legacy metering network and assets. They were then asked which of the three options they would prefer.

"Included in Festival Hydro's plans for 2025, is a multi-year replacement of its legacy metering network and assets which will provide improved and more reliable information to Festival Hydro and its customers. One of the solutions that Festival Hydro is considering has applications on the meter that the customer could download in the future and gain better insight into electricity use by appliance, as well as potential future uses for electric vehicles and receive information on when the best time to turn on/off major appliances (e.g. Air Conditioner)."

Q7. *Which of the following would you prefer?*

	Percentage
I would be interested in this type of application and would likely use it.	60%
I might be interested but not sure if I would use it.	33%
I would not use this type of application.	6%
Unsure	1%

Most, or six in ten respondents would be interested in this type of application and would be likely to use it, 33% might be interested.

Tree Trimming

Respondents were then questioned about Festival Hydro's tree trimming policies. They read three statements and were asked which one best aligned with their views on tree trimming.

"Festival Hydro must trim trees in proximity to overhead lines to avoid trees contacting lines for safety and reliability. Currently, Festival Hydro provides tree trimming on a cyclical basis to assist with limiting outages from tree contact and animal interference. The cost of this vegetation management continues to increase annually."

Q8. Which of the following statements best aligns with your view on tree trimming by Festival Hydro?

	Percentage
I support the current Festival Hydro process of more frequent tree trimming with appropriate clearance to balance reliability, aesthetics, and environmental concerns.	44%
I would like trees trimmed more frequently where possible with branches cut back more than today, regardless of aesthetic or environmental concerns, so that fewer power outages occur and there are shorter wait times to restore power after storms, and costs are reduced.	42%
I prefer trees trimmed with less clearance and lower frequency than current practice because of aesthetic and environmental reasons and will accept more power outages, longer wait times to restore power after storms, and increases in costs for tree trimming and responding to outages.	12%
Unsure	2%

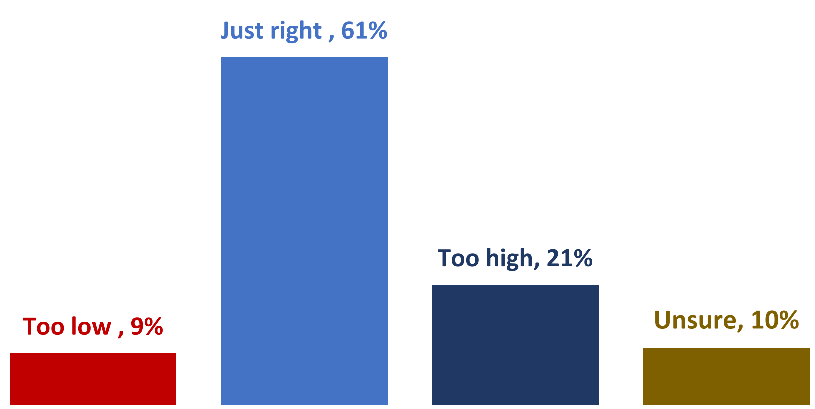
There was a near-even split between those who support the current process and those who would like more frequent trimming.

Future Renewal Expenditures

Respondents were read a statement about Festival Hydro’s future renewal expenditures. They were then asked to indicate if this overall level of future system renewal expenditures was too low, just right, or too high to meet the objectives of safety, reliability, and cost.

“Asset renewal costs from 2015 and on were on average $1.9 million per year. For 2025-2029 Festival Hydro is proposing $3.6 million on average. The increase is due to the need to replace aging infrastructure to maintain the safety and reliability of the distribution system. The new levels of replacement are being done to maintain the current demographics and condition of our assets. This means that Festival Hydro will be replacing more poles, more underground cables, and more transformers each year. In addition, average material costs have increased from 40%-90% since 2019. Asset renewal costs represent about 47% of Festival Hydro’s total capital investments.”

Q9. In your opinion,is this proposed overall level of future system renewal expenditures too low, just right, or too high to meet the objectives of safety, reliability, and cost?



A total of 61% of respondents felt that the proposed overall level of future system renewal expenditures was just right, 21% said it was too high, and 9% indicated too low. A total of 10% were unsure.

Rate Increases

Respondents were then asked to indicate what best represented their point of view regarding the standard annual rate increase.

"Festival Hydro receives a standard increase annually that is less than inflation but is eligible to file a rate application based on current cost levels every five years. The last full-cost application was in 2015. The preliminary monthly rate impact to the average residential customer distribution portion is approximately $6.75 or 5.1% on the total bill holding other things constant (Time of Use (TOU)/Tiered/Ultra Low Overnight (ULO) Rates, Ontario Electricity Rebate). Please note that these are preliminary estimates and are subject to change as the rate application process continues.'"

Q10. Which of the following best represents your point of view on this rate increase?

	Percentage
I don't like the idea of a rate increase, but it is necessary.	51%
The rate increase is reasonable.	32%
The rate increase is unreasonable.	13%
Unsure	4%

Slightly more than half of respondents or 51% do not like the idea of a rate increase but feel it is necessary. Nearly a third or 32% feel the rate increase is reasonable, while 13% said it is unreasonable. A total of 4% were unsure.

Attachment 1 –11

FHI Business Plan

BUSINESS PLAN

Festival Hydro INC.

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1. OVERVIEW

1.1 EXECUTIVE SUMMARY

Festival Hydro Inc. (FHI) was incorporated in 2000 and is a wholly owned subsidiary of the City of Stratford. The principal activity of FHI is to distribute electricity to the residents and businesses in the City of Stratford and the towns of Brussels, Dashwood, Hensall, Seaforth, St. Marys, and Zurich, under a license issued by the Ontario Energy Board ("OEB").

FHI has developed this business plan to be incorporated into FHI's Cost of Service (COS) Application. This plan outlines FHI's guiding principles and strategic goals and initiatives, its 2025 capital and operating budget, as well as areas of alignment with the Renewed Regulatory Framework (RRF). The plan also includes other important highlights to describe the unique challenges and opportunities that FHI faces and the performance metrics that are used to measure success.

2. GUIDING PRINCIPLES & STRATEGIC GOALS

2.1 MISSION, VISION, VALUES, PURPOSE STATEMENTS

Mission – To responsibly provide value to our customers, communities, shareholders, and employees through cost effective distribution of reliable and safe electric power.

Vision – We enable prosperity within our communities through exceptional people, partnerships, and performance.

Values –

- People first through positive teamwork
- Accountability
- Honesty
- Commitment to customers
- Trust

Purpose – Powering lives, empowering communities.

2.2 STRATEGIC GOALS & INITIATIVES

1. **Our People** - Recognizing our team of staff is the most critical component of our business success. It is imperative that the organization ensures the success of our employees and recognizes that the safety of our people is paramount, to sustain the organization, skillfully adapt to change, and implement efficiencies that will lead to the optimization of resources and capacity, enhanced service delivery, and increased value for all stakeholders.

Goals:

- To ensure the safety of our staff is paramount.
- To create a sustainable, motivated workforce and enhance productivity.
- To be viewed as a great place to work.

2. Invest in New Operational Technology - Technology is constantly changing and developing at a rapid pace. Every day, new technologies are launched that can improve upon efficiencies and processes that the business relies on. By working with our internal teams to better understand their day-to-day processes, we can formulate a plan and look for technologies that fit the unique needs of our teams, help to reduce reliance on paper, and improve upon customer and employee experiences.

   Goals:

   - To mitigate costs where possible and improve operational efficiencies.
   - To improve internal and external communications.
   - To enhance and improve the customer experience.

3. Collaborate with Other Local Community Stakeholders - As a locally owned utility we have a unique opportunity to work in partnership with the municipality and economic development team to attract new business, investment, and opportunities to the community. We understand the value of having strong relationships with community members and customers. Through enhanced collaboration and relationship building, we can seek to better understand the goals and needs of our customers and communities to ensure that their needs are met and that we are acting as a partner in their success.

   Goals:

   - Enhance long term viability.

4. Create Scale in the Utility Space - Just as we recognize the incredible value of relationship building with stakeholders in the communities we serve, we also emphasize the importance of teamwork and collaboration with our peers in the energy industry. By seeking out shared service opportunities, participating in working groups and industry councils, and forging strategic partnerships with other utilities, we have the opportunity to learn from others, leverage the power that comes from unity, better control costs, and contribute to setting the standards for industry best practices. This will help to ensure continued. Responsible. and value-driven operation of our organization well into the future.

   Goals:

   - To mitigate costs where possible and enhance efficiency.
   - Ensure financial viability.
   - Business continuity.

3. UTILITY OVERVIEW

3.1 UTILITY DESCRIPTION & OWNERSHIP

FHI is wholly owned by the City of Stratford. FHI is the licensed distributor of electricity. Festival Hydro Services Inc. (FHSI) is also wholly owned by the City of Stratford. FHI and FHSI have the same President and this individual is the main contact with the parent company officials. There are also City of Stratford Council members on the FHI and FHSI Board of Directors, and as such, represent reporting relationships between utility management and parent company officials.

FHI is comprised of seven geographically separate service territories (City of Stratford, Towns of St. Marys, Seaforth, Dashwood, Hensall, Zurich, Brussels) and each service territory is bounded by Hydro One Networks Inc. FHI serves approximately 23,000 customers within these communities.

3.2 CORPORATE STRUCTURE

The municipal Shareholder appoints directors to the Board of Directors of FHI. The Board consists of eight (8) Directors, three (3) of which are municipal representatives, and the remainder are independent. The President and Chief Executive Officer (CEO) is a non-voting member of the Board and holds the Secretary position. The Executive Team consists of the President and CEO, Chief Financial Officer (CFO), Vice President of Engineering and Operations, and the Vice President of Information Technology.

There are no planned changes in corporate or operational structure, as well as no changes to its legal organization and control.

3.3 ECONOMIC OVERVIEW OF THE SERVICE AREA

The City of Stratford and surrounding areas have an economically diverse base including manufacturing, tourism, commercial, financial, agricultural, and service industries which has allowed for a reasonably stable and prosperous business environment in Southwestern Ontario.

In a recent article (https://www.stratfordbeaconherald.com/news/local-news/good-news-and-bad-news-in-think-tanks-report-on-stratfords-economy), it was noted "Stratford's investments into economic development during the two years leading up to the COVID-19 pandemic have paid off, but job vacancy rates above provincial and national levels continue to signal an emerging shortage of skilled labour, a new report says." It also noted "Along with its aging population – the age distribution of Stratford's residents has become increasingly skewed towards older groups – the city's tight labour market "is another signal of a potential issue with a shortage of skilled labour," the report said. Lastly, the article noted that the "Stratford area's population grew by an annual average of 0.8 per cent within that 10-year stretch" referring to 2011-2021. The residential base of FHI customers has a large impact on usage trends, ability to pay, and needs and preferences; making it important for FHI to monitor customer distribution to ensure services cater to this base and risks are mitigated where possible.

3.4 KEY CHALLENGES AND MITIGATIONS

There are several challenges that Festival Hydro has been and will continue to be facing in the upcoming years. Many of these challenges are external environmental challenges and are being faced by other LDCs or organizations in Canada. Beyond the external challenges, FHI last filed a Cost of Service Application in 2015. At that time, the Application did not include requests for investments that would assist in moving FHI forward beyond traditional renewal expenditures at historical spending limits. Due to this there were several systems, tools and building needs that were not invested in. The system applications do not meet the needs of FHI, and some are obsolete and are no longer being supported. The building required significant upgrades to allow for an appropriate employee work environment. This Application considers the current system needs, as well as will better prepare FHI for the future and considers several of the challenges that are noted below. Without the recent and proposed investments, FHI would not be able to fulfill its mission, vision, and values.

Economy and Rising Costs

Recent inflation has increased to the highest point that Canada has experienced in 40 years. This was driven by large increases in costs across the board including energy, gasoline, housing, labour and basic goods and services. While inflation has been rising, so have interest rates, which has caused significant additional interest costs on debt. This environment has caused virtually all costs within the utility to increase, and they are increasing by substantial amounts. Key materials have cost FHI between 40 and 100% more between 2019 and 2023. Insurance, professional services, and benefits costs have also been increasing by double digits annually.

FHI attempts to mitigate this risk by continually finding process improvements to offset cost increases. It also uses its purchasing policy to ensure a competitive purchasing process with mid- to longer-term contracts to lock in prices where possible.

Supply Chain

Supply chain challenges began with Covid-related backlogs but were further strained by global unrest. This has made supplies hard to obtain and more expensive, with limited information on lead times. As noted above, FHI has seen large increases in the cost of materials and must plan well in advance to ensure that construction can proceed with the materials and equipment that are required.

To assist in mitigating this risk, FHI has re-negotiated many contracts with suppliers to assist with supply certainty, regarding both cost and delivery; however, this is not guaranteed. FHI also ensures that it maintains strong vendor relationships which can assist with pricing and lead times.

Labour Market

Over the past several years there has been a strain on talent within the labour market with competition and inflation pushing wages and benefits upwards. An article by Forbes (https://www.forbes.com/sites/forbesbusinesscouncil/ 2023/06/28/ the-war-for-talent-is-on/?sh=5b5f22216657) notes, “With estimates that the global talent shortage could reach 85 million people by 2030, it’s clear that a market-wide talent shortage is on for the long term and business leaders need to take it seriously.”

FHI attempts to mitigate this risk by making ‘Our People’ it’s top initiative. Engaged and satisfied employees lead to the overall success of the organization including increased productivity, innovative ideas, and strong customer service. FHI recently received strong results on its biennial Employee Satisfaction Survey. The highest overall categories were health and safety (training, rules/regulations, JHSE), employees’ awareness of company goals and objectives, teamwork, trust, and cooperation. The lowest ranking areas included: fair and affordable compensation, and rewards and recognition. FHI attempts to ensure that compensation is competitive to surrounding utilities and other local comparators.

Innovation

An article by the Climate Institute (https://climateinstitute.ca/wpcontent/uploads/2021/09/CICC-Barriers-to-innovation-in-the-Canadian-electricity-sector-and-available-policy-responses-by-Sara-Hastings-Simon-FINAL-1.pdf) states, “In most cases in Canada, the system operator or utility lacks the clear mandate and necessary incentives to pursue decarbonization or long-term climate resilience of the electricity system. This, in turn, limits the ability and incentive to deploy new or innovative technology. Instead, there is a laser focus on providing reliable electricity at the lowest cost. While this mandate remains critical, it becomes a challenge when it is the only goal. Providing the ability to consider innovation is important, but even the ability without a clear direction and incentive is insufficient to drive action at the pace and scale required. Rather, a clear mandate is necessary given the understandably conservative nature, culture, and mindset of utility system operators.” It goes on further to state, “As a result of this mandate and mindset, there is little appetite for individuals within the utility system to make changes to integrate new technology. This leads to preferences for the same types of resources that have been historically used and are well understood, meaning large fossil, hydro, or nuclear generation.” Under the current regulatory framework, there is a focus on lowering costs, but limited incentive to search, study and try new innovative solutions.

FHI is monitoring this risk and considering potential innovative solutions that could work for its customers and within its service territory.

Aging Critical Systems and Infrastructure

FHI has several critical systems that have been, or are in the process of being, replaced such as the Customer Information System (CIS), Enterprise Resource Planning System (ERP) and

Advanced Metering Infrastructure 2.0 (AMI 2.0) which are all nearing or beyond end of life. The CIS and ERP were both with a vendor who will no longer support the products due to FHI being one of the only Canadian customers using these systems. This created significant risks within the organization such as a risk that new regulations may not be implemented or system failure with lack of support or upgrades. The AMI also needed to be upgraded due to the increasing failure rates being seen, based on the age of the system and manufacturing issues that FHI has experienced, as well as the meters being end of life. In addition to the major system upgrades, FHI's building required significant upgrades to remain functional; completed between 2022 and 2024. Distribution system infrastructure is being replaced in accordance with FHI's Asset Management Process, which uses inputs such as the Asset Condition Assessment (ACA) and paces the replacement of assets in a manner intended to limit impacts to distribution system reliability.

FHI has mitigated these risks by completing both short and long-term capital plans that are paced in a sustainable manner re-informed by the outputs of the ACA. The proposed plan will set FHI up for success over the long-term.

Electrification and Energy Transition

As Ontario plans for Electrification and the Energy Transition as outlined in the December 2023 Report of the Electrification and Energy Transition Panel, "Ontario's Clean Energy Opportunity", LDCs will be tasked with ensuring that it can meet new or increased demand from electrification of transportation, commercial and building infrastructure. This is a challenge for FHI as it attempts to manage demand and future usage projections, while not overbuilding and increasing costs too rapidly. FHI needs to plan and build for the future, but the electrification uptake timeline is unreliable and unknown.

FHI is mitigating this risk by actively monitoring local uptake of electric vehicles (EVs) in the community, discussing future plans with large customers, and monitoring system capacity. FHI consults with the municipality, developers, and customers, as well as looking at historical trends, planning reports from regional planning and IESO's planning outlook. These inputs assist in the understanding of the impacts that EVs or the electrification of other historically alternatively sourced fuels may have on the distribution system in the future and allows FHI to prepare and incorporate those impacts into their investment plans. Proactive steps have been discussed in the DSP.

Cyber Security

An article by Forbes (https://www.forbes.com/sites/bernardmarr/2022/11/15/the-7-biggest-business-challenges-every-company-is-facing-in-2023/?sh=226b2fe15688) notes, "Cyberattacks are on the rise, and ransomware and phishing scams are now a common occurrence. As businesses become more digital, they accumulate more data, which becomes highly attractive to cybercriminals that intend to steal it and hold organizations hostage to monetary demands." Utilities are a vulnerable target because of the critical service that is provided as well as access to large volumes of data.

FHI is attempting to mitigate this risk by actively following the OEB's Cyber Security Framework (CSF), investing in cyber security initiatives, and educating staff and board members on vulnerabilities.

Information Technology Changes

Over the past several years there has been a shift from on premise IT solutions to cloud computing or System as a Service (SAAS) models. There are many practical benefits to cloud-based solutions such as security, disaster recovery, accessibility, and performance. In addition, there are several service providers who no longer offer on-premise solutions. This limits the vendor and product options available if on-premise solutions are preferred. The current funding structure disincentivizes LDCs from moving to cloud-based solutions.

Changes to Regulation

Since the last time FHI filed a Cost of Service, there have been several regulation changes which required significant system upgrades including both time and cost to implement. Some of these changes include, but are not limited to, Customer Optionality including tiered and Ultra-Low Overnight (ULO) price plans, Green Button, Activity and Program-based Benchmarking (APB), Net Metering price plans, 1588 & 1589 Accounting Guidelines, Market Participant Readiness (MRP), Ontario Energy Rebate (OER), changes to Customer Service Rules, Cyber Security Framework, and the Ontario Electricity Support Program (OESP). As these new regulations arise, FHI is forced to pivot from ongoing operations and focus time and funds to the new regulations.

4. BUDGET OVERVEIW

4.1 KEY BUDGET CONSIDERATIONS

The 2025 budget was prepared in mid to late 2023 with adjustments made after customer engagement and was complete prior to the Board of Directors approval in Q1 of 2024. The following considerations were made when preparing the 2025 budget:

- Capital plans for renewal work should incorporate the outcomes and recommendations of the ACA.
- Large capital investments related to ERP and AMI should be based on the best estimates presented in RFP submissions.
- Where unknown, Operating, Maintenance and Administration costs are estimated to increase at 4%.
- Labour increases are estimated to increase at 3.5%. FHI's union contract expires April 30, 2025, so it is unknown at the time of the budget and Application what the result of the negotiation will be.
- Continued investment and improvements to customer facing services to best serve customers.

4.2 SUMMARY OF FHI'S 2025 BUDGETS

Capital Investments

The following table summarizes FHI's historical actual capital investments, as well as forecasted investments for the 2024 Bridge Year, and the 2025-2029 period covered by its Distribution System Plan (DSP). The DSP which includes variance and project details are included in Exhibit 2 of the Application.

Category	2015	2016	2017	2018	2019
			$'000		
System Access (Gross)	713	583	733	1,378	1,200
System Renewal (Gross)	1,706	1,427	1,644	1,565	1,768
System Service (Gross)	238	38	29	38	30
General Plant (Gross)	653	555	549	837	613
Gross Capital Expenses	**3,309**	**2,603**	**2,956**	**3,818**	**3,611**
Contributed Capital	(334)	(207)	(372)	(585)	(444)
Net Capital Expenses after Contributions	**2,975**	**2,396**	**2,584**	**3,233**	**3,168**
	2020	**2021**	**2022**	**2023**	**2024**
			$'000		
System Access (Gross)	1,086	1,091	1,013	1,186	1,212
System Renewal (Gross)	1,627	2,027	2,222	2,114	2,236
System Service (Gross)	51	6	34	110	77
General Plant (Gross)	460	876	907	1,927	4,193
Gross Capital Expenses	**3,225**	**4,000**	**4,175**	**5,337**	**7,717**
Contributed Capital	(466)	(481)	(343)	(447)	(219)
Net Capital Expenses after Contributions	**2,759**	**3,519**	**3,832**	**4,891**	**7,498**
	2025	**2026**	**2027**	**2028**	**2029**
			$'000		
System Access (Gross)	2,399	2,463	2,531	2,601	1,743
System Renewal (Gross)	3,101	3,351	3,421	3,505	3,590
System Service (Gross)	359	374	384	397	409
General Plant (Gross)	1,878	1,299	1,262	1,274	1,585
Gross Capital Expenses	**7,737**	**7,487**	**7,598**	**7,777**	**7,327**
Contributed Capital	(327)	(332)	(338)	(345)	(352)
Net Capital Expenses after Contributions	**7,410**	**7,155**	**7,260**	**7,432**	**6,975**

Operating, Maintenance and Administration (OM&A)

The following table summarizes FHI's 2015 Board Approved Expenses compared to the proposed 2025 Expenses. Cost drivers are discussed in detail in Exhibit 4 of the Application.

Expenses	2015 Board Approved	2025 Test
Distribution Expenses - Operation	924,800	1,368,552
Distribution Expenses - Maintenance	1,217,983	2,146,761
Billing and Collecting	1,212,817	1,707,271
Community Relations	11,248	19,427
Administration and General Expenses	1,789,432	4,013,523
Property Tax	19,225	154,677
LEAP	13,000	20,050
Total Recoverable OM&A Expenses	**5,188,505**	**9,430,261**
PILs	142,100	220,759
Depreciation	2,082,559	2,969,170
Total	**7,413,164**	**12,620,190**

Revenue Deficiency

The following table summarizes FHI's revenue deficiency which is requested to be recovered as part of this Application.

Description	2025 Test Year at Existing Rates	2025 Test Year - Required
Revenue		
Revenue Deficiency		**2,813,456**
Distribution Revenue	13,397,254	13,397,254
Other Operating Revenue (Net)	1,166,332	1,166,332
Total Revenue	**14,563,586**	**17,377,042**
Costs and Expenses		
Administrative & General, Billing & Collecting	5,740,221	5,740,221
Operation & Maintenance	3,515,313	3,515,313
Donations - LEAP	20,050	20,050
Depreciation & Amortization	2,969,170	2,969,170
Property Taxes	154,677	154,677
Deemed Interest	2,097,975	2,097,975
Total Costs and Expenses	**14,497,406**	**14,497,406**
Utility Income Before Income Taxes	**66,180**	**2,879,636**
Income Taxes:		
Corporate Income Taxes	(524,807)	220,759
Total Income Taxes	**(524,807)**	**(220,759)**
Utility Net Income	**590,987**	**2,658,876**
Actual Return on Rate Base:		
Rate Base	72,173,625	72,173,625
Interest Expense	2,097,975	2,097,975
Net Income	590,987	2,658,876
Total Actual Return on Rate Base	**2,688,962**	**4,756,852**
Actual Return on Rate Base	3.73%	6.59%
Required Return on Rate Base:		
Rate Base	72,173,625	72,173,625
Return Rates:		
Return on Debt (Weighted)	4.84%	4.84%
Return on Equity	9.21%	9.21%
Deemed Interest Expense	2,097,975	2,097,975
Return On Equity	2,658,876	2,658,876
Total Return	**4,756,852**	**4,756,852**
Expected Return on Rate Base	6.59%	6.59%
Revenue Deficiency After Tax	**2,067,890**	**0**
Revenue Deficiency Before Tax	**2,813,456**	**0**

5. OUTCOMES OF THE RENEWED REGULATORY FRAMEWORK

On October 18, 2012, the OEB issued its "Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach." The report set out a comprehensive framework economic regulation of the Ontario distribution sector (the Renewed Regulatory Framework, or "RRF"), which emphasizes the importance of performance outcomes in four key categories:

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

The sections below describe how FHI continues to engage with its customers in order to better understand their needs, expectations, and preferences, and how FHI's core values, customer preferences, and the RRF performance are integrated and prioritized in its plan.

5.1 CUSTOMER FOCUS

5.1.1 CUSTOMER ENGAGEMENT

FHI has always prioritized customer experience and feedback. FHI gathers feedback in many ways including everyday communications with customers through customer service and field services, one on one communications with large customers, community and shareholder outreach, formal biennial customer engagement surveys, as well as Cost of Service-specific surveys completed in 2023.

5.1.2 IDENTIFICATION OF NEEDS & PREFERENCES OF CUSTOMERS

As part of the Cost of Service Application, FHI prepared an online survey to gather high level needs and preferences prior to budget and forecast planning. The results of this survey can be found in Attachment 1-10 of Exhibit 1. After completion of the 2025 budget and forecast, FHI went out to customers with a second survey that was done both online and by telephone to further refine more specific customer facing questions related to the Application. Results from this engagement can be found in Attachment 1-10 of Exhibit 1. Based on these results, the following changes were incorporated into the plan.

Adjustments and Deferrals based on Customer Engagement

Capital Project Description	2025	2026	2027	2028	2029	Total
Underground Cable Replacement	(281,000)	(244,000)	(277,000)	(282,000)	(289,000)	**(1,373,000)**
Animal Mitigation	(10,000)	(10,000)	(13,000)	(15,000)	(18,000)	**(66,000)**
Fleet	-	(155,000)	-	72,000	(152,000)	**(235,000)**
Buildings & Equipment	-	(180,000)	-	(236,000)	(75,000)	**(491,000)**
System Re-establishment	-	(39,000)	(20,000)	(21,000)	(21,000)	**(101,000)**
AMI 2.0	114,000	292,000	299,000	307,000	(614,000)	**398,000**
Total	**(177,000)**	**(336,000)**	**(11,000)**	**(175,000)**	**(1,169,000)**	**(1,868,000)**
Expense Description	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
Tree Trimming	25,000	25,000	25,000	25,000	25,000	**125,000**

5.1.3 ALIGNMENT OF GOALS

In most cases, customer feedback is aligned with the plan and management expectations and goals. In the needs and preferences survey, customers noted the following priorities from most to least important:

1) FHI provides electricity that is ‘reliable’ and ‘safe’ (fewer outages and focuses on public and employee safety).
2) FHI prioritizes aesthetics over most cost-effective solutions when constructing or replacing assets at an increased cost to customers (things such as moving overhead wires underground and moving rear lot infrastructure to front of property).
3) FHI provides electricity at low cost at the expense of reliability, green initiatives, innovation, and customer service.
4) FHI invests in innovative solutions such as smart grid, battery storage, electric vehicle infrastructure, solar and smart home technologies at an increased cost to customers.
5) FHI provides excellent customer service.

In follow up questions, it was clear that the majority of customers are willing to pay more to ensure lower frequency and duration of outages followed closely by spending more to reduce outages using smart grid technology and renewing assets on a timely basis to assist in reliability.

These goals align with the plan asset replacement program, using inputs such as the ACA to indicate which assets are statistically most likely to fail, which assists with reliability. Also included in the plan is paced investment in smart grid technologies which should decrease the duration and number of customers affected by outages.

In the second survey conducted, it was clear that customers are interested in further investment in emerging technologies at an additional cost is important as well as increased tree trimming to reduce outages. This aligns with FHI’s plan as noted there are paced investments in smart grid infrastructure as well as continued monitoring of further innovative solutions. FHI included a $25,000 increase to the tree trimming budget to align with customer feedback. The estimated rate increase was presented at the end of the survey. In response, 83% of telephone respondents and 82% of online respondents answered with either 'I don't like the idea of a rate increase, but it is necessary' or 'the rate increase is reasonable', which is very supportive of the plan presented. While only 13% of telephone customers and 14% of online customers noted that the rate increase was unreasonable, FHI still understands that cost is important to this base of customers, so capital costs totaling $1,868,000 over the forecast period were deferred as noted in the table above.

5.2 SCORECARD METRICS – CUSTOMER FOCUS

5.2.1 SERVICE QUALITY

The following are the scorecard results for Service Quality indicators:

Indicator	2018	2019	2020	2021	2022
New Residential/Small Business Services Connected on Time	99.25%	96.99%	95.31%	97.89%	95.92%
Scheduled Appointments Met on Time	98.93%	98.50%	97.69%	98.88%	97.70%
Telephone Calls Answered on Time	87.59%	88.45%	98.86%	91.71%	90.42%

All of these results reflect FHI's commitment to quality and timely customer service. FHI balances service response times with the cost of staffing. Based on the plan submitted in the COS, these results are expected to continue with a potential dip in telephone calls answered on time during the transition to the new CIS.

5.2.2 CUSTOMER SATISFACTION

The following are the scorecard results for Customer Satisfaction indicators:

Indicator	2018	2019	2020	2021	2022
First Contact Resolution	99.99%	99.99%	99.93%	100%	99.99%
Billing Accuracy	99.95%	99.99%	99.96%	99.98%	99.97%
Customer Satisfaction Survey Results	97%	97%	91%	91%	93%

FHI prioritizes training, accountability, and autonomy of staff, which allows for a high level of first contact resolution as well as billing accuracy. Billing accuracy is a critical component of trust with FHI's customers. Lastly, FHI has continued to receive high customer satisfaction results, but uses feedback from the survey responses to drive decisions. regarding initiatives that could be pursued to improve customer satisfaction. These results are expected to continue based on the plan submitted.

5.3 SCORECARD METRICS- OPERATIONAL EFFECTIVENESS

With respect to the RRF outcome of operational effectiveness, distributors are expected to achieve continuous improvement in productivity and cost performance, while delivering on reliability and quality objectives.

5.3.1 SAFETY

The following are the scorecard results for Safety indicators:

Indicator	2018	2019	2020	2021	2022
Level of Public Awareness	81.00%	81.00%	80.00%	77.00%	77.00%
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C
SEII - Number of General Public Incidents	0	1	0	0	0
SEII - Rate per 10, 100, 1000 km of line	0.000	0.383	0.000	0.000	0.000

FHI's commitment to the safety of the public and our employees remains its number one priority. FHI ensures that safety education and communication are a part of the culture of the organization, and addresses any issues identified in a timely manner. FHI continues to find effective ways to communicate these same safety values and education to its customers and communities.

5.3.2 SYSTEM RELIABILITY AND ASSET MANAGEMENT

The following are the scorecard results for System Reliability and Asset Management indicators:

Indicator	2018	2019	2020	2021	2022
Average Number of Hours that Power to a Customer is Interrupted (SAIDI)	0.92	1.79	1.27	1.95	0.81
Average Number of Times that Power to a Customer is Interrupted (SAIFI)	0.73	1.78	1	1.63	0.77
Asset Management - Distribution System Plan Implementation Progress	104%	112%	92%	105%	95%

FHI's historical investments have provided safe and reliable power to its customers, which is evident in the reliability indices. FHI's planned investments aim to continue this trend by targeting the replacement of assets most likely to impact reliability.

Cost Control

The following are the scorecard results for Cost Control indicators:

Indicator	2018	2019	2020	2021	2022
Efficiency Assessment	4	3	3	3	3
Total Cost per Customer	$658	$650	$629	$614	$674
Total Cost per Km of Line	$53,904	$53,219	$51,767	$50,551	$52,180

In 2019, FHI moved from the group 4 efficiency assessment to group 3. FHI attempts to remain in group 3 annually. Although costs and inflation have grown significantly in the past several years, FHI has been able to manage costs with limited increases to cost per customer or Km of line. With that noted, the 2015 Application did not allow the utility to advance or invest in its systems and buildings and this is requested in the 2025 Application. Costs are planned to increase but in a well-planned and purposeful manner that will allow for adequate tools and advancements for staff and customers.

5.4 SCORECARD METRICS- PUBLIC POLICY RESPONSIVENESS

The following are the scorecard results for Public Policy Responsiveness indicators:

Indicator	2018	2019	2020	2021	2022
Renewable Generation Connection Impact Assessments Completed on Time	100%	100%	100%	100%	---
Scheduled Appointments Met on Time	100%	---	---	100%	100%

Distributors are expected to deliver on obligations mandated by government and regulators. FHI has consistently delivered on public policy initiatives. With the wind down of the Conservation First Framework, there has been limited activity in these categories. FHI will continue to fulfill obligations that are mandated by the government.

5.5 SCORECARD METRICS- FINANCIAL PERFORMANCE

The following are the scorecard results for Financial Performance indicators:

Indicator	2018	2019	2020	2021	2022
Liquidity: Current Ratio	0.50	0.50	0.54	0.51	0.46
Leverage: Total Debt to Equity Ratio	1.19	1.11	1.04	0.99	0.97
Regulatory ROE: Deemed	9.30%	9.30%	9.30%	9.30%	9.30%
Regulatory ROE: Achieved	8.30%	9.10%	8.89%	9.93%	9.25%

Under the RRF, distributors are expected to achieve improvements in efficiency that are sustainable, while maintaining financial viability and earning a fair return. FHI has been very conservative when considering debt and has not been close to the 60/40 debt to equity split built into rates. As investments in the forecast period increase, FHI plans to utilize additional commercial debt as required. FHI has been consistent annually with its achieved ROE which indicates that FHI has been able to contain costs relative to its annual inflationary increase and LRAM recovery included in revenue. During this period there were also significant movements and vacancies within the Executive Leadership team which has skewed cost and net income results. With a full staff compliment, FHI would likely not be able to maintain this level of ROE without this COS Application.

6. CONCLUSION

The 2025-2029 Business Plan for FHI reflects its focus on allowing the utility to catch up on the needs of the business as well as prudently prepare for future customer and system needs. This plan demonstrates a balance of reliability, innovative solutions, and affordability to customers. FHI is committed to its mission, vision, and values, which will allow for continued success and sustainability for FHI and its customers.

Attachment 1 –12

2023 Audited Financial Statements

Financial Statements of

Festival Hydro Inc.

Year ended December 31, 2023

KPMG LLP
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London, ON N6A 5P2
Canada
Telephone 519 672 4880
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INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Festival Hydro Inc.

Opinion

We have audited the financial statements of Festival Hydro Inc. (the Entity), which comprise:

- the statement of financial position as at December 31, 2023
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of material 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, 2023, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards.

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 "***Auditor's Responsibilities for the Audit of the Financial Statements***" section of our auditor's 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 IFRS Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the 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.

Auditor's 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 auditor's 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 auditor's 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 auditor's 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

London, Canada

April 26, 2024

Festival Hydro Inc.

