INTERROGATORY RESPONSES

EB-2024-0023

JULY 25, 2024

Festival Hydro INC.

www.festivalhydro.com

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OEB STAFF (STAFF) INTERROGATORIES

EXHIBIT 1 – ADMINISTRATION

1-STAFF-1
Interrogatory:

Activity and Program-based Benchmarking – Lines O&M
Ref 1: Exhibit 1, p. 39

Preamble:
From Festival Hydro Inc.'s (Festival Hydro) Activity and Performance-based Benchmarking (APB), Festival Hydro's unit costs for its O&M Lines for the 2018-2022 is $4,796.47 which is 167% higher than the distributor average for the same period. Festival Hydro projects Lines O&M unit costs to increase in the 2024 Bridge Year to $5,287.46 and the 2025 Test Year to $5,512.25, representing year-over-year increases of 15% and 4%, respectively.

Festival Hydro states that Lines O&M unit cost includes vehicles, stores and additional linespersons labour costs, allocated depreciation, and service centre building costs. Festival Hydro states that it likely includes more costs in this category than other utilities causing the metric to appear higher than the industry average. Festival Hydro states that it plans to investigate why these costs are higher than its peers. Festival Hydro forecasts that on a forward basis, unit costs are expected to only increase at inflation as no new programs are planned for future years.

Table 1: APB Results for Years 2018-2022

Activity	Measure	Festival Hydro Average Unit Cost (2018-2022)	Distributor Average Unit Cost (2018-2022)	Above/Below Average	Difference (%)
Lines O&M	$/Primary Circuit km	4,796.47	1,796.81	Above	167%

Table 2: APB Projections for Years 2023-2025

Activity	Measure	2023	2024 Projection	2025 Projection	2023-2024 Year-Over-Year Change	2024-2025 Year-Over-Year Change
Lines O&M	$/Primary Circuit km	4,597.12	5,287.46	5,512.25	15%	4%

Question(s):

a) Please confirm if Festival Hydro has completed its investigation on why its Lines O&M unit costs are higher than the distributor average for the 2018-2022 period. If yes, please provide the results of the investigation. If not, please confirm when the investigation is to be completed.

Response:

a) *FHI has not yet completed its investigation on why its Lines O&M unit costs are higher than the distributor average for the 2018-2022 period. This investigation is planned to be completed in 2025.*

1-STAFF-2
Interrogatory:

Scorecard metrics
Ref 1: Exhibit 1, p. 177

The application shows that the performance for New Residential/Small Business Services Connected on Time has been trending downwards – the score decreased from 99.25% in 2018 to 95.92% in 2022. Festival Hydro states that these results are expected to continue with a potential dip in telephone calls answered on time during the transition to the new Customer Information System which was implemented in 2024.

The application shows that the performance for Customer Satisfaction Survey Results has been trending downwards – the score decreased from 97% in 2018 to 93% in 2022. Festival Hydro states that it uses feedback from the survey responses to drive decisions.

Question(s):

a) Please confirm if Festival Hydro anticipates the performance for this metric to return to 2018 levels once the Customer Information System is implemented in 2024.

b) Please explain the downward trend in the Customer Satisfaction Survey Results metric. Please explain how Festival Hydro has used the feedback from customer survey responses to ensure the Customer Satisfaction Survey Results metric does not continue on a downward trend.

Response:

a) *The New Residential / Small Business Services has been trending downwards due to the quantity of new service requests required. In 2018, there were 118 layouts requested, in 2021 this increased to approximately 200 and has remained around this level since then. FHI expects that the response time statistics should remain relatively flat going forward but will continue to monitor for further negative trends.*

   As noted, FHI expects that calls answered on time may dip in 2024 but once the new CIS is fully integrated and staff are comfortable with the new platform that calls answered on time will return to more typical levels.

b) *In 2018 the customer satisfaction survey was completed by a different public opinion polling firm, so their methodology and questions may have been slightly* *different. In 2020, FHI moved to Oraclepoll which resulted in a 91% satisfaction rate, and this increased to 93% satisfaction in 2022. FHI strives for, and expects to see similar results in future surveys, as FHI feels that all results over the past several years are very strong. FHI uses these surveys to assess if there are alternative ways customers want to be communicated with or services that they would like provided. For example, it was noted that customers would like a way to report an outage. In 2024, FHI will have its customer outage map in place for customers. In 2022, FHI also asked customers about their interest in electric vehicles to assist in understanding customers' short- and longer-term plans and the potential impact on the distribution system.*

EXHIBIT 2 – RATE BASE AND CAPITAL

2-STAFF-3
<u>Interrogatory:</u>

NWS/CDM in Distribution System Planning
Ref 1: Exhibit 2, Distribution System Plan, p.161, 175 and 218.
Ref 2: Exhibit 2, p.295-301 (Material Investment Narrative, Investment Category: System Renewal, Project: System Re-establishment)
Ref 3: Exhibit 2, p.320-328 (Material Investment Narrative, Investment Category: System Service, Project: Distribution Automation)
Ref 4: Exhibit 2, Greater Bruce/ Huron Region Scoping Assessment Report, p.687
Ref 5: Exhibit 2, Southern Huron-Perth Sub-Region Integrated Regional Resource Plan
Ref 6: Exhibit 2, Greater Bruce – Huron Regional Infrastructure Plan

Preamble:
Throughout Exhibit 2, Festival Hydro mentions consideration of non-wires alternatives (which the OEB refers to as non-wires solutions, or NWS) in its distribution system planning processes. For some material investments, Festival Hydro also provides a narrative that details Festival Hydro's consideration of the viability of NWS for the project.

Question(s):

a) Please clarify how and where in Festival Hydro's distribution system plan development process identifies whether distribution rate-funded CDM activities/ NWSs may be a preferred approach to meeting a system need to avoid or defer spending on traditional infrastructure.

b) Please describe specific changes (if any) Festival Hydro has made or plans to make to its distribution system planning process to address requirements in the OEB's NWS Guidelines for distributors. How would documentation of Festival Hydro's consideration of NWS change when making decisions on electricity system needs with an expected capital cost of $2M or more as part of its distribution system planning?

<u>Response:</u>

a) *Through its planning process, FHI identifies the needs of its system and therefore considers projects and programs that can help address these. For each major project, FHI performs an options analysis. The analysis helps FHI identify different options that could meet its needs. As part of this process, FHI does consider the viability of NWS to deliver on these needs, and whether it could be the preferred solution. FHI will continue with this approach for any future investments and incorporate the OEB's NWS Guidelines for any single project greater than $2M.*

b) *FHI is aware of the OEB's new methodology that electricity distributors are to employ when assessing the economic feasibility of using non-wires solutions (NWS) to address defined system needs that was issued on May 16th, 2024. Going forward, FHI will incorporate this methodology into its options assessment analysis for any single project that is greater than $2M. FHI will first look to conduct a pre-assessment to identify if an NWS is a potentially viable solution, and will then conduct a BCA as appropriate, where a practical NWS has been identified as an alternative to the proposed traditional investment.*

In terms of documentation, when FHI performs its options analysis and is considering an NWS, FHI would include the outputs of its analysis using the OEB's outlined methodology.

2-STAFF-4
<u>Interrogatory:</u>

Building renovations
Ref 1: Chapter 2 Appendices, Tab 2-AA
Ref 2: Exhibit 2, pp. 51-53
Ref 2: Exhibit 2, Appendix B, Third-Party Building Assessment Report

Preamble:
At reference 1, the application shows that Building and Equipment costs have increased by $695K in 2023 and is expected to increase by $1.1M in 2024, representing a 190% and 104% increase year-over-year, respectively.