Statement of Financial Position
December 31, 2023, with comparative information for December 31, 2022

	Notes	2023	2022
Assets			
Accounts receivable	6, 22	$ 8,744,272	$ 8,079,655
Unbilled revenue	22	6,915,469	4,783,498
Inventories	7	212,005	177,526
Prepaid expenses		308,819	230,441
Income tax receivable		743,092	511,562
Due from corporations under common control	20	-	127,927
Total current assets		**16,923,657**	**13,910,609**
Non-current assets			
Property, plant and equipment	8	61,152,856	58,854,033
Intangible assets and goodwill	9	2,228,625	1,806,282
Interest rate swap	22	454,755	784,886
Total non-current assets		**63,836,236**	**61,445,201**
Total assets		**80,759,893**	**75,355,810**
Regulatory balances	13	6,468,077	7,503,962
Total assets and regulatory balances		**$ 87,227,970**	**$ 82,859,772**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Financial Position

December 31, 2023, with comparative information for December 31, 2022

	Notes	2023	2022
Liabilities and Equity			
Bank indebtedness	5	$ 3,679,961	$ 3,740,695
Accounts payable and accrued liabilities		9,367,511	8,658,017
Deferred revenue		330,454	273,286
Dividend payable	14, 15, 20	233,750	248,269
Current portion of long-term debt	14, 22	18,850,364	16,328,464
Customer deposits	11	1,256,618	1,016,175
Due to corporations under common control	20	24,254	-
Due to the Corporation of the City of Stratford	20, 22	611,591	630,031
Total current liabilities		**34,354,503**	**30,894,937**
Non-current liabilities			
Deferred revenue		2,953,985	2,641,341
Customer deposits	11	631,651	980,367
Deferred tax liabilities	10	2,617,863	2,381,370
Employee future benefits	12	1,024,453	1,009,878
Long-term debt	14, 22	9,061,648	9,812,012
Total non-current liabilities		16,289,600	16,824,968
Total liabilities		**50,644,103**	**47,719,905**
Share capital	15	15,568,388	15,568,388
Accumulated other comprehensive loss		(109,996)	(54,479)
Retained earnings		19,746,723	18,525,126
Total equity		**35,205,115**	**34,039,035**
Total liabilities and equity		85,849,218	81,758,940
Regulatory balances	13	1,378,752	1,100,832
Total liabilities, equity and regulatory balances		**87,227,970**	**82,859,772**

Commitments and contingencies (note 23)

The accompanying notes are an integral part of these financial statements.

On behalf of the Board:

Director

Director

Festival Hydro Inc.

Statement of Comprehensive Income

Year ended December 31, 2023, with comparative information for 2022

	Notes	2023	2022
Revenues			
Sale of energy	16	$ 63,941,022	$ 55,589,074
Distribution revenue	16	13,332,221	12,174,085
Other income	17	1,114,379	1,118,521
		78,387,622	**68,881,680**
Cost of power purchased		62,317,681	58,141,145
Operating expenses	18	7,490,213	6,759,045
Depreciation and amortization	8,9	2,619,161	2,505,726
		72,427,055	**67,405,916**
Income from operating activities		**5,960,567**	**1,475,764**
Finance income	19	7,070	1,747,174
Finance costs	19	(2,198,576)	(1,574,778)
Income before income taxes		**3,769,061**	**1,648,160**
Income tax expense	10	624,517	1,096,421
Net income		**3,144,544**	**551,739**
Net movement in regulatory balances:			
Net movement in regulatory balances	13	(1,429,562)	2,534,470
Income tax	10,13	130,695	992,021
Net income and net movement in regulatory balances		**1,845,677**	**4,078,230**
Other comprehensive income (loss)			
Items that will not be reclassified to profit and loss:			
Remeasurements of employee future benefits	12	(55,517)	303,258
Tax on remeasurements	10	14,712	(80,363)
Net movement in regulatory balances	13	(14,712)	80,363
Other comprehensive loss		**(55,517)**	**303,258**
Total comprehensive income		**$ 1,790,160**	**$ 4,381,488**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Changes in Equity

Year ended December 31, 2023, with comparative information for December 31, 2022

	Share capital	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2022	**$15,568,388**	**$15,085,495**	**$ (357,737)**	**$ 30,296,146**
Net income after net movement in regulatory balances	–	4,078,230	–	4,078,230
Other comprehensive loss	–	–	303,258	303,258
Dividends, paid or payable	–	(638,599)	–	(638,599)
Balance at December 31, 2022	**$15,568,388**	**$18,525,126**	**$ (54,479)**	**$ 34,039,035**
Balance at January 1, 2023	**$15,568,388**	**$18,525,126**	**$ (54,479)**	**$ 34,039,035**
Net income after net movement in regulatory balances	–	1,845,677	–	1,845,677
Other comprehensive loss	–	–	(55,517)	(55,517)
Dividends, paid or payable	–	(624,080)	–	(624,080)
Balance at December 31, 2023	**$15,568,388**	**$19,746,723**	**$ (109,996)**	**$ 35,205,115**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Cash Flows

Year ended December 31, 2023, with comparative information for December 31, 2022

Cash provided by (used in)	Notes	2023	2022
Operating activities			
Net income after net movement in regulatory balances		$1,845,677	$4,078,230
Adjustments for			
Depreciation - property, plant and equipment	8	2,369,747	2,243,817
Amortization - intangible assets	9	249,414	261,909
Amortization of deferred revenue		(76,869)	(76,869)
Employee future benefits		(40,942)	(48,508)
Net finance costs	19	2,191,506	(172,396)
Income tax expense	10	624,517	1,096,421
		7,163,050	7,382,604
Changes in non-cash operating working capital			
Accounts receivable		(664,617)	45,246
Unbilled revenue		(2,131,971)	447,273
Inventories		(34,481)	(14,083)
Prepaid expenses		(78,379)	126,841
Accounts payable and accrued liabilities		709,494	(1,244,625)
Due from related parties		151,502	210,656
Due from the City of Stratford		(18,678)	(1,209)
Dividends declared		(14,519)	(252,287)
Customer deposits		(108,272)	232,689
		(2,189,921)	(449,499)
Regulatory balances	13	1,298,867	(3,526,490)
Interest paid	19	(1,868,445)	(1,574,778)
Interest received		7,070	23,340
Income tax paid, net of refund		(608,888)	(5,476)
Net cash from operating activities		**3,801,733**	**1,849,701**
Investing activities			
Purchase of property, plant and equipment	8	(4,998,921)	(3,983,941)
Purchase of intangible assets	9	(341,397)	(333,350)
Net cash used in investing activities		(5,340,318)	(4,317,291)
Financing activities			
Contributions received from customers, net of repayments		466,382	341,267
Dividends	14	(638,599)	(890,886)
Proceeds from long-term debt		2,500,000	-
Repayment of long-term debt		(728,464)	(707,718)
Net cash used in financing activities		1,599,319	(1,257,337)
Decrease in bank indebtedness during the year		60,734	(3,724,927)
Bank indebtedness, beginning of the year		(3,740,695)	(15,768)
Bank indebtedness, end of the year		**$ (3,679,961)**	**$ (3,740,695**

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

Festival Hydro Inc. (the "Corporation") is a wholly owned subsidiary of the City of Stratford. The Corporation was incorporated on July 11, 2000 under the Business Corporations Act (Ontario) pursuant to Section 142 of the Electricity Act Laws of the Province of Ontario, Canada. The address of the Corporation's registered office is 187 Erie Street, Stratford, Ontario, Canada.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the City of Stratford and the towns of Brussels, Dashwood, Hensall, Seaforth, St. Marys and Zurich, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the Ontario Energy Board and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2023.

2. Basis of preparation:

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). These financial statements were approved by the Board of Directors on April 25, 2024.

(b) Basis of measurement

The financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

(d) Use of estimates and judgements

Information about judgements made in applying accounting policies that have an effect on the amounts recognized in the financial statements is included in the following notes:

Note 3(o)	Determination of the performance obligation for capital contribution and the related amortization period
Note 3(p)	Whether an arrangement contains a lease
Note 6	Estimate for impairment for uncollected amounts, based on the lifetime expected credit losses
Note 8	Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment.
Note 9	Intangible assets: useful lives and goodwill impairment testing.
Note 12	Measurement of the defined benefit obligation – actuarial assumptions
Note 23	Recognition and measurement of commitments and contingencies.

2. Basis of preparation (continued)

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board, under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, amongst other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill certain classes of customers for the debt retirement charges. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

(f) Rate setting

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a "Cost of Service" ("COS") rate application with the OEB where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each class. The COS application is reviewed by the OEB and interveners on record. Rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years, the Corporation has chosen to file a Price Cap Incentive Rate Mechanism ("IRM") application. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

2. Basis of preparation (continued)

(f) Rate setting (continued)

Distribution revenue (continued)

Festival filed its 2022 IRM application for distribution rates and was approved new rates by the OEB effective January 1, 2022. The Corporation's approved adjustment to distribution rates was 3.00%, as a result of an OEB approved inflation factor of 3.30%, less a stretch factor of 0.30% determined by the relative efficiency of the Corporation. The application included the approval of rate riders for the disposition of certain deferral and variance balances.

Festival filed its 2023 IRM application for distribution rates and was approved new rates by the OEB effective January 1, 2023. The Corporation's approved adjustment to distribution rates was 3.10%, as a result of an OEB approved inflation factor of 3.70%, less a stretch factor of 0.60% determined by the relative efficiency of the Corporation. The application included the approval of rate riders for the disposition of certain deferral and variance balances.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity and the global adjustment. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

3. Material accounting policies:

The accounting policies set out below have been applied consistently for both years presented in these financial statements in accordance with IFRS.

(a) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income (“OCI”). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. Material accounting policies (continue):

(a) Regulatory balances (continued)

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts. On the statement of cash flows, cash and cash equivalents includes bank overdrafts (revolving credit facility) that are repayable on demand and form an integral part of the Corporation's cash management.

(c) Financial instruments

All financial assets and financial liabilities are classified as "Amortized cost". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. The Corporation uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the statement of financial position:

- Cash and cash equivalents are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method, less expected credit loss allowance. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Amortized cost" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount approximates fair value due to the short maturity of these instruments.

- Accounts payable are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Customer deposits are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Long-term debts are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts of the debt are carried at amortized cost, based on the fair value of the debt at issuance, which was the fair value of the consideration received adjusted for transaction costs.

3. Material accounting policies (continued):

(d) Derivatives

The Corporation holds derivative financial instruments to manage rate risk exposures. Derivatives are initially recognized at fair value; any directly attributable transaction costs are recognized in the Statement of Comprehensive Income as incurred as a change in interest rate swap. Subsequent to initial recognition, derivatives are measured at fair value, using Level 2 inputs, and changes therein are recognized in the Statement of Comprehensive Income.

Hedge accounting has not been used in the preparation of these financial statements.

(e) Fair value measurements

The Corporation utilizes valuation techniques that maximize the use of observable inputs to minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included in Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

(f) Inventories

Inventories are stated at lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis, net of a provision for obsolescence, as applicable. The Corporation classifies all major construction related component of its electricity distribution infrastructure to property, plant and equipment.

3. Material accounting policies (continued):

(g) Property, plant and equipment ("PP&E")

Items of property, plant and equipment used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, or, where the item is transferred from customers, its fair value, less accumulated depreciation and accumulated impairment losses. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour and any other costs directly attributable to bringing the asset to a working condition for its intended use. Borrowing costs on qualifying assets are capitalized as part of the cost of the asset and are based on the Corporation's cost of borrowing. For construction projects of less than one year in length, borrowing costs are not capitalized unless specific identifiable loans are acquired for the express purpose of financing a specific construction activity.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing part of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. The carrying amount of the replaced part is derecognized.

The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred. Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not amortized until the project is complete and in service.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives. Depreciation methods, useful lives and residual values are reviewed at each reporting date and adjusted if appropriate. The estimated useful lives for the current and comparative years are as follows:

Buildings	10 to 60 years
Distribution substation equipment	30 to 60 years
Distribution system equipment	30 to 60 years
Transformers	35 to 40 years
Meters	15 to 40 years
Other capital assets	4 to 20 years

Other capital assets include vehicles, office and computer equipment.

3. Material accounting policies (continued):

(g) Property, plant and equipment ("PP&E") (continued)

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized within other income in the statement of comprehensive income.

(h) Intangible assets

Intangible assets include goodwill, computer software and capital contributions paid under capital cost recovery agreements ("CCRAs").

(i) Goodwill

Goodwill represents the excess of cost over fair value of net assets which arose upon amalgamation of the former electrical distribution entities. Goodwill is measured at cost less accumulated impairment losses.

(ii) Computer software

Computer software acquired prior to January 1, 2014, is measured at deemed cost less accumulated depreciation. All other software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

(iii) Capital contributions paid under capital cost recovery agreements

Capital contributions paid under CCRAs are measured at cost less accumulated amortization and accumulated impairment losses.

(iv) Amortization

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. The estimated useful lives for the current and comparative years are:

Computer software	5 to 10 years
CCRAs	15 to 25 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted if appropriate.

3. Material accounting policies (continued):

(i) Impairment

(i) Financial assets measured at amortized cost

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

The carrying amounts of the Corporation's non-financial assets, other than regulatory assets, inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill, the recoverable amount is estimated as at December 31 of each year.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The Corporation has determined that it has one cash generating unit. The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to cash-generating units that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

3. Material accounting policies (continued):

(j) Employee benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("Fund"). The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

OMERS is a defined benefit plan, however, as the plan assets and pension obligations are not segregated in separate accounts for each member entity, sufficient information is not available to enable the Corporation to directly account for the plan. As such, the plan has been accounted for as a defined contribution plan. The contribution payable is recognized as an employee benefit expense in the statement of comprehensive income in the period in which the service was rendered by the employee, since it is not practicable to determine the Corporation's portion of person obligations of the fair value of plan assets.

(ii) Employee future benefits, other than pension

The Corporation has an unfunded benefit plan providing post-employment benefits (other than pension) to its employees. The Corporation provides its retired employees (20 years service; less than age 65) with life insurance and medical benefits beyond those provided by government sponsored plans. Life insurance is provided for current retirees including those over age 65.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses, are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Deferred revenue and assets transferred from customers

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded under current liabilities as customer deposits. Once the distribution system asset is completed or modified, as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction. The contributions in aid of construction account, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is reported as deferred revenue, and is amortized to other income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

3. Material accounting policies (continued):

(l) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts, calculated using OEB prescribed interest rates, and owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability. Annually, accrued interest is applied directly to the customers' accounts.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when the Corporation no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

(m) Revenue recognition

(i) Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

(ii) Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

3. Material accounting policies (continued):

(m) Revenue Recognition (continued)

(ii) Capital contributions (continued)

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

(iii) Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

(n) Leased assets

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

3. Material accounting policies (continued):

(n) Leased assets (continued)

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

(o) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on customer deposits, the demand notes payable, revolving credit facility and long-term borrowings.

Changes in the fair value of interest rate swap agreements are recorded either in finance income, or costs, depending on whether an unrealized gain or loss is required.

(p) Income taxes

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to other comprehensive income or items recognized directly in equity, in which case, it is recognized in accumulated comprehensive income or retained earnings, respectively.

Current tax is the tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

3. Material accounting policies (continued):

(p) Income taxes (continued)

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit or debt balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of comprehensive income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of comprehensive income.

(q) Changes in accounting standards

Definition of Accounting Estimates (Amendments to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors (IAS 8))

In February 2021, the IASB issued amendments to IAS 8 to introduce a definition of “accounting estimates” and include other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied prospectively.

Disclosure of Accounting Policies (Amendments to IAS 1 Presentation of Financial Statements (IAS 1))

In February 2021, the IASB issued amendments to IAS 1 requiring an entity to disclose its material accounting policies, rather than its significant accounting policies. Additional amendments were made to explain how an entity can identify a material accounting policy. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12 Income Taxes (IAS 12))

In May 2021, the IASB issued amendments to IAS 12. The amendments clarify how companies should account for deferred tax on certain transactions such as leases and decommissioning obligations. The amendments narrow the scope of the initial recognition exemption, so that it does not apply to transactions that give rise to equal and offsetting temporary differences. As a result, companies will need to recognize both a deferred tax asset and a deferred tax liability when accounting for such transactions. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Effective January 1, 2023, the Corporation adopted these amendments, with no impact on the financial statements.

4. Future accounting pronouncements:

The IASB has issued a number of standards and amendments to existing standards that are not yet effective. The Corporation has determined that the following amendment could have an impact on the Corporation's financial statements when adopted.

Disclosure Classification of Liabilities as Current or Non-current (Amendments to IAS 1)

In January 2020, the IASB issued amendments to IAS 1 relating to the classification of liabilities as current or noncurrent. Specifically, the amendments clarify one of the criteria in IAS 1 for classifying a liability as non-current - that is, the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. This right may be subject to compliance with covenants. After reconsidering certain aspects of the 2020 amendments, in October 2022, the IASB issued Non-current Liabilities with Covenants (Amendments to IAS 1), reconfirming that only covenants with which a company must comply on or before the reporting date affect the classification of a liability as current or non-current. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, with early adoption permitted. The amendments are to be applied retrospectively.

The Corporation anticipates that the adoption of these accounting pronouncements will not have a material impact on the Corporation's financial statements.

5. Bank indebtedness:

	2023	2022
Cash	$ 120,039	$ 539,305
Revolving credit facility, revolving in increments of $10,000 with a limit of $10,000,000, charging interest at Canadian bank prime rates	(3,800,000)	(4,280,000)
Bank indebtedness	**$ (3,679,961)**	**$ (3,740,695)**

6. Accounts receivable:

	2023	2022
Energy, water and sewer	$ 7,708,701	$ 6,523,810
Other	1,035,571	1,555,845
Total	**$ 8,744,272**	**$ 8,079,655**

Included in accounts receivable is $1,478,832 (2022 - $1,230,333) of customer receivables for water consumption and sewer ("water & sewer") that the Corporation bills and collects on behalf of the City of Stratford and the Town of St. Marys. As the Corporation does not assume liability for collection of these amounts, any amount related to City of Stratford and Town of St. Marys water & sewer charges that are determined to be uncollectible are charged to the City of Stratford and Town of St. Marys, respectively. At year end, there is nil (2022 - nil) included in the provision for impairment for uncollectable amounts relating to water and sewer.

7. Inventories:

The amount of inventories consumed by the Corporation and recognized as an expense during 2023 was $130,666 (2022 - $149,137). During 2023, an amount of nil (2022 – nil) was recorded as an expense for the write-down of obsolete or damaged inventory to net realizable value.

8. Property, plant and equipment:

a) Cost or deemed cost

	Land and buildings	Distribution & substation equipment	Other distribution system equipment	Transformer station	Total
Balance at January 1, 2022	$3,133,922	$50,046,755	$3,116,334	$14,192,427	$70,489,438
Additions	357,228	3,022,647	281,971	86,263	$ 3,748,109
Transfers	-	-	235,832	-	$235,832
Disposals/retirements	(27,578)	(297,300)	(375,808)	-	($700,686)
Balance at December 31, 2022	**$3,463,572**	**$52,772,102**	**$3,258,329**	**$14,278,690**	**$73,772,693**
Balance at January 1, 2023	$3,463,572	$52,772,102	$3,258,329	$14,278,690	$73,772,693
Additions	1,060,506	2,876,421	420,018	212,043	$ 4,568,988
Work in Progress	-	96,468	3,114	-	$99,582
Disposals/retirements	(7,732)	(244,489)	(227,295)	-	($479,516)
Balance at December 31, 2023	**$4,516,346**	**$55,500,502**	**$3,454,166**	**$14,490,733**	**$77,961,747**

b) Accumulated depreciation

	Land and buildings	Distribution & substation equipment	Other distribution system equipment	Transformer station	Total
Balance at January 1, 2022	$ 427,301	$ 9,160,998	$1,232,991	$2,554,239	$13,375,529
Depreciation	120,660	1,491,865	285,635	345,657	$ 2,243,817
Disposals/retirements	(27,578)	(297,300)	(375,808)	-	($700,686)
Balance at December 31, 2022	$ 520,383	$10,355,563	$1,142,818	$2,899,896	$14,918,660
Balance at January 1, 2023	$ 520,383	$ 10,355,563	$1,142,818	$2,899,896	$14,918,660
Depreciation	156,767	1,549,351	305,356	358,273	$ 2,369,747
Disposals/retirements	(7,732)	(244,489)	(227,295)	-	($479,516)
Balance at December 31, 2023	$ 669,418	$11,660,425	$1,220,879	$3,258,169	$ 16,808,891

c) Carrying amounts

	Land and buildings	Distribution & substation equipment	Other distribution system equipment	Transformer station	Total
December 31, 2022	$2,943,189	$42,416,539	$2,115,511	$11,378,794	$58,854,033
December 31, 2023	$3,846,928	$43,840,077	$2,233,287	$11,232,564	$61,152,856

d) Borrowing costs

During the year, no borrowing costs (2022 – nil) were capitalized as part of the cost of property, plant and equipment.

9. Intangible assets and goodwill:

a) Cost or deemed cost

	Goodwill	Computer software	Land Rights	CCRA's	Total
Balance at January 1, 2022	$515,359	$ 1,418,972	$ 3,150	$ 966,935	$ 2,904,416
Additions	-	111,889	-	-	111,889
Work in Progress	-	221,461	-	-	221,461
Disposals	-	(312,506)	-	-	(312,506)
Balance at December 31, 2022	**$ 515,359**	**$ 1,439,816**	**$ 3,150**	**$ 966,935**	**$ 2,925,260**
Balance at January 1, 2023	$ 515,359	$ 1,439,816	$ 3,150	$ 966,935	$ 2,925,260
Additions	-	341,398	-	-	341,398
Work in Progress	-	330,359	-	-	330,359
Disposals	-	(207,569)	-	-	(207,569)
Balance at December 31, 2023	**$ 515,359**	**$ 1,904,004**	**$ 3,150**	**$ 966,935**	**3,389,448**

b) Accumulated amortization

	Goodwill	Computer software	Land Rights	CCRA's	Total
Balance at January 1, 2022	**$ -**	**$ 741,083**	**$ -**	**$ 428,492**	**$ 1,169,575**
Amortization	-	207,436	-	54,473	261,909
Disposals	-	(312,506)	-	-	(312,506)
Balance at December 31, 2022	$ -	**$ 636,013**	$ -	**$ 482,965**	**$ 1,118,978**
Balance at January 1, 2023	$ -	$ 636,013	$ -	$ 482,965	$ 1,118,978
Amortization	-	194,941	-	54,473	249,414
Disposals	-	(207,569)	-	-	(207,569)
Balance at December 31, 2023	$ -	**$ 623,385**	$ -	**$ 537,438**	**$ 1,160,823**

c) Carrying amounts

	Goodwill	Computer software	Land Rights	CCRA's	Total
December 31, 2022	$ 515,359	$ 803,803	$ 3,150	$ 483,970	$ 1,806,282
December 31, 2023	$ 515,359	$ 1,280,619	$ 3,150	$ 429,497	$ 2,228,625

d) Goodwill impairment

Management has determined that the Corporation's rate regulated operations are one cash generating unit. Therefore, the goodwill was allocated to the Corporation as a whole. The annual impairment test is based on the Corporation's value in use.

9. Intangible assets and goodwill:

d) Goodwill impairment (continued)

A detailed valuation of the Corporation was undertaken during 2023 based on preliminary financial results of the Corporation as at December 31, 2023. Cash flows were projected based on actual operating results and the cost of capital and rate of return as approved in the 2015 Cost of Service application. A discounted cash flow model was utilized based on free cash flows for 20 years, followed by a terminal value calculated based on a steady-state cash flow, with the terminal value within range of market-based terminal multiples. The recoverable amount of the Corporation was determined to be greater than the carrying value of goodwill and no impairment was recorded as at December 31, 2023 or December 31, 2022.

10. Income taxes:

Income tax expense	**2023**	**2022**
Current tax expense:		
Current year	$ 373,312	$ 160,945
Prior year	-	(56,545)
Total current tax expense	373,312	104,400
Deferred tax expense:		
Change in recognized deductible temporary differences	251,205	992,021
Total current and deferred income tax in profit or loss, before movement of regulatory balance	624,517	1,096,421
Other comprehensive income:		
Employee future benefits	(14,712)	80,363
Total current and deferred tax, before movement in regulatory balances	609,805	1,176,784
Net movement in regulatory balances	(115,983)	(1,072,384)
Income tax expense recognized in statement of comprehensive Income	$493,822	**$104,400**

Reconciliation of effective tax rate

	2023	**2022**
Income before taxes	$2,283,982	$4,486,834
Canada and Ontario statutory income tax rates	26.5%	26.5%
Expected tax provision on income tax at statutory rates	605,255	1,189,011
Increase (decrease) in income tax resulting from:		
Permanent differences	2,060	2,212
Recognized deductible temporary difference due from customers	(115,983)	(1,072,384)
Other	2,490	(14,439)
Income tax expense	**$ 493,822**	**$ 104,400**

10. Income taxes (continued):

	2023	2022
Deferred tax assets (liabilities):		
Property, plant, equipment and intangible assets	($2,820,051)	($2,488,634)
Employee future benefits	271,480	267,618
Unrealized gain on interest rate swap	(120,510)	(207,995)
Other	51,218	47,641
	($2,617,863)	**($2,381,370)**

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers as well as construction deposits. These customer deposits bear interest at the OEB's prescribed interest rate, which is the Bank of Canada's prime business rate less 2%.

Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service. Due to the demand nature of these deposits, they are classified as current liabilities.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to deferred revenue.

Customer deposits comprise:

	2023	2022
Electricity deposits	$ 911,071	$ 957,164
Construction deposits	977,198	1,039,378
Total customer deposits	**$1,888,269**	**$1,996,542**
Consisting of:		
Short-term	$ 1,256,618	$ 1,016,175
Long-term	631,651	980,367

12. Employee future benefits:

(a) Employee future benefits, other than pension

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Corporation has reflected its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these financial statements. The accrued benefit liability and the corresponding expense were based on results and assumptions determined by actuarial valuation as at December 31, 2023.

12. Employee future benefits (continued):

(a) Employee future benefits, other than pension (continued)

Changes in the present value of the defined benefit unfunded obligation and the accrued benefit liability:

	2023	2022
Defined benefit obligation, beginning of year	$ 1,009,878	$ 1,361,643
Included in profit or loss:		
Current service cost	23,310	36,217
Interest cost	48,324	38,994
	71,634	75,211
Included in OCI:		
Actuarial (gains) losses arising from changes in financial assumptions	55,517	(303,258)
Benefits paid during the year	(112,576)	(123,718)
Defined benefit obligation, end of year	**$1,024,453**	**$1,009,878**

The significant actuarial assumptions used in the valuation are as follows:

	2023	2022
Discount rate	4.60%	5.05%
Rate of compensation increase	3.30%	3.30%
Initial health care cost trend rate	4.90%	4.70%
Initial dental cost trend rate	5.10%	4.90%
Year that rate reaches the rate it is assumed to be	2040	2040
Cost trend rate declines to	4.00%	4.00%

Significant actuarial assumptions for benefit obligation measurement purposes are the discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes in the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely these changes in assumptions would occur in isolation from each other. The approximate effect on the accrued benefit obligation of the entire plan and the estimated net benefit expense of the entire plan if the health care trend rate assumption was increased or decreased by 1%, and all other assumptions were held constant, is as follows:

	2023	2022
Benefit Obligation, end of year	$1,024,453	$1,009,878
1% increase in health care trend rate	33,300	26,900
1% decrease in health care trend rate	(29,900)	(24,300)
1% increase in discount rate	(105,500)	(96,500)
1% decrease in discount rate	130,900	119,000

(b) Pension plan

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System. The plan is a multi-employer, contributory defined benefit pension plan. In 2023, the Corporation made employer contributions of $404,465 to OMERS (2022 - $365,116). The Corporation's net benefit expense has been allocated as follows:

- $145,607 (2022 - $138,744) capitalized as part of PP&E
- $214,366 (2022 - $186,209) charged to operating expenses
- $44,492 (2022 - $40,163) charged to CDM and billable work

12. Employee future benefits (continued):

(b) Pension plan (continued)

As at December 31, 2023, OMERS states that their plan was 97% funded (2022 – 95%). OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. The Corporation's contributions represent less than 1% of the total annual contributions to the OMERS plan.

13. Regulatory assets and liabilities:

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

In the tables below, the "Additions" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts collected through rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of reclassification between the regulatory debit and credit balances. For the years ended December 31, 2023 and 2022, the Corporation did not record any impairments related to regulatory debit balances.

	January 1, 2023	Transactions	Recovery/ reversal	Other Movements	December 31, 2023	Notes
Regulatory deferral account debit balances						
Settlement (Group 1) variances	$ 5,087,624	$ (1,275,857)	$ (43,998)	$ 97,326	$ 3,865,095	(1)
Stranded meters	2,313	(2,313)	-	-	-	(2)
LRAM	24,647	85,846	(9,819)	4,955	105,629	(1)
Deferred Taxes	2,381,370	115,983	-	-	2,497,353	(4)
Rate application costs	8,008	(8,008)	-	-	-	(3)
	$ 7,503,962	**$ (1,084,349)**	**$ (53,817)**	**$ 102,281**	**$ 6,468,077**	

	January 1, 2022	Transactions	Recovery/ reversal	Other Movements	December 31, 2022	Notes
Regulatory deferral account debit balances						
Settlement (Group 1) variances	$ 2,939,939	$ 386,141	$ (313,926)	$ 2,075,470	$ 5,087,624	(1)
Stranded meters	2,292	21	-	-	2,313	(2)
LRAM	268,628	(244,237)	256	-	24,647	(1)
Deferred Taxes	1,308,987	1,072,383	-	-	2,381,370	(4)
Rate application costs	8,008	-	-	-	8,008	(3)
	$ 4,527,854	**$1,214,308**	**$ (313,670)**	**$ 2,075,470**	**$ 7,503,962**	

13. Regulatory assets and liabilities (continued):

	January 1, 2023	Transactions	Recovery/ reversal	Other Movements	December 31, 2023	Notes
Regulatory deferral account credit balances						
Settlement (Group 1) variances	$ (547,437)	(59,260)	$ 53,817	$ (97,326)	$ (650,206)	(1)
IFRS transition adjustments	(10,783)	10,783	-	-	-	(5)
LRAM	-	(21,882)	-	(4,955)	(26,837)	(1)
PILS	(542,612)	(159,097)	-	-	(701,709)	
	$ (1,100,832)	**$ (229,456)**	**$ 53,817**	**$ (102,281)**	**$ (1,378,752)**	

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	January 1, 2022	Transactions	Recovery/ reversal	Other Movements	December 31, 2022	Notes
Regulatory deferral account credit balances						
Settlement (Group 1) variances	$ (1,286,576)	2,500,939	$ 313,670	$ (2,075,470)	$ (547,437)	(1)
IFRS transition adjustments	(10,783)	-	-	-	(10,783)	(5)
PILS	(434,218)	(108,394)	-	-	(542,612)	
	$ (1,731,577)	**$ 2,392,545**	**$ 313,670**	**$ (2,075,470)**	**$ (1,100,832)**	

1) The changes in settlement (Group 1) and LRAM balances outstanding from December 31, 2022 were approved for disposition as part of the 2023 IRM application with rates effective January 1, 2023 to be collected over a 12-month period.

2) As part of the 2015 COS application, the OEB approved the disposition of stranded meters through a rate rider effective May 1, 2015 (implemented June 1, 2015) with recovery over a 7-month period ending December 31, 2015. Since the residual balance was trivial, it was cleared to $nil at the end of 2023.

3) The 2015 COS rate application costs were approved for recovery by the OEB and have been amortized over a forty-three-month period ending December 31, 2019. Since the residual balance was trivial, it was cleared to $nil at the end of 2023.

4) Disposition is not requested for the deferred tax balance as it is being reversed through timing differences in the recognition of deferred tax assets. No carrying charges are calculated on this balance.

5) As part of the 2015 COS application, the OEB approved the disposition of the account 1575/76 IFRS transition account balance used to record the difference arising on adoption of new asset useful lives and overhead rates and write off of end-of-life assets. These account balances were included as a rate rider effective May 1, 2015 (implemented June 1, 2015) and were recovered over a 7-month period ended December 31, 2015. Since the residual balance was trivial, it was cleared to $nil at the end of 2023.

Carrying charges are applied to all regulatory account balances at the OEB prescribed interest rates, with the exception of the deferred tax assets on which no carrying charges are applied.

As part of the Corporation's 2023 IRM application, the change in debit and credit balance settlement (Group 1) variance accounts occurring during fiscal 2021 were approved as part of 2023 distribution rates for recovery over a 12-month period commencing January 1, 2023. As such, the risk associated with the recovery of variance accounts is limited to the incremental value of non-settlement variances arising since 2021.

14. Long-term debt:

Long-term debt consists of the following:

	2023	2022
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 1.81% on bankers' acceptances, payable in monthly principal instalments of approximately $40,000 plus interest, increasing by $1,000 yearly until maturity on May 31, 2038, secured by a general security agreement, subject to a swap agreement as outlined below.	9,369,000	9,875,000
Royal Bank revolving term loan, bearing variable interest at 5.39%, plus a stamping fee of 1.51% on bankers' acceptances, interest only payments until December 31, 2024, subject to a swap agreement as outlined below.	2,500,000	-
Royal Bank loan, bearing interest at 2.62%, payable in monthly principal instalments of $19,768, maturing November 25, 2025, secured by a general security agreement.	443,012	665,476
Notes payable to shareholder, bearing interest at 7.25% per annum, with interest payments only, due on demand, unsecured.	15,600,000	15,600,000
	27,912,012	**26,140,476**
Less: current portion	18,850,364	16,328,464
Long-term debt	**$9,061,648**	**$9,812,012**

Interest rate swaps

The Corporation entered into an interest rate swap agreement on a notional principal of $14,000,000 effective May 31, 2013, which matures May 31, 2038. The swap is a receive-variable, pay-fixed swap with the Royal Bank. This agreement has effectively converted variable interest rates to an effective fixed interest rate of 2.93% plus stamping fee of 0.42% on the Royal Bank revolving term loan. The stamping fee is subject to change every 10 years, with the first maturity occurred on May 31, 2023. On this day, the stamping fee changed from 0.42% to 1.81%.

The Corporation entered into a swap agreement on a notational principal of $2,500,000. The swap is a receive-variable, pay fixed swap with Royal Bank. This agreement has effectively converted variable interest rates to an effective fixed interest rate of 5.39% plus a stamping fee of 1.51%.

The Corporation has determined these swaps do not meet the standard to apply hedge accounting. Since the standard is not met, the interest rate swap contracts have been recorded at their fair value at December 31, 2023 with the combined unrealized loss for the year of $330,131 (2022 – gain of $1,723,834) recorded as finance cost in the statement of comprehensive income. The Corporation uses Level 2 inputs to determine fair value.

14. Long-term debt continued:

Reconciliation of movements of liabilities to cash flows arising from financing activities:

	Current and long-term debt	Dividends payable	Retained earnings	Total (financing cash flows)
Balance at January 1, 2023	$ 26,140,476	$ 248,269	$ 18,525,126	
Dividends paid	-	(248,269)	(390,330)	$ (638,599)
Proceeds from long-term debt	2,500,000	-	-	2,500,000
Repayments of long-term debt	(728,464)	-	-	(728,464)
Total changes from financing cash flows	**$ 1,771,536**	**$ (248,269)**	**$ (390,330)**	**$ 1,132,937**
Dividend declared but not paid	-	233,750	(233,750)	-
Net income after net movements in regulatory balances	-	-	1,845,677	1,845,677
Balance at December 31, 2023	$ 27,912,012	$ 233,750	$ 19,746,723	$ 2,978,614

15. Share capital:

	2023	2022
Authorized:		
Unlimited Class A special shares, non-cumulative, 5.0%		
Unlimited Class B special shares		
Unlimited Common shares		
Issued:		
6,100 Class A special shares	$ 6,100,000	$ 6,100,000
6,995 Common shares	9,468,388	9,468,388
	$ 15,568,388	**$15,568,388**

Dividends paid on the 6,100 class A special shares during the year totalled $152,500 (2022 - $152,500). Dividends paid on the 6,995 common shares during the year totalled $471,580 (2022 - $486,099). A common share dividend was declared on December 15, 2023 and is payable on all common shares on record at December 31, 2023, with the dividend to be paid in 2024. The dividend amount payable at December 31, 2023 is $233,750 (2022 - $248,269).

16. Revenue from Contracts with Customer:

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. Sources of revenue are as documented in the table below.

	2023 Sale of Energy	2023 Distribution Revenue	2022 Sale of Energy	2022 Distribution Revenue
Residential	$ 17,732,062	$ 7,097,764	$ 17,226,468	$ 6,928,900
Commercial	42,664,867	5,744,876	35,806,876	4,757,459
Large Users	2,849,463	323,578	2,762,863	314,993
Other	694,630	166,003	(207,133)	172,733
	$ 63,941,022	**$ 13,332,221**	**$ 55,589,074**	**$ 12,174,085**

17. Other income:

	2023	2022
Collection, late payment and other service charges	$ 101,740	$ 124,331
Pole attachment and other rental income	166,816	108,836
Miscellaneous	819,567	853,362
Solar generation	26,256	31,992
	$ 1,114,379	**$ 1,118,521**

Collection, late payment and other service charges are based on service charge rates and retailer rates as approved by the OEB. Pole attachment and other rentals consist primarily of pole attachment charges and charges for office and service centre space.