Table 3: Building and Equipment Cost Year-Over-Year Increase

	2022	2023	2024 Bridge Year
Building & Equipment ($)	365,904	1,060,506	2,165,000
Year-Over-Year Increase ($)	-	694,602	1,104,494
Year-Over-Year Increase (%)	-	190%	104%

At reference 2, Festival Hydro states that the increases in building costs was a result of administrative building renovation to customer service and finance area in 2023 and finishing admin building renovation for IT, meeting rooms, engineering, and metering in 2024.

At reference 3, the application includes a building condition assessment condition survey dated in September 2020. The building condition survey states that there are significant changes that need to be made in order to bring this building up to today's standards based on Accessibility Code Standards. Further stating that it is not mandatory to make any changes, however today, accessibility is becoming more relevant and is now integrated into most new building designs.

The survey includes the following list of building elements:

Building Elements

C Interiors
- C1010 Partitions
- C1030 Interior Doors
- C2010 Wall Finishes
- C2020 Stair Finishes
- C2030 Floor Finishes
- C2050 Ceiling Finishes

D Services
- D1010 Elevators & Lifts
- D2010 Domestic Water Distribution
- D2020 Sanitary Waste
- D2040 Rainwater Drainage
- D2050 General Service Compressed Air
- D3020 Heat Generating Systems
- D3030 Cooling Generating Systems
- D3040 Distribution Systems
- D3060 Ventilation
- D4010 Fire Suppression
- D4020 Standpipes
- D5020 Electrical Service & Distribution
- D5040 Lighting & Branch Wiring
- D5080 Miscellaneous Electrical Systems
- D6010 Data Communications
- D6020 Voice Communications
- D6030 Audio-Video Communications
- D7050 Detection and Alarm

E – Equipment and Furnishing
- E2010 Fixed Millwork

G – Building Site
- G2030 Pedestrian Paving

Question(s):

a) Based on the building list included above, please confirm which building elements incurred Building and Equipment costs in 2023 and 2024. Please provide a breakdown of the building renovation costs in 2023 and 2024 based on these building elements.

b) Please confirm what component of the building renovation costs were a result of costs directly related to adhering to the Accessibility for Ontarians with Disabilities Act (AODA) and current Accessibility Code Standards.

c) Please confirm how Festival Hydro has paced any buildings renovations that are directly related to AODA compliance.

Response:

a) Please refer to the table below for the requested information.

Building Elements	2023 Building Costs	2024 Building Costs
	Incurred Costs	Incurred Costs
A-B Substructure & Shell	$ 16,175.08	$ 254,903.14
A 1010 Standard Foundations		
A 4010 Slab on Grade	x	x
B1010 Floor Construction		
B1020 Roof Construction		x
B1030 Structure Support		x
B1080 Stairs		x
B2010 Exterior Walls		
B2020 Exterior Windows		x
B2050 Exterior Doors		
B3010 Roof Coverings		x
B3010 Metal Roofing		
C Interiors	$ 361,744.88	$ 556,773.69
C1010 Partitions	x	x
C1030 Interior Doors	x	x
C2010 Wall Finishes	x	x
C2020 Stair Finishes		
C2030 Floor Finishes	x	x
C2050 Ceiling Finishes	x	x
D Services	$ 410,681.79	$ 983,935.01
D1010 Elevators & Lifts		
D2010 Domestic Water Distribution	x	x
D2020 Sanitary Waste	x	x
D2040 Rain Water Drainage	x	x
D2050 General Service Compressed Air		
D3020 Heat Generating Systems	x	x
D3030 Cooling Generating Systems	x	x
D3040 Distribution Systems	x	x
D3060 Ventilation	x	x
D4010 Fire Suppression		
D4020 Standpipes		
D5020 Electrical Service & Distribution	x	x
D5040 Lighting & Branch Wiring	x	x
D5080 Miscellaneous Electrical Systems		
D6010 Data Communications	x	x
D6020 Voice Communications		
D6030 Audio-Video Communications		x
D7050 Detection and Alarm	x	x
E – Equipment and Furnishing	$ 150,763.42	$ 280,618.18
E2010 Fixed Millwork	x	x
G – Building Site		
G2030 Pedestrian Paving		