Miscellaneous includes revenues from City of Stratford and Town of St. Marys water and sewage billing services, street lighting services, management fees charged to Festival Hydro Services Inc. and other revenue sources.

18. Operating expenses:

	2023	2022
Salaries and benefits	$ 3,806,285	$ 3,329,138
External services	2,215,081	1,924,106
Materials and supplies	540,790	584,647
Other support costs	928,057	921,154
	$ 7,490,213	**$ 6,759,045**

19. Finance income and costs:

	2023	2022
Interest income on loan to corporation under common control	$ 3,398	$ 10,862
Interest on bank account	3,531	12,036
Interest on written off trade receivables	141	442
Unrealized gain on interest rate swap	-	1,723,834
Finance income	**$ 7,070**	**$ 1,747,174**
Interest expense on demand notes payable	$1,131,000	$1,131,000
Interest expense on long-term debt	479,139	338,185
Interest on revolving credit facility	190,782	84,552
Interest expense on deposits	62,701	21,041
Other interest expense	4,823	-
Unrealized loss on interest rate swap	330,131	-
Finance costs	**$ 2,198,576**	**$ 1,574,778**
Net finance income (costs)	**$ (2,191,506)**	**$ 172,396**

20. Related party transactions:

a) *Parent and ultimate controlling party*

The parent and sole shareholder of the Corporation is the Corporation of the City of Stratford (the "City"). The City of Stratford produces financial statements that are available for public use.

b) *Key management personnel*

The key management personnel of the Corporation has been defined as members of its Board of Directors and executive management team members. Total compensation of key management in 2023 was $902,559 (2022 - $833,946).

20. Related party transactions (continued):

c) *Transactions with the Corporation of the City of Stratford*

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts, with the parent, the City of Stratford, for the years ended December 31:

	2023	2022
Revenues:		
Energy sales	$ 1,342,294	$ 1,475,873
Water and sewer administration fee	539,320	499,716
Street lighting services	12,617	18,760
Service centre space rental	36,851	33,477
Total revenues	$ 1,931,082	$ 2,027,826
Expenses:		
Interest on demand notes payable	$ 1,131,000	$ 1,131,000
Property taxes	149,822	121,157
Tree trimming	56,980	54,494
Total expenses	$ 1,337,802	$ 1,306,651

	December 31, 2023	December 31, 2022
Receivable balances:		
Accounts receivable	$ 366,769	$ 365,293
Payable balances:		
Accounts payable and accrued charges	$ 978,360	$ 995,324
Demand notes payable	15,600,000	15,600,000
Dividends payable	233,750	248,269
Total payables	$16,812,110	$16,843,593

The net amount owing to the Corporation of the City of Stratford for accounts receivable, accounts payable and accrued charges is $611,591 (2022 - $630,031).

Dividends paid or payable	$ 624,080	$ 638,599

20. Related party transactions (continued):

d) Transactions with corporations under common control of the parent

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts, with Festival Hydro Services Inc., a wholly-owned subsidiary of the City of Stratford, for the years ended December 31:

	2023	2022
Revenues:		
Operational services	$ 31,538	$ 33,397
Management fee	60,982	64,851
Office and fibre room rentals	1,347	1,470
Joint pole rentals	57,384	55,308
Interest earned	3,398	10,862
Energy sales	30,817	28,689
Water billing and collection services	76,358	75,120
Total revenues	$261,824	$269,697
Expenses:		
Fiber and WIFI services	$154,148	$154,148
Information technology and management services	330,947	273,165
Total expenses	$485,095	$427,313

Receivable balance:		
	December 31, 2023	**December 31, 2022**
Due from(to) corporations under common control	$(24,254)	$127,927

21. Capital management:

The Corporation's main objectives when managing capital is to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents or committed credit facilities) to meet the needs of the business;
- ensure compliance with covenants related to its credit facilities; and
- prudent management of its capital structure with regard to recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios. The Corporation manages capital by preparing short-term and long-term cash flow forecasts, statements of financial position and comprehensive statements of income. In addition, the Corporation accesses its revolving credit facility to fund net periodic net cash outflows and to maintain available liquidity.

There have been no changes in the Corporation's approach to capital management during the year. As at December 31, 2023, the Corporation's definition of capital included borrowings under its revolving credit facility, long-term debt and obligations including the current portion thereof, and equity, and had remained unchanged from the definition as at December 31, 2022. As at December 31, 2023, equity amounted to $35,205,115 (2022 - $34,039,035), borrowings in the form of demand notes payable and long-term debt, including the current portion thereof, amounted to $27,912,012 (2022 - $26,140,476) and the revolving credit facility amounted to $3,681,457 (2022 - $3,720,132).

21. Capital management (continued):

The OEB regulates the amount of deemed interest on debt and rate of return that may be recovered by the Corporation, through its electricity distribution rates, in respect of its regulated electricity distribution business. The OEB permits such recoveries on the basis of a deemed capital structure represented by 60% debt and 40% equity. The actual capital structure and finance costs for the Corporation may differ from the OEB deemed structure.

The Corporation is subject to debt agreements that contain various covenants. The Corporation's credit agreement with Royal Bank provides a revolving demand facility, letter of guarantee which is posted with the IESO as prudential support, and a long-term loan facility. These combined facilities are subject to a funded indebtedness debt to equity ratio of no more than 65%.

The Corporation has customary covenants typically associated with long-term debt. As at December 31, 2023 and December 31, 2022, the Corporation was in compliance with all credit agreement covenants and limitations associated with its long-term debt.

22. Financial instruments and risk management:

Fair value disclosure

The carrying values of accounts receivable, unbilled revenue, due to Corporations under common control & to the City of Stratford, accounts payable and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair values of customer deposits approximate their carrying amounts taking into account interest accrued on the outstanding balance. Cash is measured at fair value.

The swap agreements are measured at fair value, which is provided by a third-party, banking institution and is based on market rates at the date of the valuation. The valuation of the interest rate swaps resulted in a cumulative unrealized gain recorded on the statement of financial position at December 31, 2023 of $454,755 (2022 - $784,886).

The fair value of the long-term borrowings is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The carrying amounts and fair values of the Corporation's long-term loans consist of the following:

22. Financial instruments and risk management (continued):

	2023	2022
Carrying amounts:		
Notes payable to shareholder, bearing interest at 7.25% per annum, due on demand	$15,600,000	$15,600,000
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 1.81%, maturing May 31, 2038	9,369,000	9,875,000
Royal Bank revolving term loan, bearing variable interest at 5.39%, plus a stamping fee of 1.51%, interest only payments until December 31, 2024	2,500,000	-
Royal Bank loan, bearing interest at 2.62%, maturing November 25, 2025	443,012	665,476
Total	**$27,912,012**	**$26,140,476**

	2023	2022
Fair values:		
Notes payable to shareholder, bearing interest at 7.25% per annum, due on demand	$11,797,814	$12,556,106
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 1.81%, maturing May 31, 2038	5,502,035	9,581,114
Royal Bank revolving term loan, with a variable interest rate of 5.39%, plus a stamping fee of 1.51% on bankers' acceptances, interest only payments until December 31, 2024	2,332,090	-
Royal Bank loan, bearing interest at 2.62%, maturing November 25, 2025	410,511	609,697
Total	**$20,042,450**	**$22,746,917**

Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed. The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

a) *Credit risk*

The Corporation is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

22. Financial instruments and risk management (continued):

a) *Credit risk (continued)*

The Corporation's credit risk associated with accounts receivable and unbilled revenue is primarily related to electricity bill payments from electricity customers. The Corporation obtains security deposits from certain customers in accordance with direction provided by the OEB and as outlined in the Corporation's conditions of service. As of December 31, 2023, the Corporation held security deposits related to electricity receivables in the amount of $911,071 (2022 - $957,164).

As at December 31, 2023, there were no significant concentrations of credit risk with respect to any one customer. No single customer accounts for revenue in excess of 5% of total distribution revenue. The Corporation earns its revenue from a broad base of approximately 21,000 customers (2022 - 21,000 customers) located throughout its service territory.

The credit risk and mitigation strategies with respect to unbilled revenue are the same as for accounts receivable. The credit risk related to cash is mitigated by the Corporation's treasury policies on assessing and monitoring the credit exposures of counterparties.

Credit risk associated with electricity accounts receivable and unbilled revenue (electricity only) is as follows:

	2023	2022
Not more than 30 days	$ 5,497,458	$ 6,448,968
More than 30 but less than 90 days	589,425	405,840
More than 90 days	103,687	167,531
Less allowance for impairment	(180,369)	(173,017)
Unbilled revenue	6,915,469	4,783,498
	$ 12,925,670	**$ 11,632,820**

As at December 31, 2023, the Corporation's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for impairment was required for these balances.

Reconciliation between the opening and closing allowance for impairment is as follows:

	2023	2022
Balance, beginning of year	$ 173,017	$ 178,684
Provision for impairment	117,179	53,870
Write offs	(117,115)	(72,374)
Recoveries	7,288	12,837
Balance, end of year	**$ 180,369**	**$ 173,017**

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at year end. Unbilled revenue is considered current and no provision for impairment was established as at December 31, 2023 (2022 – nil).

22. Financial instruments and risk management (continued):

(b) Interest rate risk

The Corporation is exposed to fluctuations in interest rates for the valuation of its employee future benefit obligations (note 12). The Corporation is also exposed to short-term interest rate risk on the net of cash position and short-term borrowings under its Revolving Credit Facility and customer deposits. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments and taking action as necessary to maintain an appropriate balance.

As at December 31, 2023, aside from the valuation of its employee future benefit obligations, the Corporation was exposed to interest rate risk predominately from short-term borrowings under its revolving credit facility and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation estimates that a 100 basis point increase in short-term interest rates, with all other variables held constant, would result in an increase of approximately $116,070 (2022 - $61,266) to annual finance costs. A decrease of 100 basis points would result in a reduction in financing costs of $116,070 (2022 – $61,266).

(c) Liquidity risk

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and monitors cash balances daily. The Corporation’s objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

The Corporation has a revolving credit facility available of $10,000,000 with a Canadian chartered bank. As at December 31, 2023, $3,800,000 (2022 - $4,280,000) was drawn on this facility.

As a purchaser of electricity through the Independent Electricity System Operator (“IESO”), the Corporation is required to provide security to minimize the risk of default based on its expected activity in the market. The IESO may draw on this security if the Corporation fails to make payment required by a default notice issue by the IESO. The Corporation has a $3.6 million revolving term facility by way of a letter of guarantee with Royal Bank, of which $3,095,139 (2022 - $3,095,139) has been assigned to secure the prudential support required by the IESO.

The majority of accounts payable, as reported on the statement of financial position, is due within 30 days.
Liquidity risks associated with financial commitments are as follows:

22. Financial instruments and risk management (continued):

Contractual cash flows, including interest, at year end are:

December 31, 2023

	Carrying Amounts	Total	Due within 1 year	Due within 1 to 5 years	Due> 5 years
Revolving credit facility	$ 3,800,000	$ 3,800,000	$ 3,800,000	$ -	$ -
Accounts payable and accrued liabilities	9,367,511	9,367,511	9,367,511	-	-
Due to City of Stratford	611,591	611,591	611,591	-	-
Notes payable to shareholder, bearing interest at 7.25% per annum, due on demand	15,600,000	16,731,000	16,731,000	-	-
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 1.81%, maturing May 31, 2038	9,369,000	12,832,870	958,369	3,731,883	8,142,618
Royal Bank loan, bearing interest at 2.62%, maturing November 25, 2025	443,012	454,673	237,221	217,452	-
Royal Bank revolving term loan, bearing variable interest at 5.39%, plus a stamping fee of 1.51%, interest only payments until December 31, 2024	2,500,000	2,672,500	2,672,500	-	-
	$ 41,691,114	$ 46,470,145	$ 34,378,192	$ 3,949,335	$ 8,142,618

December 31, 2022

	Carrying Amounts	Total	Due within 1 year	Due within 1 to 5 years	Due> 5 years
Revolving credit facility	$ 4,280,000	$ 4,280,000	$ 4,280,000	$ -	$ -
Accounts payable and accrued liabilities	8,658,017	8,658,017	8,658,017	-	-
Due to City of Stratford	630,031	630,031	630,031	-	-
Notes payable to shareholder, bearing interest at 7.25% per annum, due on demand	15,600,000	16,731,000	16,731,000	-	-
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 1.81%, maturing May 31, 2038	9,875,000	12,645,318	828,224	3,308,138	8,508,956
Royal Bank loan, bearing interest at 2.62%, maturing November 25, 2025	665,476	691,894	237,221	454,673	-
	$ 39,708,524	$ 43,636,260	$ 31,364,493	$ 3,762,811	$ 8,508,956

23. Commitments and contingencies:

Operating leases

The Corporation entered into a non-cancellable operating lease for service centre space for a period of five years dated November 15, 2015. The contract is subject to an annual increase based on the Ontario Consumer Price Index. Minimum lease payments required are $1,027 per month for 2023 (2022 - $997 per month).

Connection and cost recovery agreement - St. Mary's transformer station

The Corporation and Hydro One Networks Inc. entered into a twenty-five-year capital cost recovery agreement ("CCRA") in September 2002 relating to Hydro One Networks Inc. building new feeder positions at the existing St. Mary's Transformer Station. Under the terms of the agreement, the Corporation has guaranteed new load growth which, if not met, would require the Corporation to provide a financial contribution toward the capital investment of the transformer station.

The CCRA has been trued-up effective July 5, 2013. Since load growth had fallen below a target amount, a cumulative contribution in the amount of $550,200 has been paid to Hydro One Networks. This amount has been recorded as an intangible asset subject to 15-year amortization over the remaining life of the agreement. The agreement was subject to true up effective on the fifteenth year of the agreement in July 2018 however, this has not been completed by Hydro One Inc. It is possible that the Corporation may owe a further payment as a result of the agreement but an estimate of any amount owing is not possible at December 31, 2023 given the nature of the variables included in the calculation. The need for a contribution will be determined by Hydro One Networks Inc. based on actual new load growth.

Connection and cost recovery agreement-Stratford transformer station ("Festival Hydro MTS1")

The Corporation and Hydro One Networks Inc. entered into a twenty-five-year CCRA in November, 2012, relating to Hydro One Networks Inc. building a new 230kV line to connect Festival Hydro`s MTS1 to Hydro One`s 230kV circuit. Under the terms of the agreement, the Corporation has guaranteed new load growth which, if not met, would require the Corporation to provide a financial contribution toward the capital investment. The CCRA is trued-up (a) following the fifth and tenth anniversaries of the in-service date; and (b) following the fifteenth anniversary of the in-service date if the actual load is 20% higher or lower than the load forecast at the end of the tenth anniversary of the in-service date. The fifth anniversary of the in-service date was in November 2017. The need for a contribution will be determined by Hydro One Networks Inc. based on actual new load growth.

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation’s financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (“MEARIE”). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2023, no assessments had been made.

24. Comparative figures:

Certain comparative figures have been restated to conform to the current year presentation.

Attachment 1 –13

2022 Audited Financial Statements

Financial Statements of

Festival Hydro Inc.

Year ended December 31, 2022

KPMG LLP
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London ON N6A 5P2
Canada
Tel 519 672-4880
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INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Festival Hydro Inc.

Opinion

We have audited the financial statements of Festival Hydro Inc. (the Entity), which comprise:

- the statement of financial position as at December 31, 2022
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditor's Responsibilities for the Audit of the Financial Statements***" section of our auditor's 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 International Financial Reporting Standards (IFRS), 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.

Auditor's 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 auditor's 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 auditor's 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 auditor's 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

London, Canada

April 28, 2023

Festival Hydro Inc.

Statement of Financial Position
December 31, 2022, with comparative information for December 31, 2021

	Notes	2022	2021
Assets			
Accounts receivable	6, 22	$ 8,079,655	$ 8,124,901
Unbilled revenue	22	4,783,498	5,230,771
Inventories	7	177,526	163,443
Prepaid expenses		230,441	357,282
Income tax receivable		511,562	356,057
Due from corporations under common control	20	122,147	332,803
Total current assets		**13,904,829**	**14,565,257**
Non-current assets			
Property, plant and equipment	8	58,854,033	57,113,909
Intangible assets and goodwill	9	1,806,282	1,734,841
Unrealized gain on interest rate swap	22	784,886	-
Total non-current assets		**61,445,201**	**58,848,750**
Total assets		**75,350,030**	**73,414,007**
Regulatory balances	13	7,503,962	4,527,854
Total assets and regulatory balances		**$ 82,853,992**	**$ 77,941,861**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Financial Position

December 31, 2022, with comparative information for December 31, 2021

	Notes	2022	2021
Liabilities and Equity			
Bank indebtedness	5	$ 3,740,695	$ 15,768
Accounts payable and accrued liabilities		8,658,017	9,902,642
Deferred revenue		273,286	194,274
Income tax payable		-	-
Dividend payable	15, 21	248,269	500,556
Current portion of long-term debt	14, 22	16,328,464	16,307,717
Customer deposits	11	1,016,175	1,169,542
Due to the Corporation of the City of Stratford	20	624,251	625,460
Total current liabilities		**30,889,157**	**28,715,959**
Non-current liabilities			
Deferred revenue		2,641,341	2,453,813
Customer deposits	11	980,367	594,311
Deferred tax liabilities	10	2,381,370	1,308,987
Employee future benefits	12	1,009,878	1,361,643
Unrealized loss on interest rate swap	22	-	938,948
Long-term debt	14, 22	9,812,012	10,540,477
Total non-current liabilities		16,824,968	17,198,179
Total liabilities		**47,714,125**	**45,914,138**
Share capital	15	15,568,388	15,568,388
Accumulated other comprehensive loss		(54,479)	(357,737)
Retained earnings		18,525,126	15,085,495
Total equity		**34,039,035**	**30,296,146**
Total liabilities and equity		81,753,160	76,210,284
Regulatory balances	13	1,100,832	1,731,577
Total liabilities, equity and regulatory balances		**82,853,992**	**77,941,861**

Commitments and contingencies (note 23)
Guarantee (note 24)
Subsequent event (Note 25)

The accompanying notes are an integral part of these financial statements.

On behalf of the Board:

Director

Director

Festival Hydro Inc.

Statement of Comprehensive Income

Year ended December 31, 2022, with comparative information for 2021

	Notes	2022	2021
Revenues			
Sale of energy	16	$ 55,589,074	$ 59,559,802
Distribution revenue	16	12,174,085	11,582,698
Other income	17	1,118,521	1,195,884
		68,881,680	**72,338,384**
Cost of power purchased		58,141,145	60,698,856
Operating expenses	18	6,759,045	6,014,814
Depreciation and amortization	8,9	2,505,726	2,412,000
		67,405,916	**69,125,670**
Income from operating activities		**1,475,764**	**3,212,714**
Finance income	19	1,747,174	664,530
Finance costs	19	(1,574,778)	(1,604,249)
Income before income taxes		**1,648,160**	**2,272,995**
Income tax expense	10	1,096,421	917,289
Net income		**551,739**	**1,355,706**
Net movement in regulatory balances:			
Net movement in regulatory balances	13	2,534,470	1,168,069
Income tax	10,13	992,021	590,859
Net income and net movement in regulatory balances		**4,078,230**	**3,114,634**
Other comprehensive income (loss)			
Items that will not be reclassified to profit and loss:			
Remeasurements of employee future benefits	12	303,258	80,606
Tax on remeasurements	10	(80,363)	(21,361)
Net movement in regulatory balances	13	80,363	21,361
Other comprehensive loss		**303,258**	**80,606**
Total comprehensive income		**$ 4,381,488**	**$ 3,195,240**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Changes in Equity

Year ended December 31, 2022, with comparative information for December 31, 2021

	Share capital	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2021	**$15,568,388**	**$12,861,747**	**$ (438,343)**	**$ 27,991,792**
Net income after net movement in regulatory balances	–	3,114,634	–	3,114,634
Other comprehensive loss	–	–	80,606	80,606
Dividends, paid or payable	–	(890,886)	–	(890,886)
Balance at December 31, 2021	**$15,568,388**	**$15,085,495**	**$ (357,737)**	**$ 30,296,146**
Balance at January 1, 2022	**$15,568,388**	**$15,085,495**	**$ (357,737)**	**$ 30,296,146**
Net income after net movement in regulatory balances	–	4,078,230	–	4,078,230
Other comprehensive loss	–	–	303,258	303,258
Dividends, paid or payable	–	(638,599)	–	(638,599)
Balance at December 31, 2022	**$15,568,388**	**$18,525,126**	**$ (54,479)**	**$ 34,039,035**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Cash Flows

Year ended December 31, 2022, with comparative information for December 31, 2021

Cash provided by (used in)	Notes	2022	2021
Operating activities			
Net income after net movement in regulatory balances		$4,078,230	$3,114,634
Adjustments for			
Depreciation - property, plant and equipment	8	2,243,817	2,113,654
Amortization - intangible assets	9	261,909	298,348
Amortization of deferred revenue		(76,869)	(60,633)
Employee future benefits		(48,508)	(50,668)
Net finance costs	19	(172,396)	939,718
Income tax expense	10	1,096,421	917,289
		7,382,604	7,272,342
Changes in non-cash operating working capital			
Accounts receivable		45,246	(1,104,430)
Unbilled revenue		447,273	1,140,450
Inventories		(14,083)	9,169
Prepaid expenses		126,841	32,564
Accounts payable and accrued liabilities		(1,244,625)	1,314,930
Due from related parties		210,656	294,268
Due from the City of Stratford		(1,209)	(6,477)
Dividends declared		(252,287)	385,345
Customer deposits		232,689	269,859
		(449,499)	2,335,678
Regulatory balances	13	(3,526,490)	(1,758,928)
Interest paid	19	(1,574,778)	(1,604,248)
Interest received		23,340	18,445
Income tax paid, net of refund		(5,476)	(888,101)
Net cash from operating activities		**1,849,701**	**5,375,188**
Investing activities			
Purchase of property, plant and equipment	8	(3,983,941)	(3,780,502)
Purchase of intangible assets	9	(333,350)	(77,945)
Net cash used in investing activities		(4,317,291)	(3,858,447)
Financing activities			
Contributions received from customers, net of repayments		341,267	479,666
Dividends	15	(890,886)	(505,541)
Proceeds from long-term debt		-	900,000
Repayment of long-term debt		(707,718)	(1,429,445)
Net cash used in financing activities		(1,257,337)	(555,320)
Decrease in bank indebtedness during the year		(3,724,927)	961,421
Bank indebtedness, beginning of the year		(15,768)	(977,189)
Bank indebtedness, end of the year		**$ (3,740,695)**	**$ (15,768)**

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

Festival Hydro Inc. (the "Corporation") is a wholly owned subsidiary of the City of Stratford. The Corporation was incorporated on July 11, 2000 under the Business Corporations Act (Ontario) pursuant to Section 142 of the Electricity Act Laws of the Province of Ontario, Canada. The address of the Corporation's registered office is 187 Erie Street, Stratford, Ontario, Canada.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the City of Stratford and the towns of Brussels, Dashwood, Hensall, Seaforth, St. Marys and Zurich, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the Ontario Energy Board and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2022.

2. Basis of preparation:

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). These financial statements were approved by the Board of Directors on April 27, 2023.

(b) Basis of measurement

The financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

(d) Use of estimates and judgements

Information about judgements made in applying accounting policies that have an effect on the amounts recognized in the financial statements is included in the following notes:

Note 3(l)	Determination of the performance obligation for contribution and the related amortization period
Note 3(m)	Whether an arrangement contains a lease
Note 6	Estimate for impairment for uncollected amounts, based on the lifetime expected credit losses
Note 8	Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment.
Note 9	Intangible assets: useful lives and goodwill impairment testing.
Note 12	Measurement of the defined benefit obligation – actuarial assumptions
Note 23	Recognition and measurement of commitments and contingencies.

2. Basis of preparation (continued)

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board, under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Corporation, which may include, amongst other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill certain classes of customers for the debt retirement charges. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation (“OEFC”) once each year.

(f) Rate setting

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder’s equity required to support the Corporation’s business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each class. The COS application is reviewed by the OEB and interveners on record. Rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years, the Corporation has chosen to file a Price Cap Incentive Rate Mechanism (“IRM”) application. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“GDP IPI-FDD”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

On May 27, 2014, the Corporation filed its 2015 Cost of Service application. The OEB issued its final Decision and Order dated June 5, 2015. The decision allows for a total service revenue requirement of $11,210,828 based on a total rate base of $61,778,759. The deemed debt portion of the rate base (60%) at $27,067,256 earns a weighted average rate of 4.05%. The deemed equity portion of the rate base (40%) at $24,711,504 earns a deemed return on equity of 9.30%. The rates were effective May 1, 2015 with an implementation date of June 1, 2015.

2. Basis of preparation (continued)

(f) Rate setting (continued)

Distribution revenue (continued)

Festival filed its 2021 IRM application for distribution rates and was approved new rates by the OEB effective January 1, 2021. The Corporation's approved adjustment to distribution rates was 1.90%, as a result of an OEB approved inflation factor of 2.20%, less a stretch factor of 0.30% determined by the relative efficiency of the Corporation. The application included the approval of rate riders for the disposition of certain deferral and variance balances.

Festival filed its 2022 IRM application for distribution rates and was approved new rates by the OEB effective January 1, 2022. The Corporation's approved adjustment to distribution rates was 3.00%, as a result of an OEB approved inflation factor of 3.30%, less a stretch factor of 0.30% determined by the relative efficiency of the Corporation. The application included the approval of rate riders for the disposition of certain deferral and variance balances.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity and the global adjustment. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently for both years presented in these financial statements in accordance with IFRS.

(a) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income (“OCI”). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. Significant accounting policies (continue):

(a) Regulatory balances (continued)

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts. On the statement of cash flows, cash and cash equivalents includes bank overdrafts (revolving credit facility) that are repayable on demand and form an integral part of the Corporation’s cash management.

(c) Financial instruments

All financial assets are classified as loans and receivables, except for marketable securities which are classified as available for sale and derivatives which are measured as fair value through profit and loss. All financial liabilities are classified as other financial liabilities. These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs.

Loans and receivables and other financial liabilities are subsequently measured at amortized cost using the effective interest method less any impairment for the financial assets.

Available for sale financial assets are subsequently measured at fair value, within the changes therein recognized in other comprehensive income until the assets are sold. Upon sale of an available for sale asset, the Corporation has elected to record the accumulated unrealized change in value of the asset as a transfer through other comprehensive income into profit and loss.

The Corporation holds derivative financial instruments to manage its interest rate risk exposures. Derivatives are initially measured at fair value; any directly attributable transaction costs are recognized in profit or loss as incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein, are recognized in the statement of comprehensive income. Hedge accounting has not been used in the preparation of these financial statements.

(d) Inventories

Inventories are stated at lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis, net of a provision for obsolescence, as applicable. The Corporation classifies all major construction related component of its electricity distribution infrastructure to property, plant and equipment.

(e) Property, plant and equipment (“PP&E”)

Items of property, plant and equipment used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, or, where the item is transferred from customers, its fair value, less accumulated depreciation and accumulated impairment losses. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

3. Significant accounting policies (continued):

(e) Property, plant and equipment ("PP&E")

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour and any other costs directly attributable to bringing the asset to a working condition for its intended use. Borrowing costs on qualifying assets are capitalized as part of the cost of the asset and are based on the Corporation's cost of borrowing. For construction projects of less than one year in length, borrowing costs are not capitalized unless specific identifiable loans are acquired for the express purpose of financing a specific construction activity.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing part of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. The carrying amount of the replaced part is derecognized.

The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred. Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not amortized until the project is complete and in service.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives. Depreciation methods, useful lives and residual values are reviewed at each reporting date and adjusted if appropriate. The estimated useful lives for the current and comparative years are as follows:

Buildings	10 to 60 years
Distribution substation equipment	30 to 60 years
Distribution system equipment	30 to 60 years
Transformers	35 to 40 years
Meters	15 to 40 years
Other capital assets	4 to 20 years

Other capital assets include vehicles, office and computer equipment.

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized within other income in the statement of comprehensive income.

3. Significant accounting policies (continued):

(f) Intangible assets

Intangible assets include goodwill, computer software and capital contributions paid under capital cost recovery agreements ("CCRAs").

(i) Goodwill

Goodwill represents the excess of cost over fair value of net assets which arose upon amalgamation of the former electrical distribution entities. Goodwill is measured at cost less accumulated impairment losses.

(ii) Computer software

Computer software acquired prior to January 1, 2014, is measured at deemed cost less accumulated depreciation. All other software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

(iii) Capital contributions paid under capital cost recovery agreements

Capital contributions paid under CCRAs are measured at cost less accumulated amortization and accumulated impairment losses.

(iv) Amortization

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. The estimated useful lives for the current and comparative years are:

Computer software	5 years
CCRAs	15 to 25 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted if appropriate.

(g) Impairment

(i) Financial assets measured at amortized cost

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

3. Significant accounting policies (continued):

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than regulatory assets, inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill, the recoverable amount is estimated as at December 31 of each year.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The Corporation has determined that it has one cash generating unit. The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to cash-generating units that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Employee benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“Fund”). The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

3. Significant accounting policies (continued):

(i) Pension plan (continued)

OMERS is a defined benefit plan, however, as the plan assets and pension obligations are not segregated in separate accounts for each member entity, sufficient information is not available to enable the Corporation to directly account for the plan. As such, the plan has been accounted for as a defined contribution plan. The contribution payable is recognized as an employee benefit expense in the statement of comprehensive income in the period in which the service was rendered by the employee, since it is not practicable to determine the Corporation's portion of person obligations of the fair value of plan assets.

(ii) Employee future benefits, other than pension

The Corporation has an unfunded benefit plan providing post-employment benefits (other than pension) to its employees. The Corporation provides its retired employees (20 years service; less than age 65) with life insurance and medical benefits beyond those provided by government sponsored plans. Life insurance is provided for current retirees including those over age 65.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses, are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(j) Deferred revenue and assets transferred from customers

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded under current liabilities as customer deposits. Once the distribution system asset is completed or modified, as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction. The contributions in aid of construction account, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is reported as deferred revenue, and is amortized to other income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(k) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts, calculated using OEB prescribed interest rates, and owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability. Annually, accrued interest is applied directly to the customers' accounts.

3. Significant accounting policies (continued):

(k) Customer deposits (continued)

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when the Corporation no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

(l) Revenue Recognition

(i) Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

(ii) Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

3. Significant accounting policies (continued):

(l) Revenue Recognition (continued)

(ii) Other revenue

Revenue earned from the provision of services is recognized as the service is rendered. Government grants and the related performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(m) Leased assets

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

3. Significant accounting policies (continued):

(n) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on customer deposits, the demand notes payable, revolving credit facility and long-term borrowings.

Changes in the fair value of interest rate swap agreements are recorded either in finance income, or costs, depending on whether an unrealized gain or loss is required.

(o) Income taxes

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to other comprehensive income or items recognized directly in equity, in which case, it is recognized in accumulated comprehensive income or retained earnings, respectively.

Current tax is the tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit or debt balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of comprehensive income.

3. Significant accounting policies (continued):

(o) Income taxes (continued)

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of comprehensive income.

4. Standards issued but not yet adopted:

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. These standards or amendments relate to the measurement and disclosure of financial assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

i. Classification of Liabilities as Current or Non-current (Amendments to IAS 1)
ii. Definition of Accounting Estimates (Amendments to IAS 8)
iii. Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)

i. Classification of Liabilities as Current or Non-current (Amendments to IAS 1):

On January 23, 2020, the IASB issued amendments to IAS 1 Presentation of Financial Statements, to clarify the classification of liabilities as current or non-current. On July 15, 2020 the IASB issued an amendment to defer the effective date by one year. The amendments are effective for annual periods beginning on or after January 1, 2024. Early adoption is permitted.

For the purposes of non-current classification, the amendments removed the requirement for a right to defer settlement or roll over of a liability for at least twelve months to be unconditional. Instead, such a right must have substance and exist at the end of the reporting period. The amendments also clarify how a company classifies a liability that includes a counterparty conversion option.

The amendments state that settlement of a liability includes transferring a company's own equity instruments to the counterparty, and when classifying liabilities as current or non-current, a company can ignore only those conversion options that are recognized as equity.

The Corporation intends to adopt this standard in its financial statements for the annual period beginning January 1, 2023. The extent of the impact of adoption of the standard has not yet been determined

ii. Definition of Accounting Estimates (Amendments to IAS 8):

On February 12, 2021, the IASB issued Definition of Accounting Estimates (Amendments to IAS 8). The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

4. Standards issued but not yet adopted (continued):

The amendments introduce a new definition for accounting estimates, clarifying that they are monetary amounts in the financial statements that are subject to measurement uncertainty. The amendments also clarify the relationship between accounting policies and accounting estimates by specifying that a company develops an accounting estimate to achieve the objective set out by an accounting policy.

The Company intends to adopt this standard in its financial statements for the annual period beginning January 1, 2023. The extent of the impact of adoption of the standard has not yet been determined.

iii. Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2):

On February 12, 2021, the IASB issued Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2 Making Materiality Judgements). The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

The amendments help companies provide useful accounting policy disclosures. The key amendments include:

– requiring companies to disclose their material accounting policies rather than their significant accounting policies;

– clarifying that accounting policies related to immaterial transactions, other events or conditions are themselves immaterial and as such need not be disclosed; and

– clarifying that not all accounting policies that relate to material transactions, other events or conditions are themselves material to a company's financial statements.

The Company intends to adopt this standard in its financial statements for the annual period beginning January 1, 2023. The Company does not expect this standard to have a material impact on the financial statements.

5. Bank indebtedness:

	2022	2021
Cash	$ 660	$ 1,660
Revolving credit facility	(3,741,355)	(17,428)
Bank indebtedness	**$ (3,740,695)**	**$ (15,768)**

6. Accounts receivable:

	2022	2021
Energy, water and sewer	$ 6,523,810	$ 6,223,521
Other	1,555,845	1,901,380
Total	**$ 8,079,655**	**$ 8,124,901**

Included in accounts receivable is $1,230,333 (2021 - $1,193,417) of customer receivables for water consumption and sewer ("water & sewer") that the Corporation bills and collects on behalf of the City of Stratford and the Town of St. Marys. As the Corporation does not assume liability for collection of these amounts, any amount related to City of Stratford and Town of St. Marys water & sewer charges that are determined to be uncollectible are charged to the City of Stratford and Town of St. Marys, respectively. At year end, there is nil (2021 - nil) included in the provision for impairment for uncollectable amounts relating to water and sewer.

7. Inventories:

The amount of inventories consumed by the Corporation and recognized as an expense during 2022 was $149,137 (2021 - $166,873). During 2022, an amount of nil (2021 – nil) was recorded as an expense for the write-down of obsolete or damaged inventory to net realizable value.