b) *Based a pro-rated square foot approach, the AODA portion of the washroom renovations in 2021 would be estimated at 22% of overall contract amount. The AODA portion of the 2023 renovations were mainly partitions, interior doors, furnishings, accessible lunchrooms, entry doorways and an accessible customer entrance, and would be estimated at 23%. Using the same rationale, the AODA portion of the 2024 renovations would also be 23% of the overall budget.*

c) *FHI paced AODA upgrades by completing them as each area was renovated. This allowed for them to be brought into AODA compliance, while ensuring that their implementation and locations were suited for both current and future needs of the company and the public. Many of the AODA compliance measures would not have made sense to do piecemeal (e.g. larger doors, partitions and pathways) without ensuring that their construction was part of the long-term plan and was in the proper location for the foreseeable future.*

2-STAFF-5
<u>Interrogatory:</u>

Customer Surveys
Ref 1: Distribution System Plan, Page 13

Preamble:
At reference 1, Festival Hydro noted that the majority of their customers claimed the following items were important and were willing to pay more each month (less than one dollar for each item): power outages, smart grid, utility's assets, tree trimming, new technologies and communication.

Question(s):

d) In any follow-up surveys, will Festival Hydro target more specific questions on the same topics to yield more productive and actionable survey results?

<u>Response:</u>

d) *In the second component of customer engagement, FHI did ask questions which expanded from the first survey in order to find out more specific preferences that were explicitly customer facing such as:*

"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%*
Continued 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%*

And,

"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%*

Outside of some customer facing investment questions, it can be very difficult to explain the complexity of all of the investments required in the Distribution System and the ultimate impact on rates within a short survey. FHI wanted to focus on areas where customer feedback could be used in its decision-making process and ensure that the investment in the survey is value-added.

2-STAFF-6

Interrogatory:

Safety
Ref 1: Distribution System Plan, Page 24, Table 5.2-4
Ref 2: Appendix 2-JC OM&A Programs

Preamble:
At reference 1, the Distribution System Plan provides a summary of Performance Measures, from 2015 to 2023, identifying the associated targets for each. Some metrics do not have targets, such as the Level of Public Awareness regarding Safety, under Operational Effectiveness. This metric appears to be in a slight downtrend since 2019, from 81% to 77% in 2023.

At reference 2, OM&A spending for Community Relations and Safety increased by 71% and 59% in 2024 and 2025, respectively, on a year-over-year basis.

Question(s):

a) Is Festival Hydro concerned by the slight downward trend relating to the level of public awareness regarding safety? What measures are Festival Hydro taking to improve public awareness relating to safety?

b) Does Festival Hydro anticipate an improvement in the Level of Public Awareness regarding Safety metric based on the higher spend projected in Community Relations and Safety for 2024 and 2025?

Response:

a) FHI is not concerned by the slight downward trend. This survey was completed again in 2024 and the results improved back to 81%. The FHI 2024 Public Safety Survey results have been included in Attachment 1.

b) FHI would like to see the Level of Public Awareness increase. However, the main reason for the increasing customer relations and safety costs in 2024 and 2025 is the reintroduction of the school safety program that was paused during Covid. FHI believes that having school aged children aware of safety risks will decrease the risk of safety occurrences for families within its communities. This may not directly tie to improved survey results.

2-STAFF-7
Interrogatory:

Foreign Interference
Ref 1: Distribution System Plan, Page 31

Preamble:
In reference 1, Festival Hydro notes that Foreign Interference is the 3rd largest cause of outages, at 13%. Noting the types of foreign interference, such as animal interference,

dig-ins, vehicle collisions, vandalism, and/or foreign objects, Festival Hydro states that some preventative measures can be taken:

> "Some of these contributing factors can be minimized by installing wildlife guards, increasing clearances between conductors and poles, as well as educating the public about electrical overhead and underground electrical hazards, all of which FHI (Festival Hydro Incorporated) continues to do. However, there are also factors such as vehicle collisions which can happen at random and, depending on the extent and the location of the collision, may result in an increased duration and number of customers affected from the outage. These are typically outside FHI's control."

Question(s):

a) Regarding Foreign Interference, Festival Hydro notes the randomness of vehicle collisions, yet also notes that the extent and location of the collision could impact the duration and number of customers affected from the outage. Has Festival Hydro considered reinforcing key elements within its distribution system that could be susceptible to vehicle collisions that could prevent a vehicle collision from leading to a prolonged outage impacting their customer base? If so, would such investments be cost-effective, considering the potential impact on customers (i.e., by using a value of lost load)? What value of lost load would Festival Hydro reference in this case?

Response:

a) FHI has not considered reinforcing key elements within its distribution system in areas that vehicle collisions could occur. As indicated, the location of these has been random and in various areas throughout FHI's service territory, making it difficult to address, which also means we would be unable to reliably predict the value of lost load. When FHI replaces poles, the setbacks provided by the municipality are followed, however the locations are reviewed for a more favorable option where available.

2-STAFF-8
Interrogatory:

Net Capital Expenditures
Ref 1: Exhibit 2, Rate Base and Capital, Page 56
Ref 2: Distribution System Plan, Page 64

Preamble:
There are discrepancies in Net Capital Expenditures in 2023 and 2024 between reference 1 and reference 2.

Question(s):

a) Please confirm which values are correct.

b) Please confirm whether edits are required for the calculation of rate base in the Test Year based on the answer in a) above. If the rate base is calculated with incorrect values, please update the calculation of the revenue requirement.

Response:

a) The DSP has been updated and agrees to reference 1.

b) No edits are required for the calculation of rate base in the Test Year.

2-STAFF-9
Interrogatory:

Fleet
Ref 1: Distribution System Plan, Page 84
Ref 2: Distribution System Plan, Appendix A, Material Investment Narrative, General Plant, Fleet
Ref 3: Exhibit 2, p. 53

Preamble:
At reference 1, Festival Hydro plans to replace fleet vehicles, alternating between passenger vehicles and bucket trucks to smooth future spending, with Festival Hydro pointing to the results from the Asset Conditions Assessment as the reasoning behind the pace of investment.

At reference 2, Festival Hydro indicates that one of the pick-up trucks (Vehicle 14) to be replaced has been in service since 2013, noting the issues with the vehicles as follows: very high mileage, general rust and corrosion (mainly along doors and wheel wells), interior condition (seats and liners) and increasing maintenance costs. The table showing the maintenance costs of Vehicle 14 is referenced below. OEB staff calculates that maintenance costs on a per km basis have ranged between $0.07/km to $0.20/km during the 2018-2023 period. The application states that the health index for fleet vehicle condition is a function of mileage and age.

Table 4: Maintenance Costs for Vehicle 14 (Pick Up Truck)

	2018	2019	2020	2021	2022	2023
Maintenance Costs ($)	2,257	2,748	1,138	798	3,974	3,655
Mileage (kms)	12,058	13,476	13,995	11,884	23,653	19,186
Maintenance Cost / Mileage ($/km)	0.19	0.20	0.08	0.07	0.17	0.19

At reference 3, the application states that fleet capital costs are expected to increase from $92.9K in 2023 to $450K in 2024, representing a 384% increase. At reference 3, Festival Hydro states that a new 42' single bucket truck is budgeted for 2024.

Question(s):

a) Provide additional detail regarding the type of vehicles selected to replace the existing fleet (ICE or EV) and the business case or analysis used to determine the lowest cost options for Festival Hydro.

b) What is the strategy for vehicle utilization regarding the current state of the fleet?

c) The maintenance cost on a per km basis does not materially change during the 2018-2023 period for Vehicle 14 (Pick Up Truck) and appears to only increase based on the usage of the vehicle. Can Festival Hydro further explain the need to urgently replace Vehicle 14?

d) Please confirm if the driver for the $450K fleet costs projected for 2024 is due to the new bucket truck alone. If not, please explain the driver for the increased fleet cost in 2024.

e) Please confirm if the new bucket truck is anticipated to be delivered in 2024. If not, please confirm when the delivery for the bucket truck is anticipated.

f) Please confirm if the new bucket truck is replacing an old bucket truck. If yes, please confirm which bucket truck it is replacing.