8. Property, plant and equipment:

a) Cost or deemed cost

	Land and buildings	Distribution & substation equipment	Other distribution system equipment	Transformer station	Total
Balance at January 1, 2021	$2,663,162	$47,579,167	$2,810,734	$14,049,010	$67,102,073
Additions	477,555	2,698,194	326,676	143,417	3,645,842
Transfers	-	-	134,660	-	134,660
Disposals/retirements	(6,795)	(230,606)	(155,736)	-	(393,137)
Balance at December 31, 2021	**$3,133,922**	**$ 50,046,755**	**$ 3,116,334**	**$ 14,192,427**	**$ 70,489,438**
Balance at January 1, 2022	$3,133,922	$50,046,755	$3,116,334	$14,192,427	$70,489,438
Additions	357,228	3,022,647	281,971	86,263	$3,748,109
Transfers	-	-	235,832	-	$235,832
Disposals/retirements	(27,578)	(297,300)	(375,808)	-	($700,686)
Balance at December 31, 2022	**$3,463,572**	**$52,772,102**	**$3,258,329**	**$14,278,690**	**$73,772,693**

b) Accumulated depreciation

	Land and buildings	Distribution & substation equipment	Other distribution system equipment	Transformer station	Total
Balance at January 1, 2021	$ 337,380	$ 7,977,726	$ 1,119,839	$ 2,220,066	$ 11,655,011
Depreciation	96,716	1,413,877	268,888	334,173	2,113,654
Disposals/retirements	(6,795)	(230,605)	(155,736)	-	(393,136)
Balance at December 31, 2021	$ 427,301	$ 9,160,998	$ 1,232,991	$ 2,554,239	$ 13,375,529
Balance at January 1, 2022	$427,301	$9,160,998	$1,232,991	$2,554,239	$13,375,529
Depreciation	120,660	1,491,865	285,635	345,657	$2,243,817
Disposals/retirements	(27,578)	(297,300)	(375,808)	-	($700,686)
Balance at December 31, 2022	$520,383	$10,355,563	$1,142,818	$2,899,896	$14,918,660

c) Carrying amounts

	Land and buildings	Distribution & substation equipment	Other distribution system equipment	Transformer station	Total
December 31, 2021	$2,706,621	$40,885,757	$1,883,343	$11,638,188	$57,113,909
December 31, 2022	$2,943,189	$42,416,539	$2,115,511	$11,378,794	$58,854,033

d) Borrowing costs

During the year, no borrowing costs (2021 – nil) were capitalized as part of the cost of property, plant and equipment.

9. Intangible assets and goodwill:

a) Cost or deemed cost

	Goodwill	Computer software	Land Rights	CCRA's	Total
Balance at January 1, 2021	$ 515,359	$ 1,593,915	$ 3,150	$ 966,935	$ 3,079,359
Additions	-	77,945	-	-	77,945
Disposals	-	(252,888)	-	-	(252,888)
Balance at December 31, 2021	**$ 515,359**	**$ 1,418,972**	**$ 3,150**	**$ 966,935**	**$ 2,904,416**
Balance at January 1, 2022	$515,359	$ 1,418,972	$ 3,150	$ 966,935	$ 2,904,416
Additions	-	111,889	-	-	111,889
Work in Progress	-	221,461	-	-	221,461
Disposals	-	(312,506)	-	-	(312,506)
Balance at December 31, 2022	**$ 515,359**	**$ 1,439,816**	**$ 3,150**	**$ 966,935**	**$ 2,925,260**

b) Accumulated amortization

	Goodwill	Computer software	Land Rights	CCRA's	Total
Balance at January 1, 2021	**$ -**	**$ 750,096**	**$ -**	**$ 374,019**	**$ 1,124,115**
Amortization	**-**	243,875	**-**	54,473	298,348
Disposals	**-**	(252,888)	**-**	-	(252,888)
Balance at December 31, 2021	$ -	**$ 741,083**	$ -	**$ 428,492**	**$ 1,169,575**
Balance at January 1, 2022	$ -	$ 741,083	$ -	$ 428,492	$ 1,169,575
Amortization	-	207,436	-	54,473	261,909
Disposals	-	(312,506)	-	-	(312,506)
Balance at December 31, 2022	$ -	**$ 636,013**	$ -	**$ 428,492**	**$ 1,118,978**

c) Carrying amounts

	Goodwill	Computer software	Land Rights	CCRA's	Total
December 31, 2021	$ 515,359	$ 677,889	$ 3,150	$ 538,443	$ 1,734,841
December 31, 2022	$ 515,359	$ 803,803	$ 3,150	$ 483,970	$ 1,806,282

d) Goodwill impairment

Management has determined that the Corporation's rate regulated operations are one cash generating unit. Therefore, the goodwill was allocated to the Corporation as a whole. The annual impairment test is based on the Corporation's value in use. Value in use was determined by discounting the future cash flows of the Corporation and was based on the following key assumptions:

9. Intangible assets and goodwill:

d) Goodwill impairment (continued)

A detailed valuation of the Corporation was undertaken during 2022 based on financial results of the Corporation as at December 31, 2022. Cash flows were projected based on actual operating results and the cost of capital and rate of return as approved in the 2015 Cost of Service application. A discounted cash flow model was utilized based on free cash flows for 20 years, followed by a terminal value calculated based on a steady-state cash flow, with the terminal value within range of market-based terminal multiples. The recoverable amount of the Corporation was determined to be greater than the carrying value of goodwill and no impairment was recorded as at December 31, 2022 or December 31, 2021.

10. Income taxes:

	2022	**2021**
Income tax expense		
Current tax expense:		
Current year	$ 160,945	$ 322,507
Prior year	(56,545)	3,923
Total current tax expense	104,400	326,430
Deferred tax expense:		
Change in recognized deductible temporary differences	992,021	590,859
Total current and deferred income tax in profit or loss, before movement of regulatory balance	1,096,421	917,289
Other comprehensive income:		
Employee future benefits	80,363	(21,361)
Total current and deferred tax, before movement in regulatory balances	1,176,784	938,650
Net movement in regulatory balances	(1,072,384)	(612,220)
Income tax expense recognized in statement of comprehensive Income	**$104,400**	**$326,430**

Reconciliation of effective tax rate

	2022	**2021**
Income before taxes	$4,486,834	$3,538,670
Canada and Ontario statutory income tax rates	26.5%	26.5%
Expected tax provision on income tax at statutory rates	1,189,011	937,748
Increase (decrease) in income tax resulting from:		
Permanent differences	2,212	1,420
Recognized deductible temporary difference due from customers	(1,072,384)	(612,220)
Other	(14,439)	(518)
Income tax expense	**$ 104,400**	**$ 326,430**

10. Income taxes (continued):

	2022	2021
Deferred tax assets (liabilities):		
Property, plant, equipment and intangible assets	($2,488,634)	($1,968,063)
Employee future benefits	267,618	360,835
Other	(160,354)	298,241
	($2,381,370)	**($1,308,987)**

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers as well as construction deposits. These customer deposits bear interest at the OEB's prescribed interest rate, which is the Bank of Canada's prime business rate less 2%.

Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service. Due to the demand nature of these deposits, they are classified as current liabilities.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to deferred revenue.

Customer deposits comprise:

	2022	2021
Electricity deposits	$ 957,164	$1,061,051
Construction deposits	1,039,378	702,802
Total customer deposits	**$1,996,542**	**$1,763,853**
Consisting of:		
Short-term	$ 1,016,175	$ 1,169,542
Long-term	980,367	594,311

12. Employee future benefits:

(a) Employee future benefits, other than pension

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Corporation has reflected its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these financial statements. The accrued benefit liability and the corresponding expense were based on results and assumptions determined by actuarial valuation as at December 31, 2022.

12. Employee future benefits (continued):

Changes in the present value of the defined benefit unfunded obligation and the accrued benefit liability:

	2022	2021
Defined benefit obligation, beginning of year	$ 1,361,643	$ 1,492,917
Included in profit or loss:		
Current service cost	36,217	39,189
Interest cost	38,994	37,165
	75,211	76,354
Included in OCI:		
Actuarial (gains) losses arising from changes in financial assumptions	(303,258)	(80,606)
Benefits paid during the year	(123,718)	(127,022)
Defined benefit obligation, end of year	**$1,009,878**	**$1,361,643**

The significant actuarial assumptions used in the valuation are as follows:

	2022	2021
Discount rate	5.05%	3.00%
Rate of compensation increase	3.30%	2.50%
Initial health care cost trend rate	4.70%	4.70%
Initial dental cost trend rate	4.90%	4.90%
Year that rate reaches the rate it is assumed to be	2040	2040
Cost trend rate declines to	4.00%	4.00%

Significant actuarial assumptions for benefit obligation measurement purposes are the discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes in the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely these changes in assumptions would occur in isolation from each other. The approximate effect on the accrued benefit obligation of the entire plan and the estimated net benefit expense of the entire plan if the health care trend rate assumption was increased or decreased by 1%, and all other assumptions were held constant, is as follows:

	2022	2021
Benefit Obligation, end of year	$1,009,878	$1,361,644
1% increase in health care trend rate	26,900	50,156
1% decrease in health care trend rate	(24,300)	(44,744)
1% increase in discount rate	(96,500)	(167,544)
1% decrease in discount rate	119,000	215,456

(b) Pension plan

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System. The plan is a multi-employer, contributory defined benefit pension plan. In 2022, the Corporation made employer contributions of $365,116 to OMERS (2021 - $353,752). The Corporation's net benefit expense has been allocated as follows:

- $138,744 (2021 - $134,426) capitalized as part of PP&E
- $186,209 (2021 - $180,413) charged to operating expenses
- $40,163 (2021 - $38,913) charged to CDM and billable work

12. Employee future benefits (continued):

(b) Pension plan (continued)

As at December 31, 2022, OMERS states that their plan was 95% funded (2021 – 97%). OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. The Corporation's contributions represent less than 1% of the total annual contributions to the OMERS plan.

13. Regulatory assets and liabilities:

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

In the tables below, the "Additions" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts collected through rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of reclassification between the regulatory debit and credit balances. For the years ended December 31, 2022 and 2021, the Corporation did not record any impairments related to regulatory debit balances.

	January 1, 2022	Additions	Recovery/ reversal	Other Movements	December 31, 2022	Notes
Regulatory deferral account debit balances						
Settlement (Group 1) variances	$ 2,939,939	$ 386,141	$ (313,926)	$ 2,075,470	$ 5,087,624	(1)
Stranded meters	2,292	21	-	-	2,313	(2)
LRAM	268,628	(244,237)	256	-	24,646	(1)
Deferred Taxes	1,308,987	1,072,383	-	-	2,381,370	(4)
Rate application costs	8,008	-	-	-	8,008	(3)
	$ 4,527,854	**$1,214,308**	**$ (313,670)**	**$ 2,075,470**	**$ 7,503,962**	

	January 1, 2021	Additions	Recovery/ reversal	Other Movements	December 31, 2021	Notes
Regulatory deferral account debit balances						
Settlement (Group 1) variances	$ 1,605,348	$ 1,538,071	$ (203,135)	$ (345)	$ 2,939,939	(1)
Stranded meters	2,286	6	-	-	2,292	(2)
LRAM	494,049	(219,691)	(5,730)	-	268,628	(1)
Deferred Taxes	696,766	612,221	-	-	1,308,987	(4)
Rate application costs	8,008	-	-	-	8,008	(3)
	$ 2,806,457	**$1,930,607**	**$ (208,865)**	**$(345)**	**$ 4,527,854**	

13. Regulatory assets and liabilities (continued):

	January 1, 2022	Additions	Recovery/ reversal	Other Movements	December 31, 2022	Notes
Regulatory deferral account credit balances						
Settlement (Group 1) variances	$ (1,286,576)	2,500,939	$ 313,670	$ (2,075,470)	(547,437)	(1)
IFRS transition adjustments	(10,783)	-	-	-	(10,783)	(5)
PILS	(434,218)	(108,394)	-	-	(542,612)	
	$ (1,731,577)	**$ 2,392,545**	**$ 313,670**	**$ (2,075,470)**	**$ (1,100,832)**	

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	January 1, 2021	Additions	Recovery/ reversal	Other Movements	December 31, 2021	Notes
Regulatory deferral account credit balances						
Settlement (Group 1) variances	$ (1,507,500)	11,714	$ 208,865	$ 345	(1,286,576)	(1)
IFRS transition adjustments	(10,783)	-	-	-	(10,783)	(5)
PILS	(272,186)	(162,032)	-	-	(434,218)	
	$ (1,790,469)	**$ (150,318)**	**$ 208,865**	**$ 345**	**$ (1,731,577)**	

1) The changes in settlement (Group 1) and LRAM balances outstanding from December 31, 2021 were approved for disposition as part of the 2022 IRM application with rates effective January 1, 2022 to be collected over a 12-month period.

2) As part of the 2015 COS application, the OEB approved the disposition of stranded meters through a rate rider effective May 1, 2015 (implemented June 1, 2015) with recovery over a 7-month period ending December 31, 2015. Since the residual balance is not material, it will remain in place until the next COS application.

3) The 2015 COS rate application costs were approved for recovery by the OEB and have been amortized over a forty-three-month period ending December 31, 2019.

4) Disposition is not requested for the deferred tax balance as it is being reversed through timing differences in the recognition of deferred tax assets. No carrying charges are calculated on this balance.

5) As part of the 2015 COS application, the OEB approved the disposition of the account 1575/76 IFRS transition account balance used to record the difference arising on adoption of new asset useful lives and overhead rates and write off of end-of-life assets. These account balances were included as a rate rider effective May 1, 2015 (implemented June 1, 2015) and were recovered over a 7-month period ended December 31, 2015. Since the residual balance is not material, it will remain in place until the next COS application.

Carrying charges are applied to all regulatory account balances at the OEB prescribed interest rates, with the exception of the deferred tax assets on which no carrying charges are applied.

As part of the Corporation's 2022 IRM application, the change in debit and credit balance settlement (Group 1) variance accounts occurring during fiscal 2021 were approved as part of 2022 distribution rates for recovery over a 12-month period commencing January 1, 2022. As such, the risk associated with the recovery of variance accounts is limited to the incremental value of non-settlement variances arising since 2021.

14. Long-term debt:

Long-term debt consists of the following:

	2022	2021
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 0.42%, payable in monthly principal instalments of approximately $35,000 plus interest, increasing by $1,000 yearly until maturity on May 31, 2038, secured by a general security agreement.	9,875,000	10,366,000
Royal Bank loan, bearing interest at 2.62%, payable in monthly principal instalments of $19,768, maturing November 25, 2025, secured by a general security agreement.	665,476	882,194
Notes payable to shareholder, bearing interest at 7.25% per annum, with interest payments only, due on demand, unsecured.	15,600,000	15,600,000
	26,140,476	**26,848,194**
Less: current portion	16,328,464	16,307,717
Long-term debt	**$9,812,012**	**$10,540,477**

Interest rate swaps

The Corporation entered into an interest rate swap agreement on a notional principal of $14,000,000 effective May 31, 2013, which matures May 31, 2038. The swap is a receive-variable, pay-fixed swap with the Royal Bank. This agreement has effectively converted variable interest rates to an effective fixed interest rate of 2.93% plus stamping fee of 0.42% on the Royal Bank revolving term loan. The stamping fee is subject to change every 10 years, with the first maturity being May 31, 2023.

Additionally, the Corporation entered into an interest rate swap agreement on a notional principal of $5,000,000. The Corporation has not yet made any draws on this available credit and is not required to do so until the effective date of December 31, 2024. This agreement has effectively converted variable interest rates to an effective fixed interest rate of 2.51% plus stamping fee of 0.42% on the Royal Bank revolving term loan.

The Corporation has determined these swaps do not meet the standard to apply hedge accounting. Since the standard is not met, the interest rate swap contracts have been recorded at their fair value at December 31, 2022 with the combined unrealized gain for the year of $1,723,834 (2021 – $646,085) recorded as finance cost in the statement of comprehensive income.

14. Long-term debt continued:

Reconciliation of movements of liabilities to cash flows arising from financing activities:

	Current and long-term debt	Dividends payable	Retained earnings	Total (financing cash flows)
Balance at January 1, 2022	$ 26,848,194	$ 500,556	$ 15,085,495	
Dividends paid	-	(500,556)	(390,330)	$ (890,886)
Proceeds from long-term debt	-	-	-	-
Repayments of long-term debt	(707,718)	-	-	(707,718)
Total changes from financing cash flows	**$ (707,718)**	**$ (500,556)**	**$ (390,330)**	**$ (1,598,604)**
Dividend declared but not paid	-	248,269	(248,269)	-
Net income after net movements in regulatory balances	-	-	4,078,230	-
Balance at December 31, 2022	$ 26,140,476	$ 248,269	$ 18,525,126	$ -

15. Share capital:

	2022	**2021**
Authorized:		
Unlimited Class A special shares, non-cumulative, 5.0%		
Unlimited Class B special shares		
Unlimited Common shares		
Issued:		
6,100 Class A special shares	$ 6,100,000	$ 6,100,000
6,995 Common shares	9,468,388	9,468,388
	$ 15,568,388	**$15,568,388**

Dividends paid on the 6,100 class A special shares during the year totalled $152,500 (2021 - $152,500). Dividends paid on the 6,995 common shares during the year totalled $486,099 (2021 - $738,386). A common share dividend was declared on December 15, 2022 and is payable on all common shares on record at December 31, 2022, with the dividend to be paid in 2023. The dividend amount payable at December 31, 2022 is $248,269 (2021 - $500,556).

16. Revenue from Contracts with Customer:

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. Sources of revenue are as documented in the table below.

	2022 Sale of Energy	2022 Distribution Revenue	2021 Sale of Energy	2021 Distribution Revenue
Residential	$ 17,226,469	$ 6,928,900	$ 16,035,245	$ 6,695,809
Commercial	35,806,876	4,757,459	39,685,538	4,553,668
Large Users	2,762,863	314,993	2,653,924	321,241
Other	(207,133)	172,733	1,185,095	11,980
	$ 55,589,074	**$ 12,174,085**	**$ 59,559,802**	**$ 11,582,698**

17. Other income:

	2022	2021
Collection, late payment and other service charges	$ 124,331	$ 187,699
Pole attachment and other rental income	108,836	128,767
Miscellaneous	853,362	852,693
Solar generation	31,992	26,725
	$ 1,118,521	**$ 1,195,884**

Collection, late payment and other service charges are based on service charge rates and retailer rates as approved by the OEB. Pole attachment and other rentals consist primarily of pole attachment charges and charges for office and service centre space.

Miscellaneous includes revenues from City of Stratford and Town of St. Marys water and sewage billing services, street lighting services, management fees charged to Festival Hydro Services Inc. and other revenue sources.

18. Operating expenses:

	2022	2021
Salaries and benefits	$ 3,329,138	$ 3,003,417
External services	1,924,106	1,664,018
Materials and supplies	584,647	624,585
Other support costs	921,154	722,794
	$ 6,759,045	**$ 6,014,814**

19. Finance income and costs:

	2022	2021
Interest income on loan to corporation under common control	$ 10,862	$ 13,587
Interest on bank account	12,036	2,991
Interest on written off trade receivables	442	1,867
Unrealized gain on interest rate swap	1,723,834	646,085
Finance income	**$ 1,747,174**	**$ 664,530**
Interest expense on demand notes payable	$1,131,000	$1,131,000
Interest expense on long-term debt	338,185	378,136
Interest on revolving credit facility	84,552	24,449
Interest expense on deposits	21,041	6,207
Other interest expense	-	64,457
Finance costs	**$ 1,574,778**	**$ 1,604,249**
Net finance income (costs)	**$ 172,396**	**$ (939,719)**

Other interest expenses of $64,457 in 2021 are related to accrued interest and discharge fees for the early payment of the Infrastructure Ontario Projects Corporation (OIPC) loans with a combined principal payout of $842,668.

20. Related party transactions:

a) *Parent and ultimate controlling party*

The parent and sole shareholder of the Corporation is the Corporation of the City of Stratford (the “City”). The City of Stratford produces financial statements that are available for public use.

b) *Key management personnel*

The key management personnel of the Corporation has been defined as members of its Board of Directors and executive management team members. Total compensation of key management in 2022 was $833,946 (2021 - $662,748).

20. Related party transactions (continued):

(b) Transactions with the Corporation of the City of Stratford

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts, with the parent, the City of Stratford, for the years ended December 31:

	2022	2021
Revenues:		
Energy sales	$ 1,475,873	$ 1,612,278
Water and sewer administration fee	499,716	494,093
Street lighting services	18,760	34,878
Service centre space rental	33,477	27,638
Total revenues	$ 2,027,826	$ 2,168,887
Expenses:		
Interest on demand notes payable	$ 1,131,000	$ 1,131,000
Property taxes	121,157	118,062
Tree trimming	54,494	78,073
Total expenses	$ 1,306,651	$ 1,327,135

	December 31, 2022	December 31, 2021
Receivable balances:		
Accounts receivable	$ 371,073	$ 370,838
Payable balances:		
Accounts payable and accrued charges	$ 995,324	$ 996,298
Demand notes payable	15,600,000	15,600,000
Dividends payable	248,269	500,556
Total payables	$16,843,593	$17,096,854

The net amount owing to the Corporation of the City of Stratford for accounts receivable, accounts payable and accrued charges is $624,251 (2021 - $625,460).

Dividends paid or payable	$ 638,599	$ 890,886

20. Related party transactions (continued):

(c) Transactions with corporations under common control of the parent

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts, with Festival Hydro Services Inc., a wholly-owned subsidiary of the City of Stratford, for the years ended December 31:

	2022	2021
Revenues:		
Operational services	$ 33,397	$ 40,872
Management fee	64,851	57,518
Office and fibre room rentals	1,470	1,225
Joint pole rentals	55,308	71,311
Interest earned	10,862	13,712
Energy sales	28,689	25,687
Water billing and collection services	75,120	73,410
Total revenues	$269,697	$283,735
Expenses:		
Fiber and WIFI services	$154,148	$154,148
Information technology and management services	273,165	128,117
Total expenses	$427,313	$282,265

Receivable balance:		
	December 31, 2022	**December 31, 2021**
Due from corporations under common control	$122,147	$332,803

21. Capital management:

The Corporation's main objectives when managing capital is to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents or committed credit facilities) to meet the needs of the business;
- ensure compliance with covenants related to its credit facilities; and
- prudent management of its capital structure with regard to recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios. The Corporation manages capital by preparing short-term and long-term cash flow forecasts, statements of financial position and comprehensive statements of income. In addition, the Corporation accesses its revolving credit facility to fund net periodic net cash outflows and to maintain available liquidity.

There have been no changes in the Corporation's approach to capital management during the year. As at December 31, 2022, the Corporation's definition of capital included borrowings under its revolving credit facility, long-term debt and obligations including the current portion thereof, and equity, and had remained unchanged from the definition as at December 31, 2021. As at December 31, 2022, equity amounted to $34,039,035 (2021 - $30,296,146), borrowings in the form of demand notes payable and long-term debt, including the current portion thereof, amounted to $26,140,476 (2021 - $26,848,194) and the revolving credit facility amounted to $3,720,132 (2021 - $17,428).

21. Capital management (continued):

The OEB regulates the amount of deemed interest on debt and rate of return that may be recovered by the Corporation, through its electricity distribution rates, in respect of its regulated electricity distribution business. The OEB permits such recoveries on the basis of a deemed capital structure represented by 60% debt and 40% equity. The actual capital structure and finance costs for the Corporation may differ from the OEB deemed structure.

The Corporation is subject to debt agreements that contain various covenants. The Corporation's credit agreement with Royal Bank provides a revolving demand facility, letter of guarantee which is posted with the IESO as prudential support, and a long-term loan facility. These combined facilities are subject to a funded indebtedness debt to equity ratio of no more than 65%.

The Corporation has customary covenants typically associated with long-term debt. As at December 31, 2022 and December 31, 2021, the Corporation was in compliance with all with all credit agreement covenants and limitations associated with its long-term debt.

22. Financial instruments and risk management:

Fair value disclosure

The carrying values of accounts receivable, unbilled revenue, and the revolving term facility, accounts payable and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair values of customer deposits approximate their carrying amounts taking into account interest accrued on the outstanding balance. Cash is measured at fair value.

The swap agreements are measured at fair value, which is provided by a third-party, banking institution and is based on market rates at the date of the valuation. The valuation of the interest rate swaps resulted in an unrealized gain recorded on the statement of financial position at December 31, 2022 of $784,886 (2021 - $938,948 unrealized loss).

The fair value of the long-term borrowings is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The carrying amounts and fair values of the Corporation's long-term loans consist of the following:

22. Financial instruments and risk management (continued):

	2022	2021
Carrying amounts:		
Demand notes payable, 7.25%	$15,600,000	$15,600,000
Term Loan 2.93% maturing May 1, 2038 plus stamping fee of 0.42%	9,875,000	10,366,000
Term Loan 2.62% maturing November 25, 2025	665,476	882,194
Total	**$26,140,476**	**$26,848,194**

	2022	2021
Fair values:		
Demand notes payable valued based on current revolving credit facility rate of 3.95%	$12,556,106	$16,422,603
Term Loan 2.93 % plus stamping fee of 0.42% booked at market value	9,581,114	11,304,948
Term Loan 2.62% maturing November 25, 2025, booked at market interest rate of 2.95%	609,697	865,230
Total	**$22,746,917**	**$28,592,781**

Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed. The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

a) *Credit risk*

The Corporation is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The Corporation's credit risk associated with accounts receivable and unbilled revenue is primarily related to electricity bill payments from electricity customers. The Corporation obtains security deposits from certain customers in accordance with direction provided by the OEB and as outlined in the Corporation's conditions of service. As of December 31, 2022, the Corporation held security deposits related to electricity receivables in the amount of $957,164 (2021 - $1,061,051).

22. Financial instruments and risk management (continued):

(a) *Credit risk (continued)*

As at December 31, 2022, there were no significant concentrations of credit risk with respect to any one customer. No single customer accounts for revenue in excess of 5% of total distribution revenue. The Corporation earns its revenue from a broad base of approximately 21,000 customers (2021 - 21,000 customers) located throughout its service territory.

The credit risk and mitigation strategies with respect to unbilled revenue are the same as for accounts receivable. The credit risk related to cash is mitigated by the Corporation's treasury policies on assessing and monitoring the credit exposures of counterparties.

Credit risk associated with electricity accounts receivable and unbilled revenue (electricity only) is as follows:

	2022	**2021**
Not more than 30 days	$ 6,448,968	$ 6,635,586
More than 30 but less than 90 days	405,840	295,071
More than 90 days	167,531	179,511
Less allowance for impairment	(173,017)	(178,684)
Unbilled revenue	4,783,498	5,230,771
	$ 11,632,820	**$12,162,255**

As at December 31, 2022, the Corporation's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for impairment was required for these balances.

Reconciliation between the opening and closing allowance for impairment is as follows:

	2022	**2021**
Balance, beginning of year	$ 178,684	$ 152,435
Provision for impairment	**53,870**	120,944
Write offs	(72,374)	(108,245)
Recoveries	12,837	13,550
Balance, end of year	**$ 173,017**	**$ 178,684**

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at year end. Unbilled revenue is considered current and no provision for impairment was established as at December 31, 2022 (2021 – nil).

(b) *Interest rate risk*

The Corporation is exposed to fluctuations in interest rates for the valuation of its employee future benefit obligations (note 12). The Corporation is also exposed to short-term interest rate risk on the net of cash position and short-term borrowings under its Revolving Credit Facility and customer deposits. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments and taking action as necessary to maintain an appropriate balance.

22. Financial instruments and risk management (continued):

(b) Interest rate risk (continued)

As at December 31, 2022, aside from the valuation of its employee future benefit obligations, the Corporation was exposed to interest rate risk predominately from short-term borrowings under its revolving credit facility and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation estimates that a 100 basis point increase in short-term interest rates, with all other variables held constant, would result in an increase of approximately $61,266 (2021 - $17,921) to annual finance costs. A decrease of 100 basis points would result in a reduction in financing costs of $61,266 (2021 – $17,921).

(c) Liquidity risk

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and monitors cash balances daily. The Corporation’s objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

The Corporation has a revolving credit facility available of $10,000,000 with a Canadian chartered bank. As at December 31, 2022, $3,720,132 (2021 - $17,428) was drawn on this facility.

As a purchaser of electricity through the Independent Electricity System Operator (“IESO”), the Corporation is required to provide security to minimize the risk of default based on its expected activity in the market. The IESO may draw on this security if the Corporation fails to make payment required by a default notice issue by the IESO. The Corporation has a $3.6 million revolving term facility by way of a letter of guarantee with Royal Bank, of which $3,095,139 (2021 - $3,095,139) has been assigned to secure the prudential support required by the IESO.

The majority of accounts payable, as reported on the statement of financial position, is due within 30 days.
Liquidity risks associated with financial commitments are as follows:

22. Financial instruments and risk management (continued):

Contractual cash flows, including interest, at year end are:

December 31, 2022

	Carrying Amounts	Total	Due within 1 year	Due within 1 to 5 years	Due> 5 years
Revolving credit facility	$ 3,741,355	$ 3,741,355	$ 3,741,355	$ -	$ -
Accounts payable and accrued liabilities	8,658,017	8,658,017	8,658,017	-	-
Due to City of Stratford	624,251	624,251	624,251	-	-
Demand notes payable	15,600,000	15,600,000	15,600,000	-	-
Term Loan 2.93 % plus stamping fee of 0.42%	9,875,000	12,645,318	828,224	3,308,138	8,508,956
Term Loan 2.62% maturing November 25, 2025	665,476	691,894	237,221	454,673	-
	$ 39,164,099	$ 41,960,835	$ 29,689,068	$ 3,762,811	$ 8,508,956

December 31, 2021

	Carrying Amounts	Total	Due within 1 year	Due within 1 to 5 years	Due> 5 years
Revolving credit facility	$ 17,428	$ 17,428	$ 17,428	$ -	$ -
Accounts payable and accrued liabilities	9,902,642	9,902,642	9,902,642	-	-
Due to City of Stratford	625,460	625,460	625,460	-	-
Demand notes payable	15,600,000	15,600,000	15,600,000	-	-
Term Loan 2.93 % plus stamping fee of 0.42%	10,366,000	13,475,135	829,817	3,311,494	9,333,824
Term Loan 2.62% maturing November 25, 2025	882,194	929,115	237,221	691,894	-
	$ 37,393,724	$ 40,549,780	$ 27,212,568	$ 4,003,388	$ 9,333,824

23. Commitments and contingencies:

Operating leases

The Corporation entered into a non-cancellable operating lease for service centre space for a period of five years dated November 15, 2015. The contract is subject to an annual increase based on the Ontario Consumer Price Index. Minimum lease payments required are $997 per month for 2022.

Connection and cost recovery agreement - St. Mary's transformer station

The Corporation and Hydro One Networks Inc. entered into a twenty-five-year capital cost recovery agreement ("CCRA") in September 2002 relating to Hydro One Networks Inc. building new feeder positions at the existing St. Mary's Transformer Station. Under the terms of the agreement, the Corporation has guaranteed new load growth which, if not met, would require the Corporation to provide a financial contribution toward the capital investment of the transformer station.

The CCRA has been trued-up effective July 5, 2013. Since load growth had fallen below a target amount, a cumulative contribution in the amount of $550,200 has been paid to Hydro One Networks. This amount has been recorded as an intangible asset subject to 15-year amortization over the remaining life of the agreement. The agreement was subject to true up effective on the fifteenth year of the agreement in July 2018 however, this has not been completed by Hydro One Inc. It is possible that the Corporation may owe a further payment as a result of the agreement but an estimate of any amount owing is not possible at December 31, 2022 given the nature of the variables included in the calculation. The need for a contribution will be determined by Hydro One Networks Inc. based on actual new load growth.

Connection and cost recovery agreement-Stratford transformer station ("Festival Hydro MTS1")

The Corporation and Hydro One Networks Inc. entered into a twenty-five-year CCRA in November, 2012, relating to Hydro One Networks Inc. building a new 230kV line to connect Festival Hydro`s MTS1 to Hydro One`s 230kV circuit. Under the terms of the agreement, the Corporation has guaranteed new load growth which, if not met, would require the Corporation to provide a financial contribution toward the capital investment. The CCRA is trued-up (a) following the fifth and tenth anniversaries of the in-service date; and (b) following the fifteenth anniversary of the in-service date if the actual load is 20% higher or lower than the load forecast at the end of the tenth anniversary of the in-service date. The fifth anniversary of the in-service date was in November 2017. The need for a contribution will be determined by Hydro One Networks Inc. based on actual new load growth.

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation’s financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (“MEARIE”). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2022, no assessments had been made.

24. Guarantee:

The Corporation has guaranteed the bank loan of QR Fibre, a company related through common ownership, to the extent of $4,500,000. In addition, the Corporation has entered into a Guarantee Indemnification Agreement to ensure compliance with the Affiliation Relationships code for Electricity Distributors and Transmitters and mitigate its risk exposure. No amount has been recorded in these financial statements as the Corporation does not expect to have to honour its guarantee.

25. Subsequent event:

The shares of QR Fibre Inc. held under common control were sold on January 31, 2023 for proceeds of $50,000. As of the date of sale, the Corporation is no longer obligated to honour the guarantee for the bank loan of QR Fibre.

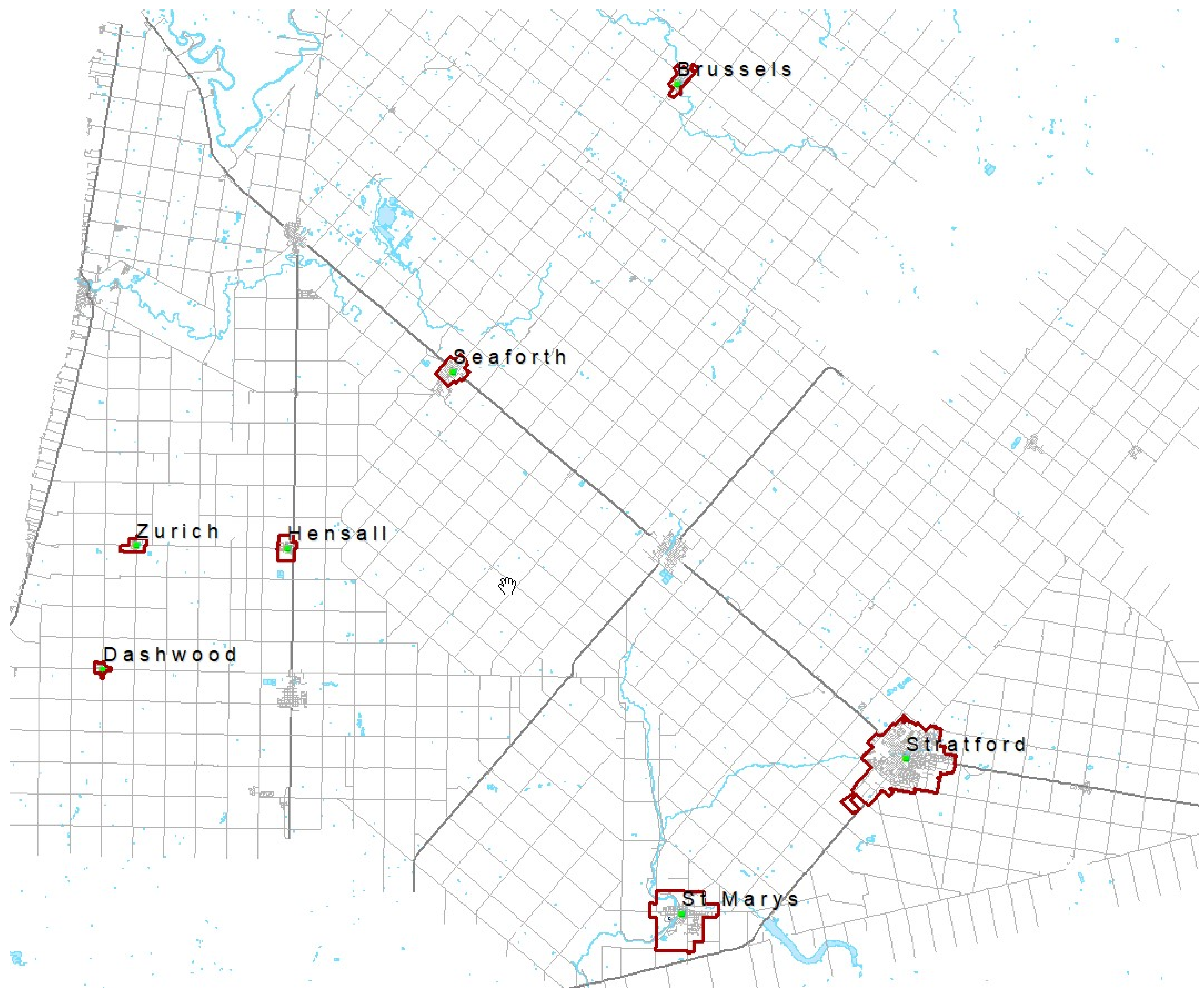
26. Comparative figures:

Certain comparative figures have been restated to conform to the current year presentation.