Response:

a) FHI has historically only purchased ICE to replace existing fleet vehicles. FHI completes a competitive tender process for all fleet vehicles purchased and evaluates each submission to ensure that the needs of the company are met at the most competitive price. Electric options are beginning to be considered, where prudent.

b) FHI has no set threshold for vehicle utilization for its fleet. However, the goal is to optimize the size and type of vehicles in their fleet. Since 2015, FHI has lowered its fleet from 25 to 22 vehicles. The aim with small fleet vehicles is to have one for each Operations staff (e.g. line supervisor and utility serviceperson) that are *used daily and have one floating vehicle for each department (Engineering and Metering). Meaning that in general 82% of these vehicles are used continuously, while the two remaining vehicles are used regularly by office staff for site and customer visits.*

The strategy with large vehicles is that each vehicle has specific functions or limitations, and all are needed to ensure crews have the resources available to effectively complete their work. For example, single bucket trucks and RBDs, which are the most commonly used large vehicles, are purchased in a quantity to ensure that each crew has one available to them when needed and are typically used on a daily basis. The utilization of any of the specialty vehicles (such as knuckle boom crane or U/G service truck) in FHI's fleet depends on the type and quantity of work each day.

c) *FHI also looks at other factors such as total maintenance costs, frequency of maintenance and overall mileage. Vehicle 14's overall maintenance costs have increased, and while from a cost/km the rate may seem level, the maintenance costs compared to newer vehicles is significantly higher. For example, vehicle 17, which was purchased in 2022 and had a comparable amount of mileage in 2023, only had $515 in maintenance costs, or 14% of vehicle 14's.*

   Vehicle 14, which is used daily by operations staff, has also seen increasing maintenance intervals over the historical years. In 2023 it required 5 separate mechanic visits, when over previous years this number averaged 2 or 3, and given FHI's goal of optimizing fleet size, having vehicles unexpectedly unavailable decreases availability of other vehicles for staff. In order to maintain FHI's current complement of vehicles, vehicles in poor condition and that are becoming increasingly unreliable are replaced.

d) *FHI confirms that the new bucket truck is the driver for the $450k fleet costs in 2024.*

e) *FHI has received an update from the manufacturer that due to a chassis delay, delivery of the bucket truck will now take place in 2025.*

f) *FHI confirms that the new bucket truck is replacing an old bucket truck. It is replacing Vehicle number 6 as shown in Table 1 of FHI's "Fleet" Materiality Narrative.*

2-STAFF-10
<u>Interrogatory:</u>

Grid Modernization and Resiliency
Ref 1: Distribution System Plan, Page 90
Ref 2: Distribution System Plan, Page 89

Ref 3: Distribution System Plan, Appendix A, Material Investment Narrative, System Service, Distribution Automation

Preamble:
At reference 1, the Distribution System Plan describes a position at Festival Hydro created in 2022 with a portion of the job responsibilities being “grid modernization and resiliency”.

At reference 2, Festival Hydro proposes continued addition of distribution automation to its distribution system each year for the forecast period. Specifically, the proposed investment will add one recloser and one set of remote fault indicators to the distribution system each year to enhance the grid modernization of its system.

At reference 3, as part of the Investment Justification for Distribution Automation, Festival Hydro notes that they are at “the beginning of its grid modernization investments, and therefore has not seen the outputs of its investments yet.”

Question(s):
a) Please provide quantitative data on the cost-effectiveness of the distribution automation investments mentioned at reference 2.

b) Were any other grid modernization investments considered but not added to the plan, as they were not considered cost-effective? If so, which investments?

c) How do the planned grid modernization investments align with current OEB initiatives, such as the Benefit-Cost Analysis Framework?