Attachment 1 –14

FHI Map of Service Territory

Map of Festival Hydro Service Territory



Attachment 1 –15

Organization Chart

Last Revised: *November 20, 2023*

Attachment 1 –16

FHI 2022 OEB Scorecard & MD&A

Scorecard - Festival Hydro Inc.

7/31/2023

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	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		99.25%	96.99%	95.31%	97.89%	95.92%		90.00%	
		Scheduled Appointments Met On Time		98.93%	98.50%	97.69%	98.88%	97.70%		90.00%	
		Telephone Calls Answered On Time		87.59%	88.45%	98.86%	91.71%	90.42%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.99	99.99	99.93	100	99.99			
		Billing Accuracy		99.95%	99.99%	99.96%	99.98%	99.97%		98.00%	
		Customer Satisfaction Survey Results		97%	97%	91	91	93			
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		81.00%	81.00%	80.00%	77.00%	77.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	1	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.383	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.92	1.79	1.27	1.95	0.81			1.35
		Average Number of Times that Power to a Customer is Interrupted [2]		0.73	1.78	1.00	1.63	0.77			1.31
	Asset Management	Distribution System Plan Implementation Progress		103.6	112	92	105	95			
	Cost Control	Efficiency Assessment		4	3	3	3	3			
		Total Cost per Customer [3]		$658	$650	$629	$614	$674			
		Total Cost per Km of Line [3]		$53,904	$53,219	$51,767	$50,551	$52,180			
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%	100.00%	100.00%	100.00%				
		New Micro-embedded Generation Facilities Connected On Time		100.00%			100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.50	0.53	0.54	0.51	0.46			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.19	1.11	1.04	0.99	0.97			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	9.30%	9.30%	9.30%			
			Achieved	8.30%	9.10%	8.89%	9.93%	9.25%			

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

2022 Scorecard Management Discussion and Analysis (“2022 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 2022 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

Festival Hydro Inc. (“Festival”) is a locally owned distribution company (“LDC”) servicing over 22,000 customers within a 45-sq. km urban territory in the municipalities of Stratford, St. Marys, Seaforth, Hensall, Zurich, Dashwood and Brussels. Festival is committed to maintaining a safe, reliable, and efficient electricity distribution system and providing quality service to its customers.

In 2022, Festival Hydro exceeded all OEB Scorecard performance targets. Festival is pleased with its Scorecard results achieved within each of the four performance outcome measures of customer focus, operational effectiveness, public policy responsiveness and financial performance.

Over the past several years Festival Hydro has made customer experience a top priority while also managing the challenges that arose through the covid pandemic. Festival had made several improvements to its website, paperless processes and online forms which allowed for a quick and relatively seamless transition for our customers and staff. In 2022, Festival also reopened its doors to the public with reduced hours. This allowed for customer engagement and service with the local community while still being able to manage staffing time and costs. Festival has also worked hard to improve reliability and is focused on continuing to reduce outages where possible. Festival is in the early stages of implementing a customer outage map and a new customer information system which will allow for better tools and communication opportunities with customers. Festival is committed to continuous improvement through its customer service activities, reliability, people and safety and financial performance.

Service Quality

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

In 2022, Festival connected 95.92% (282 of 294 requested) of its eligible low-voltage residential, small business and microFIT customer connections (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. This is above the OEB-mandated threshold of 90%. The high score reflects Festival’s commitment to quality and timely customer service.

- **Scheduled Appointments Met On Time**

Festival met 97.70% or 1.018 appointments on time of the 1.042 scheduled in 2022 (in 2021 794 or 98.88% of appointments were met on time) to complete work for special meter reads, reconnects, locates, or other work requiring an appointment to be performed. Festivals' score continues to significantly exceed the industry target of 90%. This performance category once again reflects Festival's commitment to quality and timely customer service.

- **Telephone Calls Answered On Time**

In 2022, Festival's customer service representatives received 18,651 customer related calls. This compares to 19,185 customer calls received in 2021. A customer service representative answered these calls in 30 seconds or less 90.42% of the time. This is a slight decrease from 2021's performance measurement which measured 91.71%. Festival's result significantly exceeds the OEB mandated 65% target for timely call response and demonstrates Festival's commitment to timely customer service. Festival continues to investigate the addition of enhanced features on the website to allow customers a greater range of self-serve options, which will help reduce call volumes and to improve the percentage of calls answered within 30 seconds.

Customer Satisfaction

- **First Contact Resolution**

Specific customer satisfaction measurements have not been formally defined across the industry. The OEB instructed all electricity distributors to review and develop measurements in these areas and to be tracking by July 1, 2014. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each electricity distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

First contact resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors. In July 2014, Festival implemented a first contact resolution process whereby at the end of a customer phone call, our customer service representative records whether the customer's issue or reason for calling was satisfactorily resolved on their first call. Of the total customer calls received in 2022, 99.99% were found to be resolved after the first call to Festival.

- **Billing Accuracy**

During 2022, over 270,000 bills were issued for which Festival achieved a billing accuracy rate of 99.97%. This amount is a slight decrease from the 2021 99.98% result achieved. Festival's results exceeded the prescribed OEB target of 98% and are a result of the emphasis that Festival places on great value in internal processes that allow for the highest standard of billing accuracy to be achieved.

- **Customer Satisfaction Survey Results**

The OEB introduced the customer satisfaction survey results measure in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year.

During 2022, Festival issued its fifth customer satisfaction survey. The overall informed satisfaction score was calculated at 93% which is 2% higher than what was reported in 2020. If the neutral and don't know scores are removed, the core measure is 96% compared to 96% in 2020. These results indicate a consistently high level of service for customers.

Festival was pleased with the survey results. Festival will continue to use feedback from the survey responses to drive decisions regarding initiatives that could be pursued to improve customer satisfaction. The next customer survey is scheduled for 2024.

Safety

- **Public Safety**

The Ontario Energy Board introduced these safety measures in 2015. The measures look at safety from a customer's point of view as safety of the distribution system is a high priority. The safety measures are generated by the Electrical Safety Authority (ESA) and include three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

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

    In 2015, the ESA launched a public awareness survey among a representative sample of Festival's territory population on behalf of Festival Hydro. The survey gauged awareness levels of key electrical safety concepts related to distribution assets and was based on a template survey provided by the ESA. The survey provided a benchmark of levels of awareness including identifying gaps where additional education and awareness efforts may be required. The survey is conducted every other year and in 2021 Festival scored 77% on this survey. This is a slight decrease from its last survey. Festival is active in using social media as a method of outreach to encourage public awareness and will look for additional opportunities to educate the public on electrical safety.

  - **Component B – Compliance with Ontario Regulation 22/04**

    Festival has been in compliance with Ontario Regulation 22/04 since it was introduced as a measure. This has been achieved as a result of Festival's strong commitment to safety and adherence to company safety procedures and practices. Ontario Regulation 22/04 establishes objective-based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications, and inspection of construction before they are put into service.

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

    In 2022, Festival saw no serious electrical incidents; a target it strives to achieve. Festival's commitment to the safety of the public and our employees remains our number one priority.

System Reliability

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

In 2015 the Ontario Energy Board established a measure for distributors related to the average number of hours that power to a customer is interrupted. This measure compares the annual statistic to the 5-year as the target for the utility. The result for 2022 of 0.81 is lower than Festival's 5-year target of 1.35. The main reason for this was a large decrease in the number of outage minutes due to adverse weather events and tree contacts. While significant weather events were seen, Festival Hydro's system proved very resilient. This comes from the continued investment in vegetation management, and capital asset replacement programs. Through recent years, Festival's score is historically lower than the provincial average when compared to the annual OEB Yearbook of Electricity Distributors. However, the comparison could not yet be completed as the 2022 provincial results were not yet available at the time of preparing the 2022 Scorecard MD&A.

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

Festival's average number of times that power to a customer is interrupted (i.e. frequency) of 0.77 is lower than previous years. The OEB introduced a measure in 2015 with expectations that distributors be within the 5-year target, similar to the measure above. Festival's result of 0.77 is lower than our 5-year target of 1.31. This target could not be compared to the provincial average as the 2022 provincial results were not yet available at the time of preparing the 2022 Scorecard MD&A. The decrease is due to significantly lower frequencies of tree contacts and adverse weather outages compared to previous years.

Asset Management

- **Distribution System Plan Implementation Progress**

Distribution System Plan (DSP) implementation progress is a performance measure instituted by the OEB starting in 2014. Consistent with other new measures, utilities were given an opportunity to define this measure in the manner that best fits their organization.
This measure is intended to assess the effectiveness of planning and implementing the DSP. As part of Festival's 2015 COS application, our 5-year distribution system plan was developed. The DSP outlines Festival's forecasted capital expenditures which are required to maintain and expand Festival's electricity system in order to serve our current and future customers over the period 2015 through 2019. Festival measures the progress of its capital expenditures as a ratio of actual total capital expenditures in the year compared to the total amount of planned capital expenditure for the year included in the DSP. Festival Hydro has not submitted a new COS Application since 2015, but prepared a new five year plan for 2020-2024. In addition, Festival prepares more specific annual capital budgets that are approved by its board. In 2022, Festival was at 95% of planned capital spending, indicating Festival spent less than planned on distribution capital. The majority of the shortfall in Capital spending can be attributed to delays in supply chain postponing the delivery of a piece of large equipment.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The ranking is based on a total cost approach taking into account the amounts spent on capital and infrastructure reinvestments and the amounts spent on operations, maintenance, and administration. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs.

In 2019, Festival improved on its ranking from 2018 and was placed in Group 3. A Group 3 distributor is defined as having actual costs within 10% of predicted costs. The Group 3 rating was an anticipated objective of Festival, as following a number of years of sustained higher investment to improve the infrastructure within the smaller towns purchased by Festival, efficiencies were realized resulting in a decrease in the total cost per customer. In 2022, Festival maintained its Group 3 position.

Based on the 2022 PEG results, Festival's total cost decreased by 2.8% which was better than the average of LDCs at a decrease of 2.1%. Festival Hydro total costs continue to decrease with cost efficiency results for 2019 – 2021 reported at 1.4% and results from 2019-2021 at -1.4%.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of Festival's capital and operating costs as per the PEG report and dividing this cost figure by the total number of customers that Festival serves. The cost performance result for 2022 is $674 per customer, which is a 9.77% increase from 2021. Festival's 2022 increase in total cost can be evenly attributed between higher administrative costs and increases to capital costs towards the distribution system. In 2021, there were several senior staff vacancies through portions of the year which increased administration costs when these vacancies were filled in 2022.

Festival has managed to keep its costs reasonable despite having to deliver on growth in wage and benefits costs, investments in new information systems technology and the renewal and growth of the distribution system. In 2022, inflation increased significantly, and the supply chain was strained which impacted almost all costs within the utility. This trend is anticipated to continue in the near future.

Festival plans to continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts, as demonstrated in Festival's Distribution Plan filed as part of its 2015 Cost of Service application. Festival will continue to implement productivity and improvement initiatives to help offset some of the increases in costs.

- **Total Cost per Km of Line**

This measure uses the same total cost as used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Festival operates to serve its customers. Festival's 2022 rate is $52,180 per Km of line, a 3.22% increase over 2021.

Festival generally experiences minimal growth in its total kilometers of lines due to low annual customer and population growth rate and, as a result, the increase in this measure is mainly driven by total costs. Festival continues to seek innovative solutions to improve value to the customer or to mitigate cost increases where possible.

Connection of Renewable Generation

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

Electricity distributors are required to conduct connection impact assessments (CIAs) within 60 days of receiving authorization from the ESA. The score does not appear on the scorecard as the filing requirement was removed from the Reporting and Record-keeping Requirements (RRR). In 2022, Festival had one application and completed the CIA within the prescribed time limit.

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

In 2022, Festival connected ten new micro-embedded renewable generation facilities (microFIT/Net-meter projects of less than 10kW). Festival was able to connect these facilities 100% of the time within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. Festival works closely with its customers to minimize connection issues and to ensure projects are connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations.

Festival’s current ratio decreased to 0.46 in 2022 from 0.51 in 2021 ratio. The reason for the ratio being substantially less than 1.00 is because of the shareholder loan. The repayment term on the promissory note is “on demand” and, as such, that borrowing instrument is classified as a current liability. If the impact of the promissory note is removed, Festival then has a current ratio of 0.91 for 2022 (1.11 for 2021). The ratio is also affected by an increase in our bank indebtedness as a result of our increased capital spending than in previous years.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

Festival continues to maintain a debt to equity structure that is less than the deemed 60%/40% capital mix as set out by the OEB at 0.97. Festival is expected not to exceed the OEB deemed ratio of 1.5 in the near term.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

Festival's current deemed regulatory return on equity (ROE) of 9.3% was approved by the OEB as part of Festival's 2015 Cost of Service Application. The deemed regulatory return on equity is traditionally only changed as part of a Cost of Service Application. The OEB expects a distributor to earn within +/- 3% of the deemed return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and cost structure.

- **Profitability: Regulatory Return on Equity – Achieved**

Festival achieved a regulatory return of 9.25% in 2022. This is within the 300-basis points band noted above and demonstrates strong financial performance and cost management.

Note to Readers of 2022 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. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Attachment 1 –17

Benchmarking Model

Data Required for Cost Benchmarking

Festival Hydro Inc.

Select Distributor from Dropdown Box: Festival Hydro Inc.

Required Item		History 2020	History 2021	History 2022	History 2023	Bridge 2024	Test 2025	Additional Year for Custom IR 2026	The values provided for 2021-2026 are placeholder values that must be replaced	
	Gross Capital Cost Additions Data									
1	Total Gross Capital Additions	3,224,478	3,865,723	4,175,358	5,337,210	7,716,940	7,736,538		Enter Values	
2	HV Gross Capital Additions	-	143,417	86,263	212,043	150,000	274,600		Enter Values	
	Output and Other Business Conditions									
3	Number of Customers	21,654	21,908	22,211	22,397	22,646	22,898		Enter Values	
4	Delivery Volume	590,935,764	597,239,898	611,606,381	600,491,418	603,790,041	602,361,930		Enter Values	
5	Annual Peak Demand	116,734	116,734	116,734	116,734	116,734	116,734		Enter Values	
6	Distribution Circuit-km	263	266	287	290	290	290		Enter Values	
7	Ten Year Customer Growth Percentage	10.60%	10.17%	10.74%	10.95%	11.65%	11.87%		Enter Values	
	Inflation Measures									
8	Wage Growth	2.00%	3.05%	3.05%	3.50%	2.30%	2.30%	2.30%	Enter values. The value provided is an arbitrary placeholde	The applicability of the wage index used in the benchmarking analysis is under review by
9	Growth in Economy-wide Inflation	2.00%	4.00%	5.86%	3.80%	5.90%	5.90%	5.90%	Enter values. The value provided is an arbitrary placeholde	the OEB. Please refer to developments in EB-2021-0212 for current thinking about
10	Rate of Return (WACC)	5.32%	5.00%	5.46%	6.67%	6.50%	6.50%	6.50%	Enter Values. The default value provided is for 2020.	inflation measures.
	OM&A Expenses Included in Cost Benchmarking									
Choose a Method:	N **Use Method 1 [1A - 1B + 1C]**	6,002,784	-	-	-	-	-	-	Formula	
	Y **Use Method 2 [2A - 2B + 2C]**	6,002,784	5,861,377	6,618,860	7,046,474	7,957,326	8,915,023	-	Formula	
11	**OM&A Values Transfered to Calculations Worksheet**	6,002,784	5,861,377	6,618,860	7,046,474	7,957,326	8,915,023	-	Formula	

Method 1: Enter Values Calculated Elsewhere

		2020	Enter Values Supported by Separate Calculations							
1A	Total OM&A Consistent with accounts included in [2B]	6,068,153							Enter Values	
1B	HV Cost (Accounts 5014, 5015, and 5112) if included in total	99,123							Enter Values	
1C	LV Adjustment	33,754							Enter Values	

Method 2: Enter Detailed Data

OM&A Data

		2020	2021	2022	2023	2024	2025	2026	
5005	Operation Supervision and Engineering	275,259	68,739	128,633	243,931	291,276	260,586		Enter Values
5010	Load Dispatching	73,209	109,891	108,536	88,599	94,024	129,388		Enter Values
5012	Station Buildings and Fixtures	37,338	30,350	32,945	32,971	33,329	45,701		Enter Values
5014	Transformer Station Equipment - Operation Labor	2,056	8,030	57,109	168,855	150,479	157,012		Enter Values
5015	Transformer Station Equipment - Operation Supplies and Expenses	88,918	86,614	92,465	59,304	64,181	66,758		Enter Values
5016	Distribution Station Equipment - Operation Labor	-	23,661	-	-	-	-		Enter Values
5017	Distribution Station Equipment - Operation Supplies and Expenses	-	34,123	-	-	-	-		Enter Values
5020	Overhead Distribution Lines and Feeders - Operation Labor	42,352	4,828	19,565	17,279	27,441	27,001		Enter Values
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	40,226	3,547	45,189	35,141	47,091	54,123		Enter Values
5035	Overhead Distribution Transformers - Operation	2,769	311	2,481	4,659	6,680	6,571		Enter Values
5040	Underground Distribution Lines and Feeders - Operation Labor	2,379	8,515	2,575	4,037	3,368	3,314		Enter Values
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	306	167,207	457	408	456	479		Enter Values
5055	Overhead Distribution Lines and Feeders	9,820	188,676	13,072	7,347	15,605	16,353		Enter Values
5065	Meter Expense	282,484	6,192	263,742	233,530	286,988	314,841		Enter Values
5070	Customer Premises - Operation Labor	148,766	8,031	199,902	197,019	243,006	250,840		Enter Values
5075	Customer Premises - Operation Materials and Supplies	4,951	-	6,928	19,514	9,142	17,599		Enter Values
5085	Miscellaneous Distribution Expense	6,601	6,322	13,720	5,302	6,396	7,416		Enter Values
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-		Enter Values
5095	Overhead Distribution Lines and Feeders - Rental Paid	13,543	8,030	8,763	9,318	10,202	10,568		Enter Values
5096	Other Rent (Distribution)	-	86,614	-	-	-	-		Enter Values
	Subtotal: Operation	**1,030,977**	**755,036**	**996,081**	**1,127,215**	**1,289,665**	**1,368,552**	**-**	Formula
5105	Maintenance Supervision and Engineering	-	-	-	-	-	-		Enter Values
5110	Maintenance of Buildings and Fixtures	3,922	13,440	16,934	24,543	32,548	16,092		Enter Values
5112	Maintenance of Transformer Station Equipment	8,150	28,998	26,184	77,605	10,000	91,100		Enter Values
5114	Maintenance of Distribution Station Equipement	930	-	127	2,950	-	2,000		Enter Values
5120	Maintenance of Poles, Towers and Fixtures	54,334	71,949	113,835	77,875	70,619	70,712		Enter Values
5125	Maintenance of Overhead Conductors and Devices	109,766	86,424	111,440	104,263	124,259	123,648		Enter Values
5130	Maintenance of Overhead Services	857,905	849,991	949,266	897,069	1,063,171	1,133,279		Enter Values
5135	Overhead Distribution Lines and Feeders - Right of Way	177,728	169,432	192,003	181,928	177,195	211,179		Enter Values
5145	Maintenance of Underground Conduit	39,214	42,290	35,270	34,373	33,892	33,840		Enter Values
5150	Maintenance of Underground Conductors and Devices	78,332	99,653	86,327	78,777	94,943	107,649		Enter Values
5155	Maintenance of Underground Services	77,270	140,661	165,037	152,500	149,688	148,750		Enter Values
5160	Maintenance of Line Transformers	22,191	41,935	30,428	24,553	29,645	29,848		Enter Values
5175	Maintenance of Meters	108,581	144,693	180,609	161,048	173,557	178,667		Enter Values
	Subtotal: Maintenance	**1,538,324**	**1,689,466**	**1,907,462**	**1,817,483**	**1,959,517**	**2,146,761**	**-**	Formula
5305	Supervision (Billing and Collection)	83,485	50,148	67,148	77,354	81,188	85,594		Enter Values
5310	Meter Reading Expense	224,735	225,984	229,305	232,638	224,240	265,211		Enter Values
5315	Customer Billing	595,825	639,161	671,770	708,003	841,420	938,614		Enter Values
5320	Collecting	120,191	113,433	129,295	149,071	159,862	171,583		Enter Values
5325	Collecting - Cash Over and Short	-	-	-	-	-	-		Enter Values

5335	5330	Collection Charges	-	-	-	-	-	-		Enter Values
	5340	Miscellaneous Customer Account Expenses	144,978	143,787	132,098	154,688	163,680	174,474		Enter Values
		Subtotal : Billing and Collections	**1,169,215**	**1,172,513**	**1,229,616**	**1,321,753**	**1,470,390**	**1,635,476**	**-**	Formula
	5405	Supervision (Community Relations)	1,015	1,015	1,115	-	1,188	1,248		Enter Values
	5410	Community Relations - Sundry	-	-	-	-	-	-		Enter Values
	5420	Community Safety Program	11,253	-	-	-	8,319	18,179		Enter Values
	5425	Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-	-		Enter Values
		Subtotal: Community Relations	**12,268**	**1,015**	**1,115**	**-**	**9,507**	**19,427**	**-**	Formula
	5605	Executive Salaries and Expenses	983,543	926,808	1,063,300	1,474,378	1,783,566	2,032,174		Enter Values
	5610	Management Salaries and Expenses	-	-	-	-	-	-		Enter Values
	5615	General Administrative Salaries and Expenses	511,467	544,383	578,681	509,064	437,145	457,694		Enter Values
	5620	Office Supplies	173,797	193,537	209,718	228,595	261,138	292,347		Enter Values
	5625	Administrative Expense Transferred - Credit	-	-	-	-	-	-		Enter Values
	5630	Outside Services Employed	103,693	148,308	156,165	197,067	182,000	221,100		Enter Values
	5640	Injuries and Damages	55,757	47,939	54,708	61,866	86,876	104,251		Enter Values
	5645	OMERS Pensions and Benefits	138,704	131,565	130,782	130,515	151,340	181,604		Enter Values
	5646	Employee Pensions and OPEB	-	-	-	-	-	-		Enter Values
	5647	Employee Sick Leave	-	-	-	-	-	-		Enter Values
	5650	Franchise Requirements	-	-	-	-	-	-		Enter Values
	5655	Regulatory Expenses	121,425	89,514	172,019	176,966	206,308	400,624		Enter Values
	5665	Miscellaneous General Expenses	98,237	115,270	103,293	150,395	127,333	145,554		Enter Values
	5670	Rent (Administrative and General)	-	-	-	-	-	-		Enter Values
	5672	Lease Payment Expense	-	-	-	-	-	-		Enter Values
	5675	Maintenance of General Plant	120,029	123,214	143,961	105,100	162,735	166,625		Enter Values
	5680	Electrical Safety Authority Fees	10,718	10,750	10,863	10,907	11,000	11,550		Enter Values
		Sutotal: A&G Expenses	**2,317,370**	**2,331,289**	**2,623,490**	**3,044,852**	**3,409,440**	**4,013,523**	**-**	Formula
	5635	Property Insurance	-	-	-	-	-	-	-	Enter Values
	6210	Life Insurance	-	-	-	-	-	-	-	Enter Values
		Subtotal: Insurance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	Formula
	5515	Advertinsing	-	-	-	-	-	-	-	Enter Values
		Subtotal Advertising	**-**	**-**	**-**	**-**	**-**	**-**	**-**	Formula
	2A	**Total of Above Accounts Used for Benchmarking**	6,068,153	**5,949,319**	**6,757,764**	**7,311,302**	**8,138,520**	**9,183,739**	**-**	Formula
Adjustments to OM&A for Benchmarking										
		5014	2,056	8,030	57,109	168,855	150,479	157,012	-	Formula
		5015	88,918	86,614	92,465	59,304	64,181	66,758	-	Formula
		5112	8,150	28,998	26,184	77,605	10,000	91,100	-	Formula
	2B	**Subtotal: HV Adjustment (to subtract from cost)**	**99,123**	**123,642**	**175,758**	**305,763**	**224,660**	**314,870**	**-**	**Formula**
	2C	**LV Adjustment**	**33,754**	**35,700**	**36,854**	**40,935**	**43,467**	**46,155**		**Enter Values**

Benchmarking Calculations for LDC Forecasting

Selected LDC: Festival Hydro Inc.

Line Reference Number	Row #	Account	2020	2021	2022	2023	2024	2025	2026
				Forecasted Values					

Section 1: Source Data and OM&A Calculations

[illegible]

Section 2: Actual Cost Calculations

[illegible]

Section 3: Predicted Cost Calculations

[illegible]

Line	Row #	Account	2020	2021	2022	2023	2024	2025	2026
128		Line km	263.00	266.00	287.00	290.00	290.00	290.00	-
129		2002-2013 Average Line km	268.93	268.74	269.88	271.06	272.11	273.11	257.93
130		Customers Ten Years Ago	19,579						
131		Ten Year Customer Growth Percentage	10.60%	10.17%	10.74%	10.95%	11.65%	11.87%	0.00%
132									
133		(Details of the predicted cost calculations may be hidden by using the +/- button to the left of row 248)							
134									
135		**Company Values for Variables Used in the Prediction Equation**							
136									
137		Constant	1.00	1.00	1.00	1.00	1.00	1.00	1.00
138		Capital Price / OM&A Price (WK)	0.1258	0.1212	0.1281	0.1451	0.1449	0.1486	0.1524
139		Customers (Y1)	21,654	21,908	22,211	22,397	22,646	22,898	-
140		Capacity (Y2)	116,734	116,734	116,734	116,734	116,734	116,734	116,734
141		Deliveries (Y3)	590,935,764	597,239,898	611,606,381	600,491,418	603,790,041	602,361,930	0
142		Average Line Length	268.9	268.7	269.9	271.1	272.1	273.1	257.9
143		Customers Added in last 10 years	10.60%	10.17%	10.74%	10.95%	11.65%	11.87%	0.00%
144		Trend	14	15	16	17	18	19	20
145									
146									
147		**Company-Specific Parameter Estimates***							
148	91	Constant	12.8157	12.8157	12.8157	12.8157	12.8157	12.8157	12.8157
149	92	Capital Price / OM&A Price (WK)	0.6221	0.6221	0.6221	0.6221	0.6221	0.6221	0.6221
150	93	Customers (Y1)	0.4520	0.4520	0.4520	0.4520	0.4520	0.4520	0.4520
151	94	Capacity (Y2)	0.1546	0.1546	0.1546	0.1546	0.1546	0.1546	0.1546
152	95	Deliveries (Y3)	0.0927	0.0927	0.0927	0.0927	0.0927	0.0927	0.0927
153	96	WKWK	0.1143	0.1143	0.1143	0.1143	0.1143	0.1143	0.1143
154	97	Y1Y1	(0.3584)	(0.3584)	(0.3584)	(0.3584)	(0.3584)	(0.3584)	(0.3584)
155	98	Y2Y2	0.2178	0.2178	0.2178	0.2178	0.2178	0.2178	0.2178
156	99	Y3Y3	0.1342	0.1342	0.1342	0.1342	0.1342	0.1342	0.1342
157	100	WKY1	0.0584	0.0584	0.0584	0.0584	0.0584	0.0584	0.0584
158	101	WKY2	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080
159	102	WKY3	(0.0024)	(0.0024)	(0.0024)	(0.0024)	(0.0024)	(0.0024)	(0.0024)
160	103	Y1Y2	0.1056	0.1056	0.1056	0.1056	0.1056	0.1056	0.1056
161	104	Y1Y3	0.0889	0.0889	0.0889	0.0889	0.0889	0.0889	0.0889
162	105	Y2Y3	(0.1906)	(0.1906)	(0.1906)	(0.1906)	(0.1906)	(0.1906)	(0.1906)
163	106	Average Line Length	0.2984	0.2984	0.2984	0.2984	0.2984	0.2984	0.2984
164	107	Customers Added in last 10 years	0.0175	0.0175	0.0175	0.0175	0.0175	0.0175	0.0175
165	108	Trend	0.0169	0.0169	0.0169	0.0169	0.0169	0.0169	0.0169
166									
167		**Sample Mean Values**							
168									
169		Constant	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
170		Capital Price / OM&A Price (WK)	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644
171		Customers (Y1)	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118
172		Capacity (Y2)	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146
173		Deliveries (Y3	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994
174		WKWK	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
175		Y1Y1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
176		Y2Y2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
177		Y3Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
178		WKY1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
179		WKY2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
180		WKY3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
181		Y1Y2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
182		Y1Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
183		Y2Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
184		Average Line Length	2.723	2.723	2.723	2.723	2.723	2.723	2.723
185		Customers Added in last 10 years	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286
186									
187									
188									
189		**2013 Values Logged and Mean Scaled (where applicable)**							
190									
191		Constant	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
192		Capital Price / OM&A Price (WK)	(0.2679)	(0.3049)	(0.2494)	(0.1246)	(0.1264)	(0.1012)	(0.0760)
193		Customers (Y1)	(1.0746)	(1.0630)	(1.0492)	(1.0409)	(1.0298)	(1.0188)	#NUM!
194		Capacity (Y2)	(1.0840)	(1.0840)	(1.0840)	(1.0840)	(1.0840)	(1.0840)	(1.0840)
195		Deliveries (Y3)	(1.0148)	(1.0042)	(0.9804)	(0.9988)	(0.9933)	(0.9957)	#NUM!
196		WKWK	0.0359	0.0465	0.0311	0.0078	0.0080	0.0051	0.0029
197		Y1Y1	0.5774	0.5649	0.5504	0.5417	0.5303	0.5190	#NUM!
198		Y2Y2	0.5876	0.5876	0.5876	0.5876	0.5876	0.5876	0.5876
199		Y3Y3	0.5149	0.5042	0.4806	0.4988	0.4933	0.4957	#NUM!
200		WKY1	0.2879	0.3241	0.2617	0.1296	0.1302	0.1031	#NUM!
201		WKY2	0.2904	0.3305	0.2703	0.1350	0.1370	0.1097	0.0824
202		WKY3	0.2719	0.3062	0.2445	0.1244	0.1255	0.1008	#NUM!
203		Y1Y2	1.1649	1.1523	1.1374	1.1283	1.1164	1.1044	#NUM!
204		Y1Y3	1.0906	1.0674	1.0287	1.0396	1.0230	1.0144	#NUM!
205		Y2Y3	1.1001	1.0886	1.0628	1.0827	1.0768	1.0793	#NUM!
206		Average Line Length	(2.3150)	(2.3157)	(2.3114)	(2.3071)	(2.3032)	(2.2996)	(2.3567)
207		Customers Added in last 10 years	82.41%	79.11%	83.51%	85.15%	90.59%	92.29%	0.00%
208		Trend	14.0000	15.0000	16.0000	17.0000	18.0000	19.0000	20.0000
209									
210		**Product of Parameter and 2013 Values**							
211									
212		Constant	12.816	12.81571	12.816	12.816	12.816	12.816	12.816
213		Capital Price / OM&A Price (WK)	(0.167)	(0.18968)	(0.155)	(0.077)	(0.079)	(0.063)	(0.047)
214		Customers (Y1)	(0.486)	(0.48048)	(0.474)	(0.470)	(0.466)	(0.461)	#NUM!
215		Capacity (Y2)	(0.168)	(0.16754)	(0.168)	(0.168)	(0.168)	(0.168)	(0.168)
216		Deliveries (Y3)	(0.094)	(0.09307)	(0.091)	(0.093)	(0.092)	(0.092)	#NUM!
217		WKWK	0.004	0.00531	0.004	0.001	0.001	0.001	0.000
218		Y1Y1	(0.207)	(0.20249)	(0.197)	(0.194)	(0.190)	(0.186)	#NUM!
219		Y2Y2	0.128	0.12796	0.128	0.128	0.128	0.128	0.128
220		Y3Y3	0.069	0.06765	0.064	0.067	0.066	0.067	#NUM!
221		WKY1	0.017	0.01893	0.015	0.008	0.008	0.006	#NUM!
222		WKY2	0.002	0.00265	0.002	0.001	0.001	0.001	0.001
223		WKY3	(0.001)	(0.00073)	(0.001)	(0.000)	(0.000)	(0.000)	#NUM!
224		Y1Y2	0.123	0.12173	0.120	0.119	0.118	0.117	#NUM!
225		Y1Y3	0.097	0.09485	0.091	0.092	0.091	0.090	#NUM!
226		Y2Y3	(0.210)	(0.20753)	(0.203)	(0.206)	(0.205)	(0.206)	#NUM!
227		Average Line Length	(0.691)	(0.69108)	(0.690)	(0.689)	(0.687)	(0.686)	(0.703)
228		Customers Added in last 10 years	0.014	0.01384	0.015	0.015	0.016	0.016	-
229		Trend	0.237	0.25409	0.271	0.288	0.305	0.322	0.339
230									
231		Log of Predicted Total Cost / OM&A Price	11.4853	11.490132	11.5482	11.6371	11.6623	11.7009	#NUM!
232		Real Predicted Total Cost / OM&A Price	97,280	97,746	103,596	113,222	116,115	120,681	#NUM!
233		OM&A Price	137.68	142.35	148.00	153.41	158.68	164.14	169.78
234		**Predicted Total Cost**	13,393,349	13,914,381	15,331,898	17,369,137	18,425,289	19,808,104	#NUM!
235									
236									

Section 4: Benchmarking Results

Line	Account	2020	2021	2022	2023	2024	2025	2026
237	Actual Cost	13,614,678	13,447,473	14,971,727	16,969,845	18,543,739	20,429,120	11,653,253
238	Predicted Cost	13,393,349	13,914,381	15,331,898	17,369,137	18,425,289	19,808,104	#NUM!
239	Actual less Predicted Cost	221,329	(466,907)	(360,171)	(399,292)	118,451	621,017	#NUM!
240	Percentage Difference (Arithmetic for Comparison)	1.65%	-3.36%	-2.35%	-2.30%	0.64%	3.14%	#NUM!

241								
242	Percent Difference (Logarithmic)	1.64%	-3.41%	-2.38%	-2.33%	0.64%	3.09%	#NUM!

[redacted]

Summary of Cost Benchmarking Results

Festival Hydro Inc.

Cost Benchmarking Summary	2020 (History)	2021 (History)	2022 (History)	2023 (History)	2024 (Bridge)	2025 (Test Year)
Actual Total Cost	13,614,678	13,447,473	14,971,727	16,969,845	18,543,739	20,429,120
Predicted Total Cost	13,393,349	13,914,381	15,331,898	17,369,137	18,425,289	19,808,104
Difference	221,329	(466,907)	(360,171)	(399,292)	118,451	621,017
Percentage Difference (Cost Performance)	**1.6%**	**-3.4%**	**-2.4%**	**-2.33%**	**0.64%**	**3.09%**
Three-Year Average Performance			-1.4%	-2.71%	-1.35%	0.47%
Stretch Factor Cohort						
Annual Result	3	3	3	3	3	3
Three Year Average			3	3	3	3

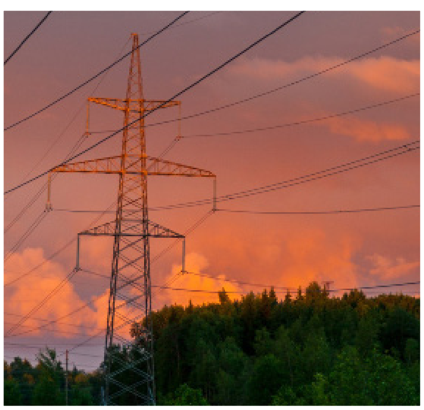
Attachment 1 –18

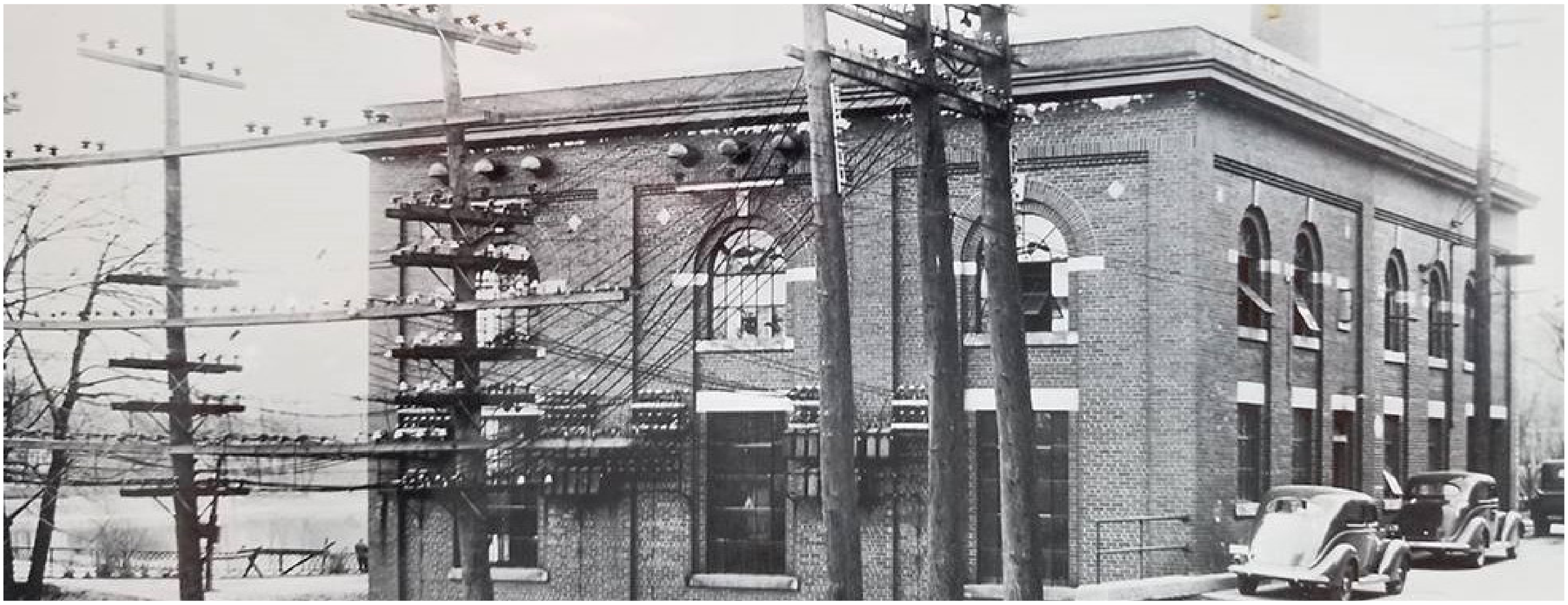
2022 Annual Report

Festival Hydro Inc.

2022

Year In Review





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Mission

To responsibly provide value to our customers, communities, shareholders, and employees through cost effective distribution of reliable and safe electric power.

Vision

We enable prosperity within our communities through exceptional people, partnerships, and performance.

Purpose

Powering lives, empowering communities.

Values

- People First through Positive Teamwork
- Accountability
- Honesty
- Commitment to Customers
- Trust

Meet Our Board & Executives

Geraldine Guthrie
Chair

John Tapics
Vice Chair

David Scott
Director

Mark Henderson
Director

Susan Nickle
Director

Martin Ritsma
Director

Brad Beatty
Director

Cody Sebben
Director

Jeff Graham
Chief Executive Officer

Alyson Conrad
Chief Financial Officer

Bryon Hartung
VP of Engineering and Operations

Jackie Wheal
Director, Human Resources/Health and Safety

Message from the CEO

To begin, I would like to welcome the new members to the Festival Hydro board who joined us in December and bid a fond farewell to those who are no longer directors. Thank you all for your guidance and contributions to the governance and oversight of Festival Hydro Inc. I feel grateful to have such a knowledgeable, friendly, and driven group of people helping to keep the organization powering forward.

2022 was a year of renewal and reopening. This marked the first year since the pandemic began in 2022 that Festival Hydro was able to welcome back customers for in-person service and host our staff all together for in-person events. These were highlights for us all as they marked the beginning of a new normal and we were provided the opportunity to come together, reconnect with old colleagues and finally meet new team members face to face who joined the company during the closure. The previous years brought many new challenges as we all learned how to work remotely, but I would like to express my gratitude for working with such a resilient and agile team of people who rose to the challenge and together we have made it to the other side.

This year the board and executive team undertook a midterm review of the strategic priorities identified at the planning meeting in May of 2019 to refresh, renew and realign the strategic plan and priorities to meet the changing needs of Festival Hydro Inc., our employees, our shareholder, and the communities we serve. This plan provides guidance for the development of our annual business plan and helps us reflect and refocus on who we are, what we do, what we can do, and who we are as a good corporate citizen.

With strong relationships in place with our shareholder, our board, investStratford, and our team, I look forward to seeing what successes await us in 2023!

Jeff Graham, President &CEO

Key Performance Indicator Highlights

Festival Hydro maintains an internal scorecard to measure and track performance encompassing:

- Financial Measures
- Reliability Measures
- Generation
- Safety
- Customer experience
- Human Resources
- Community Involvement
- Enterprise Risk

The full draft FHI Internal Scorecard for 2022 is included in the appendices of this document along with the 2022 IFRS Statements and the 2022 Audit Findings Report. The finalized Internal Scorecard will be provided to the board in September of 2023 after the OEB releases their scorecard information.

As was noted at the HR Committee and Board meetings in December 2022 was a very busy year and Management had substantially completed 2022 planned objectives.

- Distribution System Capital Projects were substantially completed except for some small overhead projects and spending totaled approximately 100% of budget.

- General Plant projects were substantially complete with some Software and Fleet spending deferred, and some Facilities projects advanced as capacity was available. Overall spending was 95% of budget, which is well within our spending target.

In relation to the FHI KPI metrics, it was an exceptional year as significant majority of targets were met successfully while the organization continued to actively recruit staff for organizational vacancies and retain current staff. Some areas of note from the 2022 Internal KPI Scorecard:

Financial Measures

Throughout 2022 the financial KPI's continued to track very well indicating the overall positive financial health of the organization and the ability to meet the shareholder's expectations for the 2022 dividend payout once the audited financials have been approved by the board of directors.

Two KPIs that were very close to but did not meet target (Liquidity and Debt servicing) fell short due to prudent decisions related to a new swap loan and timing of paying IESO invoices at month end while receiving customer payments at the beginning of the following month.

Reliability Measures

Festival hydro's reliability KPI's illustrate one of the best performance years on record. SAIDI and SAIFI are at some of the lowest rates ever and only one of 13 feeders had greater than 10 momentaries which was the 9M3 at 11 momentaries. Overall, this is indicative of prudent decision making and effectiveness of the projects that have been undertaken by FHI to improve reliability throughout our distribution system.

Safety

As a company that places an emphasis on safety it is pleasing to report that the results of the Safety KPI's are excellent. There were no lost-time injuries, and it is expected that we are fully compliant with the ESA with the report to be received in the coming months.

Only one of the tracked metrics was not met, that being "Number of 'safety concerns' reported in a calendar year". The Joint Health & Safety Committee continues to run communications and incentives to encourage staff to report any safety concerns that they identify.

Customer Experience

Customer experience metrics consistently show that the attention given to maintaining a positive relationship with our customers is effective. This is also evidenced by the remarkable results from the Customer Satisfaction Survey, setting overall satisfaction at 93%. The targets have been met in all categories and FHI has once again outperformed the OEB's expectations.

Human Resources

At the heart of our organization are our people, those who work to consistently meet and exceed the KPI targets. With numerous changes in the last couple years and a global pandemic, there were numerous challenges; however, staff morale and engagement appear to be very good as we have stabilized and returned to a new normal with hybrid working options. Many staff have expressed excitement about the renovations taking place at the admin building and seeing that move forward has helped to ease the challenges presented by having everyone shifted around within the remainder of the building.

Community Involvement

The newly formed voluntary staff committee that coordinates community engagement projects has numerous items in the works for the upcoming year that staff can opt to participate in. The couple events that staff could volunteer for in Q1 of the current year were met with excitement, great levels of participation, and indicate growing positive engagement of our team members.

We hope to continue to build on this momentum with the planned employee events and community involvement activities in 2023.

Enterprise Risk

Entering 2022 there were several questions surrounding potential volatility due to increasing inflation, supply chain concerns, recruitment challenges, and the ever-present threat of cyberattacks.

As the changing situations were monitored staff made decisions based on what they were seeing, such as getting agreements in place to ensure components for projects were available, priced reasonably, and delivered on time and the IT team continued to monitor cyber security concerns, and complete projects that will drive process efficiencies within the organization.

Overall, the risks to the organization have been well managed and monitored as is indicated by FHI's positive performance in the areas reported on the Internal Scorecard.

Other News

Tree Power 2022

Festival Hydro, the Upper Thames River Conservation Authority and City of Stratford's Energy and Environment Advisory Committee, once again offered residents an opportunity to purchase native hardwood species of trees for $25 per tree. This program is always met with much excitement and trees tend to sellout only hours after orders open. Several staff members volunteered to lend a hand on tree pick up day.

Peterborough Mutual Assistance- May 25-28

Festival Hydro sent a crew to assist with restorations in the Peterborough area after a damaging storm and tornado caused loss of power for more than 700,000 customers receiving power through Hydro One's distribution system.

Appendix

2022 Key Performance Indicators

2022 Independent Auditors Report

2022 Audited Financial Statements

Scorecard - Festival Hydro Inc. for December 31, 2022 - Draft

Performance Outcomes	Measures	2017	2018	2019	2020	2021	2022	Status	Target
Financial Measures To Maintain Financial Health by Meeting or Exceeding all KPI Measures	Liquidity - Current Ratio (excluding shareholder debt)	1.10	1.13	1.19	1.21	1.11	0.93		To exceed 1
	Debt to Equity	1.33	1.22	1.14	1.07	0.94	0.83		Not to exceed 60/40 (1.5)
	Debt Servicing (excluding shareholder debt)	1.83	1.92	1.83	1.8	2.03	1.93		Not less than 2.0x
	Dividend Payout Ratio	72.3	59.3	61.9	33.8	50	NA (updated in the fall)		Not to exceed 70% of adjusted NI
	Efficiency Assessment (PEG)	4	4	3	3	3	NA (updated in the fall)		To reach efficiency ranking of Group 3
	DSP Implementation Process	94.2	127.6 (2018), 103.6 (5 yr)	134.8% (2019), 112% (5 year)	79% - 2020	105% (2021), 92% (5 year)	95% (2022), 93% (5 Year)		To maintain single year budget within +-10% and 5 year budget within +-5%
	Total Cost per Customer (OEB measure)	612	658	650	629	614	NA (updated in the fall)		To reach 2nd quartile
	Controllable Costs	99.80%	106.20%	97.90%	95.70%	92.10%	95.56%		To achieve an actual spend within 5% of budget
	Net Income (2015& 16 - before swap/regulatory adjustments)	93.10%	114.70%	117.00%	107.90%	113.70%	117.61%		To achieve a net income within 10% of budget
	Regulatory Rate of Return (OEB measure)	8.43	8.64	9.1	8.89%	9.93%	NA (updated in the fall)		To achieve a ROE of greater than 8%
	Bad Debt	0.12%	0.06%	0.13%	0.05%	0.17%	0.11%		To achieve a bad debt percentage of less than .12% of total electrical bill
	Regulatory Compliance	Compliant	Compliant	Compliant	Compliant	Compliant	Compliant		To be compliant with all Regulatory oversight bodies including OEB, ESA, WSIB, MOL, etc.
Reliability Measures Achieve Continuous Improvement on all Reliability Measures	SAIDI (*Excludes Loss of Supply and Major Events)	1.69*	0.92*	1.79*	1.27*	1.95*	0.81*		To obtain an Index less than the 5 year rolling average (1.52)
	SAIFI (*Excludes Loss of Supply and Major Events)	1.92*	0.73*	1.78*	1.00*	1.63*	0.80*		To obtain an Index less than the 5 year rolling average (1.41)
	Momentary Interruptions (per Feeder)	C	NC	NC	C	NC	NC		Not to exceed 10 interruptions on any one feeder
Generation To Connect at least 500 kW of Renewable Generation within the next 4 years	kW Contracted	0	0	0	0	0	0		at least 500kW (within 2 years)
	kW Connected	30	30	30	30	30	30		at least 500kW (within 4 years)
Safety To Achieve WSIB Workwell Compliance	Number of Workplace Lost Time Injuries per Calendar Year	0	0	0	0	0	0		Target to equal 0
	OEB ESA Measures	C	C	C	C	C	N/A		Meet or exceed the OEB Scorecard targets including public safety, public awareness and 22/04 Compliance
	Number of JHSC Meetings per year	12	11	12	12	12	12		Monthly Meetings
	Number of "Safety Concerns" Reported per Calendar Year	25	10	72	60	33	27		Target to be greater than 50
	Number of Line Crew Inspections to be Completed by Operations Manager	89	81	98	83	93	109		Monthly Inspections
	Number of Line Crew Inspections to be Completed by VP Eng and Ops	12	12	12	12	6	14		Monthly Inspections
	Number of Line Crew Inspections to be Completed by CEO	4	4	4	3	11	4		Quarterly Inspections
	Number of Locator Inspections to be completed by Operations Manager	18	19	28	9	46	44		Monthly Inspections
	Number Meter Tech Inspections to be completed by Metering/Smart Grid Manager	12	N/A	N/A	N/A	N/A	12		Monthly Inspections
	Number of Engineering Field Inspections completed by Engineering Manager	4	4	9	8	0	4		Quarterly Inspections
	Number of Engineering Field Inspections completed by VP Eng and Ops	4	4	4	4	4	4		Quarterly Inspections
	Number of Office and Service Centre Inspections Completed	12	12	12	12	12	12		Monthly Inspections
	Lost time Injury Frequency (LTIF)	0	0	0	0	0	0		Target to equal 0
	Lost time Injury Severity (LTIS)	0	0	0	0	0	0		Target to equal 0
Customer Experience To Obtain at least 90% Customer Satisfaction Score	Billing Accuracy	99.98	99.95	99.99	99.99	99.99	99.9997		Target to be at least 98%
	# of Phone Calls	20,386	19,226	19,384	19,282	19,185	18,651		**Target to be determined after new website launch
	# of Customers on Paperless Billing	3,054	3,901	4,872	5,840	6,880	7,744		**Target to be determined after new website launch
	# of Customers Accessing Website (unique user visits)	19,706	22,230	27,764	32,951	13,147 (Oct-Dec)	43,412		**Target to be determined after new website launch
	First Contact Resolution	99.99	99.99	99.99	99.93	100	99.99		Target to be at least 98%
	Telephone Calls Answered on Time	83	88	88	99	91.48	90.42		Target to be at least 90%
	Telephone Call Abandon Rate	1.00	1.08	0.92	1.71	1.98	0.95		Target to be under 2%
	Written Responses to Enquiry	100	100	99.99	99.96	99.99	99.95		Target to be at least 98%
	Reconnection Performance Standard	100	100	100	100	100	100		Target to be at least 98%
	Customer Satisfaction	NA	90	NA	91	N/A	93		Target to be at least 90%
Human Resources To be a Canadian Small Business top 100 Employer	Staff Development Expenses	131,000	116,000	117,000 (2,665/employee)	$53,000 (1,223/employee)	$95,882 (2,421.25/employee)	$160,620 ($3788/employee)		To be at least $150,000 per year (roughly $3000 per employee)
	Short Term Absenteeism	3.61	2.97	3.64	4.38	4.29	4.65		To be less than 5 days per employee
	Grievances	0	0	3	0	1	0		To minimize grievances to less than 5 per contract term
	Employee Satisfaction Survey	2.87	NA	3.20	NA	3.06	3.06		To achieve a 3.0 on employee satisfaction
	Employee Engagement	74%	69%	52%	NA	68%	87%		To get each employee out to at least 1 Festival Hydro event
Community Involvement To be Known for and Publicly Recognized as a Leader in Community Support and Contribution	Media/Social Media Mentions		92%	92%	75%	83%	75%		One goodwill interaction in media/social media per month
	Social Investment		Paperless promos/donations - $2400, Community contributions - $20,346, Mobility summit/marketing - $13,359	Paperless promo - $3,240, Community contributions - $18,380	Community contributions - $20,000	Paperless promo - $5,000, Community contributions - $27,500	$29,715		Atleast $20K/year towards community initiatives
	Employee Community Involvement					NA			80% participation rate of employees who volunteered time with a community organization
	Employee Community Involvement					NA			50 volunteer hours donated by FHI employees
Enterprise Risk Assessment Mitigate Risks within Acceptable Tolerance Level	Enterprise Heat Map								Continuous mitigation of Top Enterprise Risks

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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Festival Hydro Inc.

Opinion

We have audited the financial statements of Festival Hydro Inc. (the Entity), which comprise:

- the statement of financial position as at December 31, 2022
- the statement of comprehensive income for the year then ended
- statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the **"Auditor's 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 International Financial Reporting Standards (IFRS), 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.

Auditor's 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.

KPMG

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 auditor's 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 auditor's 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.

Chartered Professional Accountants, Licensed Public Accountants

London, Canada
April xx, 2023

Financial Statements of

Festival Hydro Inc.

Year ended December 31, 2022

Festival Hydro Inc.

Statement of Financial Position
December 31, 2022, with comparative information for December 31, 2021

	Notes	2022	2021
Assets			
Accounts receivable	6, 22	$ 8,079,655	$ 8,124,901
Unbilled revenue	22	4,783,498	5,230,771
Inventories	7	177,526	163,443
Prepaid expenses		230,441	357,282
Income tax receivable		511,562	356,057
Due from corporations under common control	20	122,147	332,803
Total current assets		**13,904,829**	**14,565,257**
Non-current assets			
Property, plant and equipment	8	58,854,033	57,113,909
Intangible assets and goodwill	9	1,806,282	1,734,841
Unrealized gain on interest rate swap	22	784,886	-
Total non-current assets		**61,445,201**	**58,848,750**
Total assets		**75,350,030**	**73,414,007**
Regulatory balances	13	7,503,962	4,527,854
Total assets and regulatory balances		**$ 82,853,992**	**$ 77,941,861**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Financial Position

December 31, 2022, with comparative information for December 31, 2021

	Notes	2022	2021
Liabilities and Equity			
Bank indebtedness	5	$ 3,740,695	$ 15,768
Accounts payable and accrued liabilities		8,658,017	9,902,642
Deferred revenue		273,286	194,274
Income tax payable		-	-
Dividend payable	15, 21	248,269	500,556
Current portion of long-term debt	14, 22	16,328,464	16,307,717
Customer deposits	11	1,016,175	1,169,542
Due to the Corporation of the City of Stratford	20	624,251	625,460
Total current liabilities		**30,889,157**	**28,715,959**
Non-current liabilities			
Deferred revenue		2,641,341	2,453,813
Customer deposits	11	980,367	594,311
Deferred tax liabilities	10	2,381,370	1,308,987
Employee future benefits	12	1,009,878	1,361,643
Unrealized loss on interest rate swap	22	-	938,948
Long-term debt	14, 22	9,812,012	10,540,477
Total non-current liabilities		16,824,968	17,198,179
Total liabilities		**47,714,125**	**45,914,138**
Share capital	15	15,568,388	15,568,388
Accumulated other comprehensive loss		(54,479)	(357,737)
Retained earnings		18,525,126	15,085,495
Total equity		**34,039,035**	**30,296,146**
Total liabilities and equity		81,753,160	76,210,284
Regulatory balances	13	1,100,832	1,731,577
Total liabilities, equity and regulatory balances		**82,853,992**	**77,941,861**

Commitments and contingencies (note 23)
Guarantee (note 24)

The accompanying notes are an integral part of these financial statements.

On behalf of the Board:

Director

Director

Festival Hydro Inc.

Statement of Comprehensive Income

Year ended December 31, 2022, with comparative information for 2021

	Notes	2022	2021
Revenues			
Sale of energy	16	$ 55,589,074	$ 59,559,802
Distribution revenue	16	12,174,085	11,582,698
Other income	17	1,118,521	1,195,884
		68,881,680	**72,338,384**
Cost of power purchased		58,141,145	60,698,856
Operating expenses	18	6,759,045	6,014,814
Depreciation and amortization	8,9	2,505,726	2,412,000
		67,405,916	**69,125,670**
Income from operating activities		**1,475,764**	**3,212,714**
Finance income	19	1,747,174	664,530
Finance costs	19	(1,574,778)	(1,604,249)
Income before income taxes		**1,648,160**	**2,272,995**
Income tax expense	10	1,096,421	917,289
Net income		**551,739**	**1,355,706**
Net movement in regulatory balances:			
Net movement in regulatory balances	13	2,534,470	1,168,069
Income tax	10,13	992,021	590,859
Net income and net movement in regulatory balances		**4,078,230**	**3,114,634**
Other comprehensive income (loss)			
Items that will not be reclassified to profit and loss:			
Remeasurements of employee future benefits	12	303,258	80,606
Tax on remeasurements	10	(80,363)	(21,361)
Net movement in regulatory balances	13	80,363	21,361
Other comprehensive loss		**303,258**	**80,606**
Total comprehensive income		**$ 4,381,488**	**$ 3,195,240**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Changes in Equity

Year ended December 31, 2022, with comparative information for December 31, 2021

	Share capital	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2021	**$15,568,388**	**$12,861,747**	**$ (438,343)**	**$ 27,991,792**
Net income after net movement in regulatory balances	–	3,114,634	–	3,114,634
Other comprehensive loss	–	–	80,606	80,606
Dividends, paid or payable	–	(890,886)	–	(890,886)
Balance at December 31, 2021	**$15,568,388**	**$15,085,495**	**$ (357,737)**	**$ 30,296,146**
Balance at January 1, 2022	**$15,568,388**	**$15,085,495**	**$ (357,737)**	**$ 30,296,146**
Net income after net movement in regulatory balances	–	4,078,230	–	4,078,230
Other comprehensive loss	–	–	303,258	303,258
Dividends, paid or payable	–	(638,599)	–	(638,599)
Balance at December 31, 2022	**$15,568,388**	**$18,525,126**	**$ (54,479)**	**$ 34,039,035**

The accompanying notes are an integral part of these financial statements.

Festival Hydro Inc.

Statement of Cash Flows

Year ended December 31, 2022, with comparative information for December 31, 2021

Cash provided by (used in)	Notes	2022	2021
Operating activities			
Net income after net movement in regulatory balances		$4,078,230	$3,114,634
Adjustments for			
Depreciation - property, plant and equipment	8	2,243,817	2,113,654
Amortization - intangible assets	9	261,909	298,348
Amortization of deferred revenue		(76,869)	(60,633)
Employee future benefits		(48,508)	(50,668)
Net finance costs	19	(172,396)	939,718
Income tax expense	10	1,096,421	917,289
		7,382,604	7,272,342
Changes in non-cash operating working capital			
Accounts receivable		45,246	(1,104,430)
Unbilled revenue		447,273	1,140,450
Inventories		(14,083)	9,169
Prepaid expenses		126,841	32,564
Accounts payable and accrued liabilities		(1,244,625)	1,314,930
Due from related parties		210,656	294,268
Due from the City of Stratford		(1,209)	(6,477)
Dividends declared		(252,287)	385,345
Customer deposits		232,689	269,859
		(449,499)	2,335,678
Regulatory balances	13	(3,526,490)	(1,758,928)
Interest paid	19	(1,574,778)	(1,604,248)
Interest received		23,340	18,445
Income tax paid, net of refund		(5,476)	(888,101)
Net cash from operating activities		**1,849,701**	**5,375,188**
Investing activities			
Purchase of property, plant and equipment	8	(3,983,941)	(3,780,502)
Purchase of intangible assets	9	(333,350)	(77,945)
Net cash used in investing activities		(4,317,291)	(3,858,447)
Financing activities			
Contributions received from customers, net of repayments		341,267	479,666
Dividends	15	(890,886)	(505,541)
Proceeds from long-term debt		-	900,000
Repayment of long-term debt		(707,718)	(1,429,445)
Net cash used in financing activities		(1,257,337)	(555,320)
Decrease in bank indebtedness during the year		(3,724,927)	961,421
Bank indebtedness, beginning of the year		(15,768)	(977,189)
Bank indebtedness, end of the year		**$ (3,740,695)**	**$ (15,768)**

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

Festival Hydro Inc. (the "Corporation") is a wholly owned subsidiary of the City of Stratford. The Corporation was incorporated on July 11, 2000 under the Business Corporations Act (Ontario) pursuant to Section 142 of the Electricity Act Laws of the Province of Ontario, Canada. The address of the Corporation's registered office is 187 Erie Street, Stratford, Ontario, Canada.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the City of Stratford and the towns of Brussels, Dashwood, Hensall, Seaforth, St. Marys and Zurich, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the Ontario Energy Board and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2022.

2. Basis of preparation:

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). These financial statements were approved by the Board of Directors on April 27, 2023.

(b) Basis of measurement

The financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

(d) Use of estimates and judgements

Information about judgements made in applying accounting policies that have an effect on the amounts recognized in the financial statements is included in the following notes:

Note 3(l)	Determination of the performance obligation for contribution and the related amortization period
Note 3(m)	Whether an arrangement contains a lease
Note 6	Estimate for impairment for uncollected amounts, based on the lifetime expected credit losses
Note 8	Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment.
Note 9	Intangible assets: useful lives and goodwill impairment testing.
Note 12	Measurement of the defined benefit obligation – actuarial assumptions
Note 23	Recognition and measurement of commitments and contingencies.

2. Basis of preparation (continued)

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board, under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, amongst other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill certain classes of customers for the debt retirement charges. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

(f) Rate setting

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a "Cost of Service" ("COS") rate application with the OEB where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each class. The COS application is reviewed by the OEB and interveners on record. Rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years, the Corporation has chosen to file a Price Cap Incentive Rate Mechanism ("IRM") application. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

On May 27, 2014, the Corporation filed its 2015 Cost of Service application. The OEB issued its final Decision and Order dated June 5, 2015. The decision allows for a total service revenue requirement of $11,210,828 based on a total rate base of $61,778,759. The deemed debt portion of the rate base (60%) at $27,067,256 earns a weighted average rate of 4.05%. The deemed equity portion of the rate base (40%) at $24,711,504 earns a deemed return on equity of 9.30%. The rates were effective May 1, 2015 with an implementation date of June 1, 2015.

2. Basis of preparation (continued)

(f) Rate setting (continued)

Distribution revenue (continued)

Festival filed its 2021 IRM application for distribution rates and was approved new rates by the OEB effective January 1, 2021. The Corporation's approved adjustment to distribution rates was 1.90%, as a result of an OEB approved inflation factor of 2.20%, less a stretch factor of 0.30% determined by the relative efficiency of the Corporation. The application included the approval of rate riders for the disposition of certain deferral and variance balances.

Festival filed its 2022 IRM application for distribution rates and was approved new rates by the OEB effective January 1, 2022. The Corporation's approved adjustment to distribution rates was 3.00%, as a result of an OEB approved inflation factor of 3.30%, less a stretch factor of 0.30% determined by the relative efficiency of the Corporation. The application included the approval of rate riders for the disposition of certain deferral and variance balances.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity and the global adjustment. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently for both years presented in these financial statements in accordance with IFRS.

(a) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income (“OCI”). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. Significant accounting policies (continue):

(a) Regulatory balances (continued)

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts. On the statement of cash flows, cash and cash equivalents includes bank overdrafts (revolving credit facility) that are repayable on demand and form an integral part of the Corporation's cash management.

(c) Financial instruments

All financial assets are classified as loans and receivables, except for marketable securities which are classified as available for sale and derivatives which are measured as fair value through profit and loss. All financial liabilities are classified as other financial liabilities. These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs.

Loans and receivables and other financial liabilities are subsequently measured at amortized cost using the effective interest method less any impairment for the financial assets.

Available for sale financial assets are subsequently measured at fair value, within the changes therein recognized in other comprehensive income until the assets are sold. Upon sale of an available for sale asset, the Corporation has elected to record the accumulated unrealized change in value of the asset as a transfer through other comprehensive income into profit and loss.

The Corporation holds derivative financial instruments to manage its interest rate risk exposures. Derivatives are initially measured at fair value; any directly attributable transaction costs are recognized in profit or loss as incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein, are recognized in the statement of comprehensive income. Hedge accounting has not been used in the preparation of these financial statements.

(d) Inventories

Inventories are stated at lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis, net of a provision for obsolescence, as applicable. The Corporation classifies all major construction related component of its electricity distribution infrastructure to property, plant and equipment.

(e) Property, plant and equipment ("PP&E")

Items of property, plant and equipment used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, or, where the item is transferred from customers, its fair value, less accumulated depreciation and accumulated impairment losses. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

3. Significant accounting policies (continued):

(e) Property, plant and equipment ("PP&E")

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour and any other costs directly attributable to bringing the asset to a working condition for its intended use. Borrowing costs on qualifying assets are capitalized as part of the cost of the asset and are based on the Corporation's cost of borrowing. For construction projects of less than one year in length, borrowing costs are not capitalized unless specific identifiable loans are acquired for the express purpose of financing a specific construction activity.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing part of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. The carrying amount of the replaced part is derecognized.

The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred. Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not amortized until the project is complete and in service.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives. Depreciation methods, useful lives and residual values are reviewed at each reporting date and adjusted if appropriate. The estimated useful lives for the current and comparative years are as follows:

Buildings	10 to 60 years
Distribution substation equipment	30 to 60 years
Distribution system equipment	30 to 60 years
Transformers	35 to 40 years
Meters	15 to 40 years
Other capital assets	4 to 20 years

Other capital assets include vehicles, office and computer equipment.

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized within other income in the statement of comprehensive income.

3. Significant accounting policies (continued):

(f) Intangible assets

Intangible assets include goodwill, computer software and capital contributions paid under capital cost recovery agreements ("CCRAs").

(i) Goodwill

Goodwill represents the excess of cost over fair value of net assets which arose upon amalgamation of the former electrical distribution entities. Goodwill is measured at cost less accumulated impairment losses.

(ii) Computer software

Computer software acquired prior to January 1, 2014, is measured at deemed cost less accumulated depreciation. All other software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

(iii) Capital contributions paid under capital cost recovery agreements

Capital contributions paid under CCRAs are measured at cost less accumulated amortization and accumulated impairment losses.

(iv) Amortization

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. The estimated useful lives for the current and comparative years are:

Computer software	5 years
CCRAs	15 to 25 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted if appropriate.

(g) Impairment

(i) Financial assets measured at amortized cost

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

3. Significant accounting policies (continued):

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than regulatory assets, inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill, the recoverable amount is estimated as at December 31 of each year.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The Corporation has determined that it has one cash generating unit. The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to cash-generating units that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Employee benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“Fund”). The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

3. Significant accounting policies (continued):

(i) Pension plan (continued)

OMERS is a defined benefit plan, however, as the plan assets and pension obligations are not segregated in separate accounts for each member entity, sufficient information is not available to enable the Corporation to directly account for the plan. As such, the plan has been accounted for as a defined contribution plan. The contribution payable is recognized as an employee benefit expense in the statement of comprehensive income in the period in which the service was rendered by the employee, since it is not practicable to determine the Corporation's portion of person obligations of the fair value of plan assets.

(ii) Employee future benefits, other than pension

The Corporation has an unfunded benefit plan providing post-employment benefits (other than pension) to its employees. The Corporation provides its retired employees (20 years service; less than age 65) with life insurance and medical benefits beyond those provided by government sponsored plans. Life insurance is provided for current retirees including those over age 65.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses, are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(j) Deferred revenue and assets transferred from customers

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded under current liabilities as customer deposits. Once the distribution system asset is completed or modified, as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction. The contributions in aid of construction account, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is reported as deferred revenue, and is amortized to other income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(k) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts, calculated using OEB prescribed interest rates, and owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability. Annually, accrued interest is applied directly to the customers' accounts.

3. Significant accounting policies (continued):

(k) Customer deposits (continued)

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when the Corporation no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

(l) Revenue Recognition

(i) Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

(ii) Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

3. Significant accounting policies (continued):

(l) Revenue Recognition (continued)

(ii) Other revenue

Revenue earned from the provision of services is recognized as the service is rendered. Government grants and the related performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(m) Leased assets

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

3. Significant accounting policies (continued):

(n) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on customer deposits, the demand notes payable, revolving credit facility and long-term borrowings.

Changes in the fair value of interest rate swap agreements are recorded either in finance income, or costs, depending on whether an unrealized gain or loss is required.

(o) Income taxes

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to other comprehensive income or items recognized directly in equity, in which case, it is recognized in accumulated comprehensive income or retained earnings, respectively.

Current tax is the tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit or debt balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of comprehensive income.

3. Significant accounting policies (continued):

(o) Income taxes (continued)

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of comprehensive income.

4. Standards issued but not yet adopted:

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. These standards or amendments relate to the measurement and disclosure of financial assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

i. Classification of Liabilities as Current or Non-current (Amendments to IAS 1)
ii. Definition of Accounting Estimates (Amendments to IAS 8)
iii. Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)

i. Classification of Liabilities as Current or Non-current (Amendments to IAS 1):

On January 23, 2020, the IASB issued amendments to IAS 1 Presentation of Financial Statements, to clarify the classification of liabilities as current or non-current. On July 15, 2020 the IASB issued an amendment to defer the effective date by one year. The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

For the purposes of non-current classification, the amendments removed the requirement for a right to defer settlement or roll over of a liability for at least twelve months to be unconditional. Instead, such a right must have substance and exist at the end of the reporting period. The amendments also clarify how a company classifies a liability that includes a counterparty conversion option.

The amendments state that settlement of a liability includes transferring a company's own equity instruments to the counterparty, and when classifying liabilities as current or non-current, a company can ignore only those conversion options that are recognized as equity.

The Corporation intends to adopt this standard in its financial statements for the annual period beginning January 1, 2023. The extent of the impact of adoption of the standard has not yet been determined

ii. Definition of Accounting Estimates (Amendments to IAS 8):

On February 12, 2021, the IASB issued Definition of Accounting Estimates (Amendments to IAS 8). The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

4. Standards issued but not yet adopted (continued):

The amendments introduce a new definition for accounting estimates, clarifying that they are monetary amounts in the financial statements that are subject to measurement uncertainty. The amendments also clarify the relationship between accounting policies and accounting estimates by specifying that a company develops an accounting estimate to achieve the objective set out by an accounting policy.

The Company intends to adopt this standard in its financial statements for the annual period beginning January 1, 2023. The extent of the impact of adoption of the standard has not yet been determined.

iii. Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2):

On February 12, 2021, the IASB issued Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2 Making Materiality Judgements). The amendments are effective for annual periods beginning on or after January 1, 2023. Early adoption is permitted.

The amendments help companies provide useful accounting policy disclosures. The key amendments include:

– requiring companies to disclose their material accounting policies rather than their significant accounting policies;

– clarifying that accounting policies related to immaterial transactions, other events or conditions are themselves immaterial and as such need not be disclosed; and

– clarifying that not all accounting policies that relate to material transactions, other events or conditions are themselves material to a company’s financial statements.

The Company intends to adopt this standard in its financial statements for the annual period beginning January 1, 2023. The Company does not expect this standard to have a material impact on the financial statements.

5. Bank indebtedness:

	2022	2021
Cash	$ 660	$ 1,660
Revolving credit facility	(3,741,355)	(17,428)
Bank indebtedness	**$ (3,740,695)**	**$ (15,768)**

6. Accounts receivable:

	2022	2021
Energy, water and sewer	$ 6,523,810	$ 6,223,521
Other	1,555,845	1,901,380
Total	**$ 8,079,655**	**$ 8,124,901**

Included in accounts receivable is $1,230,333 (2021 - $1,193,417) of customer receivables for water consumption and sewer ("water & sewer") that the Corporation bills and collects on behalf of the City of Stratford and the Town of St. Marys. As the Corporation does not assume liability for collection of these amounts, any amount related to City of Stratford and Town of St. Marys water & sewer charges that are determined to be uncollectible are charged to the City of Stratford and Town of St. Marys, respectively. At year end, there is nil (2021 - nil) included in the provision for impairment for uncollectable amounts relating to water and sewer.

7. Inventories:

The amount of inventories consumed by the Corporation and recognized as an expense during 2022 was $149,137 (2021 - $166,873). During 2022, an amount of nil (2021 – nil) was recorded as an expense for the write-down of obsolete or damaged inventory to net realizable value.

8. Property, plant and equipment:

a) Cost or deemed cost

	Land and buildings	Distribution substation equipment	Other distribution system equipment	Transformer station	Total
Balance at January 1, 2021	$2,663,162	$47,579,167	$2,810,734	$14,049,010	$67,102,073
Additions	477,555	2,698,194	326,676	143,417	3,645,842
Transfers	-	-	134,660	-	134,660
Disposals/retirements	(6,795)	(230,606)	(155,736)	-	(393,137)
Balance at December 31, 2021	**$3,133,922**	**$ 50,046,755**	**$ 3,116,334**	**$ 14,192,427**	**$ 70,489,438**
Balance at January 1, 2022	$3,133,922	$50,046,755	$3,116,334	$14,192,427	$70,489,438
Additions	357,228	3,022,647	281,971	86,263	$3,748,109
Transfers	-	-	235,832	-	$235,832
Disposals/retirements	(27,578)	(297,300)	(375,808)	-	($700,686)
Balance at December 31, 2022	**$3,463,572**	**$52,772,102**	**$3,258,329**	**$14,278,690**	**$73,772,693**

b) Accumulated depreciation

	Land and buildings	Distribution substation equipment	Other distribution system equipment	Transformer station	Total
Balance at January 1, 2021	$ 337,380	$ 7,977,726	$ 1,119,839	$ 2,220,066	$ 11,655,011
Depreciation	96,716	1,413,877	268,888	334,173	2,113,654
Disposals/retirements	(6,795)	(230,605)	(155,736)	-	(393,136)
Balance at December 31, 2021	$ 427,301	$ 9,160,998	$ 1,232,991	$ 2,554,239	$ 13,375,529
Balance at January 1, 2022	$427,301	$9,160,998	$1,232,991	$2,554,239	$13,375,529
Depreciation	120,660	1,491,865	285,635	345,657	$2,243,817
Disposals/retirements	(27,578)	(297,300)	(375,808)	-	($700,686)
Balance at December 31, 2022	$520,383	$10,355,563	$1,142,818	$2,899,896	$14,918,660

c) Carrying amounts

	Land and buildings	Distribution substation equipment	Other distribution system equipment	Transformer station	Total
December 31, 2021	$2,706,621	$40,885,757	$1,883,343	$11,638,188	$57,113,909
December 31, 2022	$2,943,189	$42,416,539	$2,115,511	$11,378,794	$58,854,033

d) Borrowing costs

During the year, no borrowing costs (2021 – nil) were capitalized as part of the cost of property, plant and equipment.

9. Intangible assets and goodwill:

a) Cost or deemed cost

	Goodwill	Computer software	Land Rights	CCRA's	Total
Balance at January 1, 2021	$ 515,359	$ 1,593,915	$ 3,150	$ 966,935	$ 3,079,359
Additions	-	77,945	-	-	77,945
Disposals	-	(252,888)	-	-	(252,888)
Balance at December 31, 2021	**$ 515,359**	**$ 1,418,972**	**$ 3,150**	**$ 966,935**	**$ 2,904,416**
Balance at January 1, 2022	$515,359	$ 1,418,972	$ 3,150	$ 966,935	$ 2,904,416
Additions	-	111,889	-	-	111,889
Work in Progress	-	221,461	-	-	221,461
Disposals	-	(312,506)	-	-	(312,506)
Balance at December 31, 2022	**$ 515,359**	**$ 1,439,816**	**$ 3,150**	**$ 966,935**	**$ 2,925,260**

b) Accumulated amortization

	Goodwill	Computer software	Land Rights	CCRA's	Total
Balance at January 1, 2021	**$ -**	**$ 750,096**	**$ -**	**$ 374,019**	**$ 1,124,115**
Amortization	**-**	243,875	**-**	54,473	298,348
Disposals	**-**	(252,888)	**-**	-	(252,888)
Balance at December 31, 2021	$ -	**$ 741,083**	$ -	**$ 428,492**	**$ 1,169,575**
Balance at January 1, 2022	$ -	$ 741,083	$ -	$ 428,492	$ 1,169,575
Amortization	-	207,436	-	54,473	261,909
Disposals	-	(312,506)	-	-	(312,506)
Balance at December 31, 2022	$ -	**$ 636,013**	$ -	**$ 428,492**	**$ 1,118,978**

c) Carrying amounts

	Goodwill	Computer software	Land Rights	CCRA's	Total
December 31, 2021	$ 515,359	$ 677,889	$ 3,150	$ 538,443	$ 1,734,841
December 31, 2022	$ 515,359	$ 803,803	$ 3,150	$ 483,970	$ 1,806,282

d) Goodwill impairment

Management has determined that the Corporation's rate regulated operations are one cash generating unit. Therefore, the goodwill was allocated to the Corporation as a whole. The annual impairment test is based on the Corporation's value in use. Value in use was determined by discounting the future cash flows of the Corporation and was based on the following key assumptions:

9. Intangible assets and goodwill:

d) Goodwill impairment (continued)

A detailed valuation of the Corporation was undertaken during 2022 based on financial results of the Corporation as at December 31, 2022. Cash flows were projected based on actual operating results and the cost of capital and rate of return as approved in the 2015 Cost of Service application. A discounted cash flow model was utilized based on free cash flows for 20 years, followed by a terminal value calculated based on a steady-state cash flow, with the terminal value within range of market-based terminal multiples. The recoverable amount of the Corporation was determined to be greater than the carrying value of goodwill and no impairment was recorded as at December 31, 2022 or December 31, 2021.

10. Income taxes:

Income tax expense	**2022**	**2021**
Current tax expense:		
Current year	$ 160,945	$ 322,507
Prior year	(56,545)	3,923
Total current tax expense	104,400	326,430
Deferred tax expense:		
Change in recognized deductible temporary differences	992,021	590,859
Total current and deferred income tax in profit or loss, before movement of regulatory balance	1,096,421	917,289
Other comprehensive income:		
Employee future benefits	80,363	(21,361)
Total current and deferred tax, before movement in regulatory balances	1,176,784	938,650
Net movement in regulatory balances	(1,072,384)	(612,220)
Income tax expense recognized in statement of comprehensive Income	**$104,400**	**$326,430**

Reconciliation of effective tax rate	**2022**	**2021**
Income before taxes	$4,486,834	$3,538,670
Canada and Ontario statutory income tax rates	26.5%	26.5%
Expected tax provision on income tax at statutory rates	1,189,011	937,748
Increase (decrease) in income tax resulting from:		
Permanent differences	2,212	1,420
Recognized deductible temporary difference due from customers	(1,072,384)	(612,220)
Other	(14,439)	(518)
Income tax expense	**$ 104,400**	**$ 326,430**

10. Income taxes (continued):

	2022	2021
Deferred tax assets (liabilities):		
Property, plant, equipment and intangible assets	($2,488,634)	($1,968,063)
Employee future benefits	267,618	360,835
Other	(160,354)	298,241
	($2,381,370)	**($1,308,987)**

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers as well as construction deposits. These customer deposits bear interest at the OEB's prescribed interest rate, which is the Bank of Canada's prime business rate less 2%.

Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service. Due to the demand nature of these deposits, they are classified as current liabilities.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to deferred revenue.

Customer deposits comprise:

	2022	2021
Electricity deposits	$ 957,164	$1,061,051
Construction deposits	1,039,378	702,802
Total customer deposits	**$1,996,542**	**$1,763,853**
Consisting of:		
Short-term	$ 1,016,175	$ 1,169,542
Long-term	980,367	594,311

12. Employee future benefits:

(a) Employee future benefits, other than pension

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. These benefits are provided through a group defined benefit plan. The Corporation has reflected its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these financial statements. The accrued benefit liability and the corresponding expense were based on results and assumptions determined by actuarial valuation as at December 31, 2022.

12. Employee future benefits (continued):

Changes in the present value of the defined benefit unfunded obligation and the accrued benefit liability:

	2022	2021
Defined benefit obligation, beginning of year	$ 1,361,643	$ 1,492,917
Included in profit or loss:		
Current service cost	36,217	39,189
Interest cost	38,994	37,165
	75,211	76,354
Included in OCI:		
Actuarial (gains) losses arising from changes in financial assumptions	(303,258)	(80,606)
Benefits paid during the year	(123,718)	(127,022)
Defined benefit obligation, end of year	**$1,009,878**	**$1,361,643**

The significant actuarial assumptions used in the valuation are as follows:

	2022	2021
Discount rate	5.05%	3.00%
Rate of compensation increase	3.30%	2.50%
Initial health care cost trend rate	4.70%	4.70%
Initial dental cost trend rate	4.90%	4.90%
Year that rate reaches the rate it is assumed to be	2040	2040
Cost trend rate declines to	4.00%	4.00%

Significant actuarial assumptions for benefit obligation measurement purposes are the discount rate and assumed medical and dental cost trend rates. The sensitivity analysis below has been determined based on reasonably possible changes in the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely these changes in assumptions would occur in isolation from each other. The approximate effect on the accrued benefit obligation of the entire plan and the estimated net benefit expense of the entire plan if the health care trend rate assumption was increased or decreased by 1%, and all other assumptions were held constant, is as follows:

	2022	2021
Benefit Obligation, end of year	$1,009,878	$1,361,644
1% increase in health care trend rate	26,900	50,156
1% decrease in health care trend rate	(24,300)	(44,744)
1% increase in discount rate	(96,500)	(167,544)
1% decrease in discount rate	119,000	215,456

(b) Pension plan

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System. The plan is a multi-employer, contributory defined benefit pension plan. In 2022, the Corporation made employer contributions of $365,116 to OMERS (2021 - $353,752). The Corporation's net benefit expense has been allocated as follows:

- $138,744 (2021 - $134,426) capitalized as part of PP&E
- $186,209 (2021 - $180,413) charged to operating expenses
- $40,163 (2021 - $38,913) charged to CDM and billable work

12. Employee future benefits (continued):

(b) Pension plan (continued)

As at December 31, 2022, OMERS states that their plan was 97% funded (2021 – 97%). OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. The Corporation's contributions represent less than 1% of the total annual contributions to the OMERS plan.

13. Regulatory assets and liabilities:

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

In the tables below, the "Additions" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts collected through rate riders or transactions reversing an existing regulatory balance. The "Other movements" column consists of reclassification between the regulatory debit and credit balances. For the years ended December 31, 2022 and 2021, the Corporation did not record any impairments related to regulatory debit balances.

	January 1, 2022	Additions	Recovery/ reversal	Other Movements	December 31, 2021	Notes
Regulatory deferral account debit balances						
Settlement (Group 1) variances	$ 2,939,939	$ 386,141	$ (313,926)	$ 2,075,470	$ 5,087,624	(1)
Stranded meters	2,292	21	-	-	2,313	(2)
LRAM	268,628	(244,237)	256	-	24,646	(1)
Deferred Taxes	1,308,987	1,072,383	-	-	2,381,370	(4)
Rate application costs	8,008	-	-	-	8,008	(3)
	$ 4,527,854	**$1,214,308**	**$ (313,670)**	**$ 2,075,470**	**$ 7,503,962**	

	January 1, 2021	Additions	Recovery/ reversal	Other Movements	December 31, 2021	Notes
Regulatory deferral account debit balances						
Settlement (Group 1) variances	$ 1,605,348	$ 1,538,071	$ (203,135)	$ (345)	$ 2,939,939	(1)
Stranded meters	2,286	6	-	-	2,292	(2)
LRAM	494,049	(219,691)	(5,730)	-	268,628	(1)
Deferred Taxes	696,766	612,221	-	-	1,308,987	(4)
Rate application costs	8,008	-	-	-	8,008	(3)
	$ 2,806,457	**$1,930,607**	**$ (208,865)**	**$(345)**	**$ 4,527,854**	

13. Regulatory assets and liabilities (continued):

	January 1, 2022	Additions	Recovery/ reversal	Other Movements	December 31, 2022	Notes
Regulatory deferral account credit balances						
Settlement (Group 1) variances	$ (1,286,576)	2,500,939	$ 313,670	$ (2,075,470)	(547,437)	(1)
IFRS transition adjustments	(10,783)	-	-	-	(10,783)	(5)
PILS	(434,218)	(108,394)	-	-	(542,612)	
	$ (1,731,577)	**$ 2,392,545**	**$ 313,670**	**$ (2,075,470)**	**$ (1,100,832)**	

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	January 1, 2021	Additions	Recovery/ reversal	Other Movements	December 31, 2021	Notes
Regulatory deferral account credit balances						
Settlement (Group 1) variances	$ (1,507,500)	11,714	$ 208,865	$ 345	(1,286,576)	(1)
IFRS transition adjustments	(10,783)	-	-	-	(10,783)	(5)
PILS	(272,186)	(162,032)	-	-	(434,218)	
	$ (1,790,469)	**$ (150,318)**	**$ 208,865**	**$ 345**	**$ (1,731,577)**	

1) The changes in settlement (Group 1) and LRAM balances outstanding from December 31, 2021 were approved for disposition as part of the 2022 IRM application with rates effective January 1, 2022 to be collected over a 12-month period.

2) As part of the 2015 COS application, the OEB approved the disposition of stranded meters through a rate rider effective May 1, 2015 (implemented June 1, 2015) with recovery over a 7-month period ending December 31, 2015. Since the residual balance is not material, it will remain in place until the next COS application.

3) The 2015 COS rate application costs were approved for recovery by the OEB and have been amortized over a forty-three-month period ending December 31, 2019.

4) Disposition is not requested for the deferred tax balance as it is being reversed through timing differences in the recognition of deferred tax assets. No carrying charges are calculated on this balance.

5) As part of the 2015 COS application, the OEB approved the disposition of the account 1575/76 IFRS transition account balance used to record the difference arising on adoption of new asset useful lives and overhead rates and write off of end-of-life assets. These account balances were included as a rate rider effective May 1, 2015 (implemented June 1, 2015) and were recovered over a 7-month period ended December 31, 2015. Since the residual balance is not material, it will remain in place until the next COS application.

Carrying charges are applied to all regulatory account balances at the OEB prescribed interest rates, with the exception of the deferred tax assets on which no carrying charges are applied.

As part of the Corporation's 2022 IRM application, the change in debit and credit balance settlement (Group 1) variance accounts occurring during fiscal 2021 were approved as part of 2022 distribution rates for recovery over a 12-month period commencing January 1, 2022. As such, the risk associated with the recovery of variance accounts is limited to the incremental value of non-settlement variances arising since 2021.

14. Long-term debt:

Long-term debt consists of the following:

	2022	2021
Royal Bank revolving term loan, bearing interest at 2.93%, plus a stamping fee of 0.42%, payable in monthly principal instalments of approximately $35,000 plus interest, increasing by $1,000 yearly until maturity on May 31, 2038, secured by a general security agreement.	9,875,000	10,366,000
Royal Bank loan, bearing interest at 2.62%, payable in monthly principal instalments of $19,768, maturing November 25, 2025, secured by a general security agreement.	665,476	882,194
Notes payable to shareholder, bearing interest at 7.25% per annum, with interest payments only, due on demand, unsecured.	15,600,000	15,600,000
	26,140,476	**26,848,194**
Less: current portion	16,328,464	16,307,717
Long-term debt	**$9,812,012**	**$10,540,477**

Interest rate swaps

The Corporation entered into an interest rate swap agreement on a notional principal of $14,000,000 effective May 31, 2013, which matures May 31, 2038. The swap is a receive-variable, pay-fixed swap with the Royal Bank. This agreement has effectively converted variable interest rates to an effective fixed interest rate of 2.93% plus stamping fee of 0.42% on the Royal Bank revolving term loan. The stamping fee is subject to change every 10 years, with the first maturity being May 31, 2023.

Additionally, the Corporation entered into an interest rate swap agreement on a notional principal of $5,000,000. The Corporation has not yet made any draws on this available credit and is not required to do so until the effective date of December 31, 2024. This agreement has effectively converted variable interest rates to an effective fixed interest rate of 2.51% plus stamping fee of 0.42% on the Royal Bank revolving term loan.

The Corporation has determined these swaps do not meet the standard to apply hedge accounting. Since the standard is not met, the interest rate swap contracts have been recorded at their fair value at December 31, 2022 with the combined unrealized gain for the year of $1,723,834 (2021 – $646,085) recorded as finance cost in the statement of comprehensive income.

14. Long-term debt continued:

Reconciliation of movements of liabilities to cash flows arising from financing activities:

	Current and long-term debt	Dividends payable	Retained earnings	Total (financing cash flows)
Balance at January 1, 2022	$ 26,848,194	$ 500,556	$ 15,085,495	
Dividends paid	-	(500,556)	(390,330)	$ (890,886)
Proceeds from long-term debt	-	-	-	-
Repayments of long-term debt	(707,718)	-	-	(707,718)
Total changes from financing cash flows	**$ (707,718)**	**$ (500,556)**	**$ (390,330)**	**$ (1,598,604)**
Dividend declared but not paid	-	248,269	(248,269)	-
Net income after net movements in regulatory balances	-	-	4,078,230	-
Balance at December 31, 2022	$ 26,140,476	$ 248,269	$ 18,525,126	$ -

15. Share capital:

	2022	2021
Authorized:		
Unlimited Class A special shares, non-cumulative, 5.0%		
Unlimited Class B special shares		
Unlimited Common shares		
Issued:		
6,100 Class A special shares	$ 6,100,000	$ 6,100,000
6,995 Common shares	9,468,388	9,468,388
	$ 15,568,388	**$15,568,388**

Dividends paid on the 6,100 class A special shares during the year totalled $152,500 (2021 - $152,500). Dividends paid on the 6,995 common shares during the year totalled $486,099 (2021 - $738,386). A common share dividend was declared on December 15, 2022 and is payable on all common shares on record at December 31, 2021, with the dividend to be paid in 2023. The dividend amount payable at December 31, 2022 is $248,269 (2021 - $500,556).

16. Revenue from Contracts with Customer:

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. Sources of revenue are as documented in the table below.

	2022 Sale of Energy	2022 Distribution Revenue	2021 Sale of Energy	2021 Distribution Revenue
Residential	$ 17,226,469	$ 6,928,900	$ 16,035,245	$ 6,695,809
Commercial	35,806,876	4,757,459	39,685,538	4,553,668
Large Users	2,762,863	314,993	2,653,924	321,241
Other	(207,133)	172,733	1,185,095	11,980
	$ 55,589,074	**$ 12,174,085**	**$ 59,559,802**	**$ 11,582,698**

17. Other income:

	2022	2021
Collection, late payment and other service charges	$ 124,331	$ 187,699
Pole attachment and other rental income	108,836	128,767
Miscellaneous	853,362	852,693
Solar generation	31,992	26,725
	$ 1,118,521	**$ 1,195,884**

Collection, late payment and other service charges are based on service charge rates and retailer rates as approved by the OEB. Pole attachment and other rentals consist primarily of pole attachment charges and charges for office and service centre space.

Miscellaneous includes revenues from City of Stratford and Town of St. Marys water and sewage billing services, street lighting services, management fees charged to Festival Hydro Services Inc. and other revenue sources.

18. Operating expenses:

	2022	2021
Salaries and benefits	$ 3,329,138	$ 3,003,417
External services	1,924,106	1,664,018
Materials and supplies	584,647	624,585
Other support costs	921,154	722,794
	$ 6,759,045	**$ 6,014,814**

19. Finance income and costs:

	2022	2021
Interest income on loan to corporation under common control	$ 10,862	$ 13,587
Interest on bank account	12,036	2,991
Interest on written off trade receivables	442	1,867
Unrealized gain on interest rate swap	1,723,834	646,085
Finance income	**$ 1,747,174**	**$ 664,530**
Interest expense on demand notes payable	$1,131,000	$1,131,000
Interest expense on long-term debt	338,185	378,136
Interest on revolving credit facility	84,552	24,449
Interest expense on deposits	21,041	6,207
Other interest expense	-	64,457
Finance costs	**$ 1,574,778**	**$ 1,604,249**
Net finance income (costs)	**$ 172,396**	**$ (939,719)**

Other interest expenses of $64,457 in 2021 are related to accrued interest and discharge fees for the early payment of the Infrastructure Ontario Projects Corporation (OIPC) loans with a combined principal payout of $842,668.

20. Related party transactions:

a) *Parent and ultimate controlling party*

The parent and sole shareholder of the Corporation is the Corporation of the City of Stratford (the “City”). The City of Stratford produces financial statements that are available for public use.

b) *Key management personnel*

The key management personnel of the Corporation has been defined as members of its Board of Directors and executive management team members. Total compensation of key management in 2022 was $833,946 (2021 - $662,748).

20. Related party transactions (continued):

(b) Transactions with the Corporation of the City of Stratford

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts, with the parent, the City of Stratford, for the years ended December 31:

	2022	2021
Revenues:		
Energy sales	$ 1,475,873	$ 1,612,278
Water and sewer administration fee	499,716	494,093
Street lighting services	18,760	34,878
Service centre space rental	33,477	27,638
Total revenues	$ 2,027,826	$ 2,168,887
Expenses:		
Interest on demand notes payable	$ 1,131,000	$ 1,131,000
Property taxes	121,157	118,062
Tree trimming	54,494	78,073
Total expenses	$ 1,306,651	$ 1,327,135

	December 31, 2022	December 31, 2021
Receivable balances:		
Accounts receivable	$ 371,073	$ 370,838
Payable balances:		
Accounts payable and accrued charges	$ 995,324	$ 996,298
Demand notes payable	15,600,000	15,600,000
Dividends payable	248,269	500,556
Total payables	$16,843,593	$17,096,854

The net amount owing to the Corporation of the City of Stratford for accounts receivable, accounts payable and accrued charges is $624,251 (2021 - $625,460).

Dividends paid or payable	$ 638,599	$ 890,886

20. Related party transactions (continued):

(c) Transactions with corporations under common control of the parent

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts, with Festival Hydro Services Inc., a wholly-owned subsidiary of the City of Stratford, for the years ended December 31:

	2022	2021
Revenues:		
Operational services	$ 33,397	$ 40,872
Management fee	64,851	57,518
Office and fibre room rentals	1,470	1,225
Joint pole rentals	55,308	71,311
Interest earned	10,862	13,712
Energy sales	28,689	25,687
Water billing and collection services	75,120	73,410
Total revenues	$269,697	$283,735
Expenses:		
Fiber and WIFI services	$154,148	$154,148
Information technology and management services	273,165	128,117
Total expenses	$427,313	$282,265

Receivable balance:		
	December 31, 2022	**December 31, 2021**
Due from corporations under common control	$122,147	$332,803

21. Capital management:

The Corporation's main objectives when managing capital is to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents or committed credit facilities) to meet the needs of the business;
- ensure compliance with covenants related to its credit facilities; and
- prudent management of its capital structure with regard to recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios. The Corporation manages capital by preparing short-term and long-term cash flow forecasts, statements of financial position and comprehensive statements of income. In addition, the Corporation accesses its revolving credit facility to fund net periodic net cash outflows and to maintain available liquidity.

There have been no changes in the Corporation's approach to capital management during the year. As at December 31, 2022, the Corporation's definition of capital included borrowings under its revolving credit facility, long-term debt and obligations including the current portion thereof, and equity, and had remained unchanged from the definition as at December 31, 2021. As at December 31, 2022, equity amounted to $34,039,035 (2021 - $30,296,146), borrowings in the form of demand notes payable and long-term debt, including the current portion thereof, amounted to $26,140,476 (2021 - $26,848,194) and the revolving credit facility amounted to $3,720,132 (2021 - $17,428).

21. Capital management (continued):

The OEB regulates the amount of deemed interest on debt and rate of return that may be recovered by the Corporation, through its electricity distribution rates, in respect of its regulated electricity distribution business. The OEB permits such recoveries on the basis of a deemed capital structure represented by 60% debt and 40% equity. The actual capital structure and finance costs for the Corporation may differ from the OEB deemed structure.

The Corporation is subject to debt agreements that contain various covenants. The Corporation's credit agreement with Royal Bank provides a revolving demand facility, letter of guarantee which is posted with the IESO as prudential support, and a long-term loan facility. These combined facilities are subject to a funded indebtedness debt to equity ratio of no more than 65%. Long-term lending arrangements with Infrastructure Ontario ("OICP") are subject to meeting a debt to equity test of no greater than 75:25 and debt servicing ratio of no less than 1.30 times.

The Corporation has customary covenants typically associated with long-term debt. As at December 31, 2022 and December 31, 2021, the Corporation was in compliance with all with all credit agreement covenants and limitations associated with its long-term debt.

22. Financial instruments and risk management:

Fair value disclosure

The carrying values of accounts receivable, unbilled revenue, and the revolving term facility, accounts payable and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair values of customer deposits approximate their carrying amounts taking into account interest accrued on the outstanding balance. Cash is measured at fair value.

The swap agreements are measured at fair value, which is provided by a third-party, banking institution and is based on market rates at the date of the valuation. The valuation of the interest rate swaps resulted in an unrealized gain recorded on the statement of financial position at December 31, 2022 of $784,886 (2021 - $938,948 unrealized loss).

The fair value of the long-term borrowings is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The carrying amounts and fair values of the Corporation's long-term loans consist of the following:

22. Financial instruments and risk management (continued):

	2022	2021
Carrying amounts:		
Demand notes payable, 7.25%	$15,600,000	$15,600,000
Term Loan 2.93% maturing May 1, 2038 plus stamping fee of 0.42% maturing May 1, 2023	9,875,000	10,366,000
Term Loan 2.62% maturing November 25, 2025	665,476	882,194
Total	**$26,140,476**	**$26,848,194**

	2022	2021
Fair values:		
Demand notes payable valued based on current revolving credit facility rate of 3.95%	$12,556,106	$16,422,603
Term Loan 2.93 % plus stamping fee of 0.42% maturing May 1, 2023, booked at market value	9,581,114	11,304,948
Term Loan 2.62% maturing November 25, 2025, booked at market interest rate of 2.95%	609,697	865,230
Total	**$22,746,917**	**$28,592,781**

Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed. The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

a) *Credit risk*

The Corporation is exposed to credit risk as a result of the risk of counterparties defaulting on their obligations. The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The Corporation's credit risk associated with accounts receivable and unbilled revenue is primarily related to electricity bill payments from electricity customers. The Corporation obtains security deposits from certain customers in accordance with direction provided by the OEB and as outlined in the Corporation's conditions of service. As of December 31, 2022, the Corporation held security deposits related to electricity receivables in the amount of $957,164 (2021 - $1,061,051).

22. Financial instruments and risk management (continued):

(a) *Credit risk (continued)*

As at December 31, 2022, there were no significant concentrations of credit risk with respect to any one customer. No single customer accounts for revenue in excess of 5% of total distribution revenue. The Corporation earns its revenue from a broad base of approximately 21,000 customers (2021 - 21,000 customers) located throughout its service territory.

The credit risk and mitigation strategies with respect to unbilled revenue are the same as for accounts receivable. The credit risk related to cash is mitigated by the Corporation's treasury policies on assessing and monitoring the credit exposures of counterparties.

Credit risk associated with electricity accounts receivable and unbilled revenue (electricity only) is as follows:

	2022	**2021**
Not more than 30 days	$ 6,448,968	$ 6,635,586
More than 30 but less than 90 days	405,840	295,071
More than 90 days	167,531	179,511
Less allowance for impairment	(173,017)	(178,684)
Unbilled revenue	4,783,498	5,230,771
	$ 11,632,820	**$12,162,255**

As at December 31, 2022, the Corporation's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk and no additional allowance for impairment was required for these balances.

Reconciliation between the opening and closing allowance for impairment is as follows:

	2022	**2021**
Balance, beginning of year	$ 178,684	$ 152,435
Provision for impairment	**53,870**	120,944
Write offs	(72,374)	(108,245)
Recoveries	12,837	13,550
Balance, end of year	**$ 173,017**	**$ 178,684**

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at year end. Unbilled revenue is considered current and no provision for impairment was established as at December 31, 2022 (2021 – nil).

(b) *Interest rate risk*

The Corporation is exposed to fluctuations in interest rates for the valuation of its employee future benefit obligations (note 12). The Corporation is also exposed to short-term interest rate risk on the net of cash position and short-term borrowings under its Revolving Credit Facility and customer deposits. The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments and taking action as necessary to maintain an appropriate balance.

22. Financial instruments and risk management (continued):

(b) Interest rate risk (continued)

As at December 31, 2022, aside from the valuation of its employee future benefit obligations, the Corporation was exposed to interest rate risk predominately from short-term borrowings under its revolving credit facility and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. The Corporation estimates that a 100 basis point increase in short-term interest rates, with all other variables held constant, would result in an increase of approximately $61,266 (2021 - $17,921) to annual finance costs. A decrease of 100 basis points would result in a reduction in financing costs of $61,266 (2021 – $17,921).

(c) Liquidity risk

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and monitors cash balances daily. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs.

The Corporation has a revolving credit facility available of $10,000,000 with a Canadian chartered bank. As at December 31, 2022, $3,720,132 (2021 - $17,428) was drawn on this facility.

As a purchaser of electricity through the Independent Electricity System Operator ("IESO"), the Corporation is required to provide security to minimize the risk of default based on its expected activity in the market. The IESO may draw on this security if the Corporation fails to make payment required by a default notice issue by the IESO. The Corporation has a $3.6 million revolving term facility by way of a letter of guarantee with Royal Bank, of which $3,095,139 (2021 - $3,095,139) has been assigned to secure the prudential support required by the IESO.

The majority of accounts payable, as reported on the statement of financial position, is due within 30 days.
Liquidity risks associated with financial commitments are as follows:

22. Financial instruments and risk management (continued):

Contractual cash flows, including interest, at year end are:

December 31, 2022

	Carrying Amounts	Total	Due within 1 year	Due within 1 to 5 years	Due> 5 years
Revolving credit facility	$ 3,741,355	$ 3,741,355	$ 3,741,355	$ -	$ -
Accounts payable and accrued liabilities	8,658,017	8,658,017	8,658,017	-	-
Due to City of Stratford	624,251	624,251	624,251	-	-
Demand notes payable	15,600,000	15,600,000	15,600,000	-	-
Term Loan 2.93 % plus stamping fee of 0.42% maturing May 1, 2038	9,875,000	12,645,318	828,224	3,308,138	8,508,956
Term Loan 2.62% maturing November 25, 2025	665,476	691,894	237,221	454,673	-
	$ 39,164,099	$ 41,960,835	$ 29,689,068	$ 3,762,811	$ 8,508,956

December 31, 2021

	Carrying Amounts	Total	Due within 1 year	Due within 1 to 5 years	Due> 5 years
Revolving credit facility	$ 17,428	$ 17,428	$ 17,428	$ -	$ -
Accounts payable and accrued liabilities	9,902,642	9,902,642	9,902,642	-	-
Due to City of Stratford	625,460	625,460	625,460	-	-
Demand notes payable	15,600,000	15,600,000	15,600,000	-	-
Term Loan 2.93 % plus stamping fee of 0.42% maturing May 1, 2038	10,366,000	13,475,135	829,817	3,311,494	9,333,824
Term Loan 2.62% maturing November 25, 2025	882,194	929,115	237,221	691,894	-
	$ 37,393,724	$ 40,549,780	$ 27,212,568	$ 4,003,388	$ 9,333,824

23. Commitments and contingencies:

Operating leases

The Corporation entered into a non-cancellable operating lease for service centre space for a period of five years dated November 15, 2015. The contract is subject to an annual increase based on the Ontario Consumer Price Index. Minimum lease payments required are $997 per month for 2022.

Connection and cost recovery agreement - St. Mary's transformer station

The Corporation and Hydro One Networks Inc. entered into a twenty-five-year capital cost recovery agreement ("CCRA") in September 2002 relating to Hydro One Networks Inc. building new feeder positions at the existing St. Mary's Transformer Station. Under the terms of the agreement, the Corporation has guaranteed new load growth which, if not met, would require the Corporation to provide a financial contribution toward the capital investment of the transformer station.

The CCRA has been trued-up effective July 5, 2013. Since load growth had fallen below a target amount, a cumulative contribution in the amount of $550,200 has been paid to Hydro One Networks. This amount has been recorded as an intangible asset subject to 15-year amortization over the remaining life of the agreement. The agreement was subject to true up effective on the fifteenth year of the agreement in July 2018 however, this has not been completed by Hydro One Inc. It is possible that the Corporation may owe a further payment as a result of the agreement but an estimate of any amount owing is not possible at December 31, 2022 given the nature of the variables included in the calculation. The need for a contribution will be determined by Hydro One Networks Inc. based on actual new load growth.

Connection and cost recovery agreement-Stratford transformer station ("Festival Hydro MTS1")

The Corporation and Hydro One Networks Inc. entered into a twenty-five-year CCRA in November, 2012, relating to Hydro One Networks Inc. building a new 230kV line to connect Festival Hydro`s MTS1 to Hydro One`s 230kV circuit. Under the terms of the agreement, the Corporation has guaranteed new load growth which, if not met, would require the Corporation to provide a financial contribution toward the capital investment. The CCRA is trued-up (a) following the fifth and tenth anniversaries of the in-service date; and (b) following the fifteenth anniversary of the in-service date if the actual load is 20% higher or lower than the load forecast at the end of the tenth anniversary of the in-service date. The fifth anniversary of the in-service date was in November 2017. The need for a contribution will be determined by Hydro One Networks Inc. based on actual new load growth.

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation’s financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (“MEARIE”). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2022, no assessments had been made.

24. Guarantee:

The Corporation has guaranteed the bank loan of QR Fibre, a company related through common ownership, to the extent of $4,500,000. In addition, the Corporation has entered into a Guarantee Indemnification Agreement to ensure compliance with the Affiliation Relationships code for Electricity Distributors and Transmitters and mitigate its risk exposure. No amount has been recorded in these financial statements as the Corporation does not expect to have to honour its guarantee.

25. Subsequent event:

The shares of QR Fibre Inc. held under common control were sold on January 31, 2023 for proceeds of $50,000. As of the date of sale, the Corporation is no longer obligated to honour the guarantee for the bank loan of QR Fibre.

26. Comparative figures:

Certain comparative figures have been restated to conform to the current year presentation.

Attachment 1 –19

FHI Amendments to Models

FHI Amendments to Models

Chapter 2 Appendices

- LDC info
  - F40 – Change dropdown to include 2013
- App.2-AA_Capital Projects
  - Added in “2015” column into “B”
  - Inserted 4 rows under system renewal
  - Inserted one row under general plant
- App.2-AB_Capital Expenditures
  - Inserted three columns (B-D) for 2015
  - U24 was blank – hardcoded number in
  - R24 was incorrect – hardcoded number in
  - C24 incorrect – hardcoded number in
- App.2-BA_Fixed Asset Cont
  - Fully Allocated Depreciation Calculation
    - Inserted two rows for Tools, Shop & Garage Equipment, and Communication Equipment for 205-2025
    - Changed Net depreciation calculation to include 2 new rows for 2015-2025
    - Inserted table for 2025
- Appendix 2-BB Service Life
  - Entered row 31 for “services”
  - Inserted row 36 for overall-TS
  - Inserted Rows 85-91
  - Inserted row 99
  - Inserted row 108 for primary energy meters
- App.2-AC_Customer Engagement
  - Inserted 2025
- App.2-G SQI
  - Value was missing from J31 – Hard coded it
- App.2-H_Other_Oper_Rev
  - Inserted 2015 column
  - Changed formula in row 65 to reference row25 instead of 15
  - Hardcoded F45, G45, and H45 for change to solar depreciation
  - VLOOKUPS in columns I and J not working, hardcoded the numbers
- App.2-IB_Load_Forecast_Analysis
  - Inserted columns for 2015-2018
  - Hardcoded data
    - RRR customer count based on year end – changed to average
    - Changes to greater than 50 2019-22

- App.2-IA_Load_Forecast_INSTRCT
  - Inserted 2015-22018
  - Hardcoded numbers in
- App.2-JA_OM&A_Summary_Analys
  - O&M not correct – hardcoded numbers
  - 2016 missing-inserted column
- App.2-JB_OM&A_Cost_Drivers
  - Inserted column for
  - 2016 Actual
- App.2-JC_OMA Programs
  - Added in column for 2016 actuals
- App.2-JD_OMA Programs
  - Inserted column for 2016 actuals
- App.2-K_Emploee Costs
  - Inserted column for 2016 actuals
- App.2-L_OM&A_per_Cust_FTE
  - Inserted column for 2016 Actuals
  - Updated cells F17:I17 to reference row 22 in tab App.2-JA and not row 21 in tab App.2-JA
- App.2N_Corp_Cost_Allocation
  - Inserted table for 2025
- App.2-OB_Debt Instruments
  - Inserted table for 2025
  - Changed formulas in J138 and J139 to account for loans that were paid off early and replaced

Cost Allocation Model

- I3 TB Data
  - Entered rows 133 and 134 for USoA accounts 1609 and 1611
- I6.1 Revenue
  - Formula in I39 was incorrect. Changed formula to add I25 instead of I26

Revenue Requirement Workform

- 8. Rev_Def_Suff
  - Changed formula in F34 to allow a negative value

Tariff Schedule and Bill Impact Model

- 6. Bill Impacts
  - OEB changed value in F266 to “0”

PILS model adjustments to formulas

- B1 Sch 1 Taxable Income Bridge
  - Cell F14 for Recapture is pulling from column S in tab “B8 Sch 8 CCA Bridge”, which is the recapture position in the 2024 model. In the 2025 model, recapture is listed under column Y. Modified formula of this cell in “B1 to pull from column Y in “B8 Sch 8 CCA Bridge”
  - Cell F71 for total CCA is pulling from column U in tab “B8 Sch 8 CCA Bridge”, which is the recapture position in the 2024 model. In the 2025 model, total CCA is listed under column AA. The formula of this cell in “B1 Sch 1 Taxable Income Bridge” to pull from column AA in “B8 Sch 8 CCA Bridge”
  - Cell F72 for Terminal Loss is pulling from column T in tab “B8 Sch 8 CCA Bridge”, which is the recapture position in the 2024 model. In the 2025 model, terminal loss is listed under column Z. The formula of this cell has been modified in “B1 Sch 1 Taxable Income Bridge” to pull from column Z in “B8 Sch 8 CCA Bridge”
- **T8 Sch 8 CCA Test**
  - The formula in column E for “UCC at beginning of test year is pulling from column W in “B8 Sch 8 CCA Bridge” tab. This was the old position of the ending UCC balance for the bridge year. That column has moved to column AB in the same tab. This formula has been updated to specifically connect with column AB in “B8 Sch 8 CCA Bridge” instead of W.
  - The CCA rate for these accounts is fixed each year. The amount claimed each year has been hardcoded.

Attachment 1 –20

CEO Certification of Evidence

Certification of Evidence

I, Jeff Graham, President, and CEO, hereby make the following Certifications regarding the information filed in the Festival Hydro Inc. 2025 Cost of Service Electricity Distribution Rate Application (EB-2024-0023) and any evidence filed in support of the Application:

1. I certify that the information filed does not include any personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act) unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable) in accordance with Chapter 1 of the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications, issued December 15, 2022.

2. I certify that the information filed in this Application is accurate, consistent, and complete to the best of my knowledge in accordance with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, issued December 15, 2022.

3. I certify that FHI has robust processes and internal controls in place for the preparation, review, verification and oversight of all deferral and variance account balances, regardless of whether the accounts are proposed for disposition, in accordance with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, issued December 15, 2022.

Jeff Graham

President and CEO

Festival Hydro Inc.

Attachment 1 –21

2025 Cost of Service Checklist

2025 Cost of Service Checklist

Festival Hydro Inc.

EB-2024-0023

Date: April 26, 2024

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	Practice direction followed
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 1 - Attachment 1-20
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 1 - Attachment 1-20
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 1 - Attachment 1-20
Ch2, p2	COS checklist filed and statement identifying all deviations from Filing Requirements	Exhibit 1 - Attachment 1-21, and live excel attached
2 & 3	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Each exhibit has related Appendices in PDF, live excel attached, Attachment 8-4 2024 Tariff Sheet pdf, live excel attached
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was amended	Exhibit 1 - Attachment 1-19
3	Regulated entity shown seperately from parent company or any other affiliates	FHI separate from affiliates and parent throughout Application
3 & 4	If applicable, if cost of service filed earlier than scheduled, justify why an early rebasing is required by demonstrating why and how distributor cannot adequately manage resources and financial needs during IRM period	N/A - last filing 2015
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	N/A - filed on time
4 & 5	All of the following exhibits filed: Application Overview and Administrative Documents, Rate Base and Capital (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	Completed and submitted
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	Completed
5	Documents must include page numbers and be provided in text searchable and bookmarked PDF format	Completed
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Completed and submitted
7	Materiality threshold: Explanation/justification and/or supporting evidence for material amounts pertaining to CAPEX, capital variances, rate base variances, OM&A, and DVAs; additional details below the threshold if necessary	Completed throughout, materiality calculated in 2.1.3.5
EXHIBIT 1 - APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	2.1.1 - Master Table of Contents included at beginning of Application. Each individual Exhibit has its own TOC which is appropriately bookmarked.
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. Also provide Strategic Plan, if available.	Attachment 1-11
8 & 9	Brief, plain language 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 and cost trends, 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 requested 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, new proposed charges, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans) -DVAs (total disposition ($) including split between customer classes and between RPP and non-RPP (if applicable), disposition period(s), new DVAs and requested discontinuation of DVAs) -Bill Impacts ($ 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 1 - 2.1.2.2
Administration		
9	Primary contact information (name, address, phone, email)	Exhibit 1 - 2.1.3.1
9	Identification of legal (or other) representation	Exhibit 1 - 2.1.3.2
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 1 - 2.1.3.3
9	Statement identifying where notice should be published and why	Exhibit 1 - 2.1.3.4
9	Form of hearing requested and why	Exhibit 1 - 2.1.3.6

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Festival Hydro Inc.

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Date: **April 26, 2024**

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
9	Requested effective date	Exhibit 1 - 2.1.3.7
10	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit 1 - 2.1.3.8
10	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 1 - 2.1.3.9
10	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 1 - 2.1.3.10
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 1 - 2.1.3.12

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
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 1 - 2.1.3.13
Distribution System Overview		
10	Description of Service Area - general description and map showing where distributor operates and communities served	Exhibit 1 - 2.1.4
Customer Engagement		
11	Provide information regarding its customer engagement activities, activities that occur on an on-going basis, and specific activities pertaining to application. **May** use Appendix 2-AC to assist in listing customer engagement activities	Exhibit 1 - 2.1.5, Appendix 2-AC not included
11	Ongoing Customer Engagement - Describe methods used to communicate and engage with each customer class regularly, summarize pertinent feedback received through regular customer communications, and explain how feedback informs operations and rate application, where applicable	Exhibit 1 - 2.1.5.1
11 & 12	Application-Specific Customer Engagement - Explain customer engagement process specific to application (tailor customer engagement activities to distributor's circumstances and the proposals in application). Demonstrate how customer needs and priorities were factored into the decision-making process	Exhibit 1 - 2.1.5.2
12	Customer engagement with customers who would be affected by proposals related to new rate classes, changes in to existing rate classes and change in charges such as RSCs, Specific Service Charges, standby rates, and unmetered-load customers	Exhibit 1 - 2.1.5
12	All responses to matters raised in letters of comment filed on public record	None at time of filing, will include as Letters of Comment Received
Performance Measurement		
12	Link to most recent scorecard	Attachment 1-16
12	Identification of performance improvement targets	Included in Business Plan - Attachment 1-11
12	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	Exhibit 1 - 2.1.6.2
12 & 13	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 1 - 2.1.6.2
13	Activity and Performance-based Benchmarking (APB) results - at least provide the following unit cost variance analysis: - Year-over-year Historical Actuals (for most recent APB results) - Forecast Bridge Year vs Historical Actuals, to extent possible - Test Year vs Historical Actuals, to extent possible	Exhibit 1 - 2.1.6.3
13	Explain variances in cost performance, whether changes in unit costs are within distributor's control, and discuss relevant actions planned or underway. Discuss econometric results to extent possible	Exhibit 1 - 2.1.6.3
Facilitating Innovation		
13 & 14	Distributors are encouraged to include a description of the ways their approach to innovation has shaped the application. Could include explanations of approach to innovation or keeping up with innovation in their business more generally; of specific projects or technologies for enhancing the provision of distribution services; and of enabling characteristics or constraints in their ability to undertake innovative solutions. Explain how innovative alternatives have been considered in place of traditional investments	Exhibit 1 - 2.1.7
14	Explain how innovative alternatives have been considered in place of traditional investments. Include information about the costs, expected benefits and associated risks of innovative alternatives	Exhibit 1 - 2.1.7
Financial Information		
14	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	Attachment 1-12 and 1-13
15	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable. If an Annual Information Form is filed publicly, a link should be provided	Attachment 1-16 and Attachment 1-18
15	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public debt and/or equity offerings	Exhibit 1 - 2.1.8.1
15	Any change in tax status	Exhibit 1 - 2.1.8.1
15	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit 1 - 2.1.8.2, 2.1.8.3
15	Accounting Standards used for financial statements and when adopted	Exhibit 1 - 2.1.8.1
15	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	Exhibit 1 - 2.1.8.4
Distributor Consolidation		
15	Information filed on the extent to which the distributor has investigated opportunities for consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	Exhibit 1 - 2.1.9
15	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	Not Applicable
A distributor filing an application to rebase following a consolidation must:		
15	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
16	Specify whether and which commitments made to shareholders are to be funded through rates	Not Applicable
16	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
16	Detail of efficacy of any rate plan confirmed as part of MAADs	Not Applicable
16	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	Not Applicable

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Impacts of COVID-19 Pandemic		
16	Distributors generally expected to reflect the impacts of the COVID-19 pandemic in their applications, including applicable forecast information. This includes, but is not limited to, the distributor's load forecast, capital forecast, and OM&A forecast in the applicable sections of the application	Exhibit 1 - 2.1.10
EXHIBIT 2 - RATE BASE AND CAPITAL		
Rate Base		
16	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. If not, specify whether variance explanations are on CAPEX or in-service additions basis	Exhibit 2 - 2.2.1.1
16	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 2 - 2.2.1.1
16	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Exhibit 2 - 2.2.1.1
Fixed Asset Continuity Schedule		
17	Completed Appendix 2-BA for each year - in Excel format	Exhibit 2 - Attachment 2-1
17	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 2 - 2.2.1.2 & 2.2.2
17	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	Exhibit 2 - 2.2.2.1
17 & 18	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 if 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	Not Applicable
18	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Not Applicable
18	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Exhibit 2 - 2.2.2.1, 2.2.4.3
18	All asset disposals clearly identified in Chapter 2 Appendices for all historical, bridge and test years	Exhibit 2 - Attachment 2-1, Exhibit 2.2.3.2
Depreciation, Amortization and Depletion		
18	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Exhibit 2 - 2.2.4.3
18	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	Exhibit 2 - 2.2.4.2 & Attachment 2-1
18	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	Exhibit 2 - 2.2.4.5
19	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit 2 - 2.2.4.6
19	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit 2 - 2.2.9.3
19	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Exhibit 2 - 2.2.9.2
19	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 2 - 2.2.4.4, Appendix 2-BB
Allowance for Working Capital		
19 & 20	Working Capital - 7.5% allowance or Lead/Lag Study. If previously ordered by OEB as part of last rate application to file Lead/Lag Study, must comply.	Exhibit 2 2.2.5
20	If Lead/Lag Study conducted - 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	NA - 7.5% used
20	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.	Exhibit 2 - 2.2.5, 2-ZA
20	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	Exhibit 2 - 2.2.5, 2-ZB
Distribution System Plan		
20	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Exhibit 2 - Attachment 2-2
Policy Options for the Funding of Capital		
21	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	Exhibit 2 - 2.2.7- No ACM proposed
21	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	Not applicable
21	Complete Capital Module Applicable to ACM and ICM	Not applicable
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
22	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	Exhibit 2 - 2.2.8- No previous ACM/ICM impacting Application
22	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
22	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
23	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
Capitalization		
24	Capitalization Policy: provide policy including changes since last rebasing application. Confirm if no changes made to capitalization policy since last rebasing application.	Exhibit 2 - 2.2.9
24	Overhead Costs: complete Appendix 2-D	Exhibit 2 - 2.2.10, 2-D
24	Burden Rates: identification of burden rates; if burden rates were changed since last rebasing, identification of the burden rates prior to the change	Exhibit 2 - 2.2.10
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
24	See Appendix A	Exhibit 2 2.2.11 - NA
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	Consistent with Chapter 5 sections
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)	DSP 5.2.1.2
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	N/A
Ch5, p5	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 of the current cost of service application..	DSP 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, which will be used as a baseline comparison in the performance measurement section below.	DSP 5.2.1.2-5.2.1.4
Coordinated Planning with Third Parties		
Ch5, p5	The distributor must demonstrate that it has 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 and relevant material supporting the effects the consultation had on the DSP.	DSP 5.2.2
Ch5, p5	Overview of consultation should include: purpose, outcome, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	DSP 5.2.2
Ch5, p5	A distributor should file the most recent regional plan. In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter.	DSP 5.2.2.6 and Appendix E-H
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	N/A
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 the following information in its capital plan: -number of consultations conducted and a summary of the manner in which the distributor determined with whom to consult; a summary of the results of the consultation; and a statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.	DSP 5.2.2.7
Ch5, p6	REG: -confirmation if there are 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	DSP 5.2.2.9
Performance Measurement for Continuous Improvement		
Ch5, p6 & 7	Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in Section 5.2.1.	DSP 5.2.3.1.1
Ch5, p7	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	DSP 5.2.3.1-5.2.3.2
Ch5, p7	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	DSP 5.2.3.2 (Table 5.25-Table 5.27)

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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	DSP 5.2.3.2 Table 5.26 and Table 5.27
Ch5, p7	Summary of major events that occurred since last cost of service	DSP 5.2.3.2.3 Table 5.28 and Table 5.29
Ch5, p7 & 8	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	DSP 5.2.3.2.3 Table 5.210-Table 5.213
Ch5, p8	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 distributors plan to deliver -summary of any feedback from customers regarding reliability on distributors' system -distributors that use SAIDI and SAIFI performance benchmarks that are different than the historical average - evidence provided to support reasonableness of benchmarks	DSP 5.2.3.3
Planning Process		
Ch5, p8	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text **may** be helpful	DSP 5.3.1.1
Ch5, p8	Summary of important changes in distributor's AM process since last DSP	DSP 5.3.1.2
Ch5, p9	Process: -provide processes used to identify, select, prioritize (including reprioritization over 5 year term), optimize, 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 -demonstrate how it does grid optimization using an approach that considers the distributor's whole system -consideration, where applicable, of assessing the use of non-wires alternatives, distributed energy resources, 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	DSP 5.3.1.3
Ch5, p9	Data -identification, description and summary of data used in processes above to identify, select, prioritize, optimize and pace investments over DSP	DSP 5.3.1.4
Overview of Assets Managed		
Ch5, p10	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, utilization, condition, failures/performance, asset risks, demographics) by major asset type that may help explain the specific need for the capital expenditure and demonstration of consideration of economic alternatives	DSP 5.3.2.1 & 5.3.2.2
Ch5, p10	Statement as to whether distributor has had any transmission or high voltage assets deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the current application	DSP 5.3.2.3
Ch5, p10	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	DSP 5.3.2.4
Asset Lifestyle Optimization Policies and Practices		
Ch5, p11	Demonstration that distributor has carried out cost-effective system O&M activities to sustain as asset to the end of its service life (and can include references to the Distribution System Code)	DSP 5.3.3.1 & 5.3.3.2
Ch5, p11	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	DSP 5.3.3.3.1 - DSP 5.3.3.3.3
Ch5, p11	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	DSP 5.3.3.3.4
Ch5, p11	Demonstration that the distributor has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints	DSP 5.3.3.1
Ch5, p11	Summary of important changes to the distributor's asset life optimization policies, processes, and tools since last DSP	DSP 5.3.3.4
System Capability Assessment for REG and DER		
Ch5, p11	Provide list of restricted feeders by name, the feeder designation, the reason for the restriction, number of connected customers, and explain if there are plans to improve the distribution system's ability to connect distributed energy resources	N/A
Ch5, p11	If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A	N/A
CDM Activities to Address System Needs		
Ch5, p12	Description of how distributor has taken CDM into consideration in its planning process	DSP 5.3.5
Ch5, p12	Any application for CDM funding to address system needs must include a consideration of the projected effects on the distribution system on a long-term basis and the forecast expenditures.	N/A
Ch5, p12	Explanation of proposed activity in the context of the DSP, including providing details on the system need that is being addressed, infrastructure investments that are being avoided or deferred as a result of CDM activity, and the prioritization of proposed CDM activity relative to other system investments in the DSP	N/A
Ch5, p12	Description of the approach to assessing the benefits and costs of CDM activity	N/A
Capital Expenditure Summary		
Ch5, p13	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	DSP 5.4
Ch5, p13	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	DSP 5.4 - Table 5.41 and Table 5.42

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Ch5, p13	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	DSP 5.4.1.2 - Table 5.412 - Table 5.416
Ch5, p13	Completed Appendices 2-AA and 2-AB	PDF in Exhibit 2 Attachment 2-1 and live models attached
Ch5, p13	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment or category, including actuals v. OEB-approved/planned amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances between planned and actual volume of work completed and explanation of variances in a given year that are much higher or lower than the historical trend	DSP 5.4.1.1 - Table 5.43-Table 5.411
Ch5, p13	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	DSP 5.4.1.2.5
Ch5, p14	Analysis of capital expenditures in DSP forecast period v. historical	DSP 5.4.1.3
Ch5, p14	Summary of any important modifications to typical capital programs since the last DSP	DSP 5.4.1.4
Ch5, p14	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	DSP 5.4.1.5
Ch5, p14	Statement that there are no expenditures for non-distribution activities in the applicant's budget	DSP 5.4.1.6
Justifying Capital Expenditures		
Ch5, p14	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	DSP 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, p15	General information on the project/program - Need, scope, volume of work expected to be completed, 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	Appendix A (Materiality Narratives) - "General Information on the Program/Project"
Ch5, p15	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	Appendix A (Materiality Narratives) - "General Information on the Program/Project" & "Evaluation Criteria and Information Requirements"
Ch5, p16	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	Appendix A (Materiality Narratives) - "Evaluation Criteria and Information Requirements"
Appendix A (if applicable)		
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	N/A
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	N/A
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
24	Weather normal load forecast provided	Exhibit 3 - Attachment 3-2
24	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	Attachment 3-3
24	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 3 - 2.3.1.1
25	Explanation of weather normalization methodology	Exhibit 3 - 2.3.1.1
25	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Exhibit 3 - Attachment 3-1

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25 & 26	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 should include, but not limited to, the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error and Durbin-Watson statistic), including explanation for any resulting non-intuitive relationships -explanation of weather normalization methodology (including if monthly HDD and/or CDD are 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 for purchased power -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	Exhibit 3 - 2.3.1.1 Exhibit 3 - Attachment 3-2
26	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 assumptions used	Exhibit 3 - 2.3.1.2
Incorporating CDM Impacts in the Load Forecast for Distributors		
27	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	2.3.1.3
28	If a distributor proposes a 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
Accuracy of Load Forecast and Variance Analyses		
28	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Exhibit 3 - Attachment 3-1
28	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 3 - 2.3.2
28	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 3 -2.3.2 & 2.3.1.1
29	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Exhibit 3 - Attachment 3-2
EXHIBIT 4 - OPERATING EXPENSES		
Overview		
29	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 4 - 2.4.1
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		
29	Summary of recoverable OM&A expenses; Appendix 2-JA	Exhibit 4 - 2.4.2
29	Recoverable OM&A cost drivers; Appendix 2-JB	Exhibit 4 - 2.4.2
29	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Exhibit 4 - 2.4.2
29	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Exhibit 4 - 2.4.2

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29 & 30	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	NA
30	Only distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed instead of 2-JC	Exhibit 4 - 2.4.2 - 2-JC selected
30	For all distributors, 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.	Exhibit 4 - 2.4.2
30	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories	Exhibit 4 - 2.4.2
30	Identification of change in OM&A in test year in relation to change in capitalized overhead	Exhibit 4 - 2.4.2
OM&A Variance Analysis		
30	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	Exhibit 4 - 2.4.3
30	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
30	For all distributors, the 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 4 - 2.4.3
Workforce Planning and Employee Compensation		
31	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	Exhibit 4 - 2.4.3.1
31	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
31	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	Exhibit 4 - 2.4.3.1
31	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 4 - 2.4.3.1
31	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 4 - 2.4.3.1
31	Most recent actuarial report; tax section of evidence agrees with this analysis	Attachment 4-2
31	For virtual distributors - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated distributor. Provide the status of pension funding and all assumptions used in the analysis	Not applicable
32	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 4 - 2.4.3.1
Shared Services and Corporate Cost Allocation		
32	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	Exhibit 4 - 2.4.3.2
32	For shared services among affiliated entities: type of service provided or received, pricing methodology	Exhibit 4 - 2.4.3.2
32	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 4 - 2.4.3.2
32	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	Exhibit 4 - 2.4.3.2
32 & 33	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit 4 - 2.4.3.2
33	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit 4 - 2.4.3.2
Non-Affiliate Services, One-Time Costs, Regulatory Costs		
33	Purchases of Non-Affiliated Services - copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit 4 - 2.4.3.3, Attachment 4-4
33	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
33	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	Exhibit 4 - 2.4.3.4
33 & 34	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 4 - 2.4.3.5, Attachment 4-1

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LEAP, Charitable and Political Donations		
34	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 4 - 2.4.3.6
34	For any charitable contributions claimed for recovery, detailed information provided	Exhibit 4 - 2.4.3.7
34	Confirmation that no political contributions have been included for recovery	Exhibit 4 - 2.4.3.7
Conservation and Demand Management		
35	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	Exhibit 4 - 2.4.4.1
35	Distributor should generally not include any forecast costs associated with partnership in the IESO's LIP within its revenue requirement; distributor can seek to recover partnership costs at a future date through the LIP deferral account. 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	Not applicable
Funding Options for Future Conservation and Demand Management Activities		
35	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
35	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
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
36	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision. Alternatively - distributor specific cost of capital with supporting evidence and justification	Exhibit 5 - 2.5.1
36	Completed Appendix 2-OA for last OEB approved and test years	Attachment 5-1
36	Completed Appendix 2-OB for historical, bridge and test years with respect to long-term debt, short-term debt, preference shares, and common equity	Attachment 5-1
36	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 5 - 2.5.1
Cost of Capital (Return on Equity and Cost of Debt)		
The following provided for each year:		
37	Calculation of cost for each capital component	Exhibit 5 - 2.5.2
37	Profit or loss on redemption of debt, if applicable	Exhibit 5 - 2.5.2
37	Copies of current promissory notes or other debt arrangements with affiliates	Attachment 5-2, 5-3
37	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 5 - 2.5.2
37	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?)	Exhibit 5 - 2.5.2
37	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Exhibit 5 - 2.5.2
37	Historical return on equity achieved	Exhibit 5 - 2.5.2
Not-for-Profit Corporations		Exhibit 5 - 2.5.2
37	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	Exhibit 5 - 2.5.3, Not applicable
38	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
38	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
38	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
38	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
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
38	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each) excluding energy costs and revenues and unregulated costs and revenues: -determination of net 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 6 - 2.6
38 & 39	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) and for which disposition is not being sought in the application.	Exhibit 6 - 2.6
39	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit 6 - 2.6
39	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	Exhibit 6 - 2.6
Revenue Requirement Work Form		
39	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Attachment 6-2
39	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	Not applicable
40	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 6 - 2.6
Income Tax or PILs		

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40	Must provide detailed calculations of income tax or PILS. Must include a completed Excel version of the PILs model available on the OEB's website, including derivation of adjustments for historical, bridge and test years. Regulatory assets and liabilities must excluded from PILs calculations when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts.	Attachment 6-4 and live model attached
40	Supporting schedules and calculations identifying reconciling items	Exhibit 6 - 2.6.2.1
40	Most recent federal and provincial tax returns	Attachment 6-3
40	Financial Statements included with tax returns if different from those filed with application	Not applicable
40	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	Exhibit 6 - 2.6.2.1
41	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit 6 - 2.6.2.1
41	Completion of the integrity checks in the PILs Model	Exhibit 6 - 2.6.2.1
41	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 6 - 2.6.2.1
41 & 42	May propose a mechanism to smooth the tax impacts over the five-year IRM term.	Not applicable
Other Taxes		
42	Account 6105 is not an OM&A account and should be excluded from all OM&A totals. Applicant should provide an explanation of how these tax amounts are derived.	Exhibit 6 - 2.6.2.2

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Non-recoverable and Disallowed Expenses		
42	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Exhibit 6 - 2.6.2.3
Other Revenue		
42	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Exhibit 6 - 2.6.3
42 & 43	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 6 - 2.6.3
43	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 historical years, the bridge year and the test year. Any differences must be reconciled	Exhibit 6 - 2.6.3
43	Revenue related to microFIT recorded as revenue offset in Account 4235 and not included as part of base revenue requirement	Exhibit 6 - 2.6.3
43	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	Exhibit 6 - 2.6.3
43	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	Exhibit 6 - 2.6.3
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
44	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	Exhibit 7 - 2.7.1
44	Description of weighting factors, rationale for use of default values (if applicable)	Exhibit 7 - 2.7.1
44	If distributor is choosing to use the same weightings as its previous rebasing application, a reference to the previous application provided	Not applicable
45	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.	Attachment 7-1 and live model attached
Load Profiles and Demand Allocators		
45	Update all classes' load profiles and update demand allocators, if class load profiles are unavailable, provide an explanation and commit to putting plans in place to remedy this for next time a cost allocation model is filed	Exhibit 7 - 2.7.1
45	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	Exhibit 7 - 2.7.1
45	If multivariate regression used, the following provided: -statistics and statistical tests related to 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)	Exhibit 7 - 2.7.1
46	Data and regression model and statistics used in the weather normalization of load profiles provided in Excel format (includes showing the derivation of any constructed variables)	Exhibit 7 - 2.7.1
46	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	Exhibit 7 - 2.7.1
46	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	Exhibit 7 - 2.7.1
46 & 47	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 - Cost of Serving Embedded Distributors	Not applicable
47	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	Exhibit 7 - 2.7.1.1
48	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).	Exhibit 7 - 2.7.1.1
48	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	Exhibit 7 - 2.7.1.2
48	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service	Exhibit 7 - 2.7.1.3

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Class Revenue Requirements		

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49	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.	Exhibit 7 - 2.7.2
Revenue to Cost Ratios		
49 & 50	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.	Exhibit 7 - 2.7.3
50	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
50	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	Not applicable
EXHIBIT 8 - RATE DESIGN		
50	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 8 - 2.8.1
Fixed Variable Proportion		
50 & 51	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	Exhibit 8 - 2.8.1
RTSRs		
51	Completed RTSR Model in Excel	Attachment 8-2 and in excel
51	RTSR information consistent with working capital allowance calculation; explanation for any differences	Exhibit 8 - 2.8.2
Retail Service Charges		
51	Distributors should note that the current retail service rates and charges were established on a generic basis and should refer to the most recent rate order for the current approved rates.	Exhibit 8 - 2.8.3
Regulatory Charges		
52	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	Exhibit 8 - 2.8.4
Specific Service Charges		
52	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	Exhibit 8 - 2.8.5
52	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 8 - 2.8.5, Exhibit 1 - 2.1.3.13
52	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	Not applicable
53	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	Exhibit 8 - 2.8.5
53	Revenue from SSCs corresponds with Operating Revenue evidence	Exhibit 8 - 2.8.5
Wireline Pole Attachment Charge		
53	Under the new regulation (Part VI.1: O. Reg. 842/21, (Electricity Infrastructure (Part VI.1 of the Act)), OEB is to establish a generic, province-wide pole attachement charge for 2022. The Regulation further requires the OEB to set the charge for 2023 and subsequent years by adjusting the prior year's charge for inflation. The Regulation provides that the annual charge will be established by order without a hearing.	Exhibit 8 - 2.8.5
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
54	Forecast LV Cost	Exhibit 8 - 2.8.6

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54	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	Exhibit 8 - 2.8.6
54	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Exhibit 8 - 2.8.6
54	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	Exhibit 8 - 2.8.6
54	Proposed LV rates by customer class	Exhibit 8 - 2.8.6
Smart Meter Entity Charge		
55	Current OEB-approved SMC charged until the OEB approved any updated SMC	Exhibit 8 - 2.8.7
Loss Factors		
55	Proposed SFLF and Total Loss Factor for test year	Exhibit 8 - 2.8.8
55	Statement as to whether LDC is embedded including whether fully or partially	Exhibit 8 - 2.8.8
55	Study of losses if required by previous decision	Not applicable
55	3-5 years of historical loss factor data - Completed Appendix 2-R	Exhibit 8 - 2.8.8
55	If proposed distribution loss factor >5% or is showing an increasing trend, 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	Exhibit 8 - 2.8.8
55	Explanation of SFLF if not standard	Exhibit 8 - 2.8.8 - standard used
55	Reconciliation between the application and RRR filing	Exhibit 8 - 2.8.8
Tariff of Rates and Charges		
55	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	Attachment 8-4, 8-5 and live excel models
55	Completed Bill Impacts Model	Attachment 8-3 and live excel model
56	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	Exhibit 8 - 2.8.9
56	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Attachment 8-5 and live excel model
Revenue Reconciliation		
56	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 8 - 2.8.10
56	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	Attachment 6-2
Bill Impact Information		
56	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)	Attachment 8-3 and live excel model
56	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 8 - 2.8.11
57	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 8 - 2.8.11
57	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
Rate Mitigation		
57	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.	Exhibit 8 - 2.8.12
Rate Harmonization Mitigation Issues		
58	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
58	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	Not applicable
58	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussionion of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	Not applicable
58	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
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
58	Summary table showing all active DVAs not disposed of yet, showing principal and interest/carrying charges, total balance for each account, whether account being proposed for disposition and whether the account is proposed to be continued or discontinued	Exhibit 9 - 2.9
58	In a separate section under the summary table: - For any account identified, provide an explanation as to why it is not being proposed for disposition - For any Group 2 account identified, provide an explanation as to why it is being discontinued	Exhibit 9 - 2.9
58	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	Not applicable
58	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 active 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.	Attachment 9-1 and live excel

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59	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 DVA continuity schedule	Exhibit 9 - 2.9
59	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”	Exhibit 9 - 2.9
59	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	Exhibit 9 - 2.9
Disposition of Deferral and Variance Accounts		
59	Refer to DVA Continuity Schedule Instructions for instructions on completing the DVA Continuity Schedule, annual updates and discussions on default treatments and expectations for DVAs	Exhibit 9 - 2.9.1
59	Provide confirmation that a distributor is allocating DVAs using an approved allocator. 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	Exhibit 9 - 2.9.1
60	Propose rate riders that dispose of the balances. If the distributor is proposing an alternative recovery period other than one year, explanation provided	Exhibit 9 - 2.9.1
60	Provide support (e.g., explanations, calculations) on how each material Group 2 balance is determined. For utility-specific Group 2 accounts that are not material, provide a brief explanation of the account balance and the relevant accounting order	Exhibit 9 - 2.9.1
Disposition of Accounts 1588 and 1589		
60	If a distributor has not implemented OEB’s February 21, 2019 accounting guidance, indication that this is the case	Exhibit 9 - 2.9.1.2
60	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	Exhibit 9 - 2.9.1.2
60	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	Not applicable
60 & 61	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	Exhibit 9 - 2.9.1.2
61	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	Attachment 9-2 and in live format
61	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 between the actual and expected balance that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	Exhibit 9 - 2.9.1.1
61	Completed reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.	Exhibit 9 - 2.9.1.2
Disposition of Account 1580, Sub-account CBR Class B Variance		
61	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year. - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB’s accounting guidance - Refer to DVA Continuity Schedule Instructions for further details on the treatment of CBR related sub-accounts	Exhibit 9 - 2.9.1.3
Disposition of Account 1595		
62	Distributors are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	Exhibit 9 - 2.9.1.4
62	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	Exhibit 9 - 2.9.1.4
Disposition of Retail Service Charges Related Accounts		
62 & 63	If there is a balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services - state whether Article 490 of APH has been followed; explanation if not followed	Exhibit 9 - 2.9.1.5
63	If the balances in Account 1518, Account 1548, or Account 1508 Sub-account Retail Service Charges Incremental Revenue are material, the distributor must identify drivers for the balance(s) and provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances	Exhibit 9 - 2.9.1.5
63	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account, as well as in Accounts 1518 and 1548, would be disposed to ratepayers in a future rate application, and the account subsequently closed. Distributors that have not yet done so in a COS application may forecast balances up to the end of the incentive rate-setting period and the OEB may consider disposing of the forecast amounts	Exhibit 9 - 2.9.1.5
Disposition of Account 1592, Sub-account CCA Changes		
63 & 64	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	Exhibit 9 - 2.9.1
64	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	Exhibit 9 - 2.9.1
64	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	Exhibit 9 - 2.9.1
64	If a distributor does not have a balance in this sub-account, the distributor must explain why	Not applicable
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		

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64 & 65	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	Exhibit 9 - 2.9
Disposition of Account 1508, Sub-account Pole Attachment Revenue Variance		
65	A table showing the calculation of the account balance, the annual balance broken down customer type, if applicable and: -the number of poles used in the calculation -the pole attachment charge incorporated in rates -the updated charge May also foecast the balance to the effective date of its new rates	Exhibit 9 - 2.9.1
Disposition of Distributor-Specific Accounts		
66	For any material, distributor-specific accounts requested for disposition (e.g., Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived and relevant accounting order should be provided. For distributor-specific accounts requested for disposition that are not material, provide a brief explanation for the account balance and the relevant accounting order.	Exhibit 9 - 2.9.1
Establishment of New Deferral and Variance Accounts		
66 & 67	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order with description of the mechanics of the account, provide examples of general journal entries and the proposed account duration	Exhibit 9 - 2.9.2
Lost Revenue Adjustment Mechanism Variance Account		
67	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	Exhibit 9 - 2.9.3.1
Disposition of LRAMVA		
68	Disposition sought of all outstanding LRAMVA balances related to previously established LRAMVA thresholds	Not applicable
69	Current version of LRAMVA Work Form (Excel)	Not applicable
An application for lost revenues should include:		
69	Final Verified Annual Reports if claiming lost revenues from savings from CDM programs delivered in 2017 or earlier	Not applicable
69	Participation and Cost reports and detailed project level savings in Excel format made available by the IESO	Not applicable
69	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	Not applicable
69	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	Not applicable
An application for lost revenues should also provide:		
70	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	Not applicable
70	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)	Not applicable
70	Statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation	Not applicable
70	Summary table with principal and carrying charges by rate class and resulting rate riders	Not applicable
70	Statement confirming recovery period; rationale provided for disposing the balance in the LRAMVA if one or more classes does not generate significant rate riders	Not applicable
70	Details related to the approved CDM forecast savings from the last rebasing application	Not applicable
70	Statement explaining how rate class allocations for actual CDM savings were determined by class and program for each year	Not applicable
70	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)	Not applicable
70 & 71	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 Excel format	Not applicable
71	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	Not applicable
For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information:		
71	Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application	Not applicable
71	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	Not applicable

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71	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	Not applicable
71	Confirmation that the distributor has received reports from the participating municipality that validate the number and types of bulbs replaced or retrofitted through the IESO program	Not applicable
71	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, types of bulb replaced or retrofitted, average demand per bulb)	Not applicable
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:		
71	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	Not applicable
72	Rationale for net-to-gross assumptions used	Not applicable
72	Breakdown of billed demand and detailed level calculations in live Excel format	Not applicable
For program savings up to December 31, 2022 for projects completed after April 15, 2019, a distributor should provide the following:		
72	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	Not applicable
72	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	Not applicable
Continuing Use of the LRAMVA for New CDM Acitivities		
72	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	Exhibit 9 - 2.9.3.1
72	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	Not applicable
72	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	Not applicable
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	Not applicable
Appendix A	Appendices 2-FA through 2-FC identifying all eligible investments for recovery	Not applicable
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