Response:
a) *As mentioned in Reference 3, FHI is still at the beginning of its grid modernization investments, and therefore has not seen the output of these investments yet. However, as discussed in Reference 3, based on the previous 5 years, in theory the installation of remote fault indicators could have resulted in 40 outages that would no longer require truck rolls and resources to drive to these communities as the devices would have indicated the cause of the outage was in Hydro One territory.*

   In 2024, FHI has had one instance where a truck did not need to be sent to the community where fault indicators were installed in 2023 based on the information received from these devices. Each truck roll saved is estimated at approximately $1,000, but depends on circumstances such as time of day, size of community, and location of crews.

   At this time, as FHI has not installed any reclosers; it is unable to quantify the cost effectiveness of the investment. However, based on the targeted locations that FHI intends to install these devices, it is expected to have benefits to customers by minimizing the number of customers impacted under outage *events, and assist FHI staff in pinpointing fault locations quicker, based on information on the status of the reclosers, and by being able to remotely switch certain points in FHI's system rather than have to send a crew to manually operate the switch (which is estimated at $500-$1,000 depending on circumstances such as time of day and location of crews).*

b) *FHI did not consider other grid modernization investments for the test and forecast years. FHI sees the planned investments as being foundational for FHI to make the transition to a modern grid, and as this transition matures and these devices are installed in the distribution system, FHI will then look at more options to further leverage the capabilities and functionalities of these investments.*

c) *As outlined in the answer in part b) of this question, FHI is focusing its grid modernization investments on having the foundational elements in place during this forecast period. These foundational elements will then allow FHI to investigate more advanced grid modernization technologies. These foundational elements also allow FHI to potentially look at other NWS that it might be able to enable instead of traditional investments, which would then allow FHI to use the OEB's BCA framework to analyse the prudency of these NWS investments.*

2-STAFF-11
<u>Interrogatory:</u>

Pole Replacement Program
Ref 1: Material Investment Narrative, System Renewal, Overhead Pole-Line Replacement
Ref 2: Material Investment Narrative, System Renewal, Unplanned Small Replacements

Preamble:
At reference 1, Festival Hydro describes the conditions of its existing poles and describes at a high-level the process for planning pole replacements:

> "As part of the ACA, Kinectrics identified that 890 wood poles and 129 concrete poles (17% of all poles) were in poor or very poor condition. Identification of poles as part of this program is a multi-step process beginning with the field inspection and testing data collected as part of the asset management process. The data collected as part of this effort informs the ACA, and this data is then imported into GIS to be viewed spatially. Poles in close vicinity to each other with similarly poor health indices are then grouped together to create a capital pole line rebuild project where feasible. Each project scope includes the design, construction and installation of new poles framed to conform to O. Reg. 22/04 compliant standards. Through this project, FHI plans to improve the level of safety and reliability associated with newer standards and materials. As part of this program FHI plans to replace on average 60-75 poles per year."

Festival Hydro also states that "by identifying and proactively replacing poles nearing their end of life and in deteriorated condition, FHI mitigates the risk of outages and provides a safer electrical distribution system". Additionally, Festival Hydro states that "the planned, proactive replacements that are enabled as a result of this project is less costly than reactive replacements".

At reference 2, Festival Hydro notes the historical investments of Unplanned Small Replacements, which includes the replacement of 12-18 poles and 10-12 padmount transformers per year.

Question(s):

a) Please explain the approach and the analysis that selects pole groupings that include different conditions (e.g., both fair, poor and very poor) and comment on how such an approach most effectively replaces the most urgent of the 170 poles deemed to be in very poor condition.

b) What metric or threshold is used to qualify a pole grouping for replacement, as it relates to asset condition?

c) When replacing assets prior to the end of life such as poles, does any of the associated equipment get reused (e.g., overhead transformers)?

d) How many transformers and switches are also being replaced as a result of pole replacement?

e) Please confirm if there are poles being replaced under the subdivision, voltage conversion, and distribution automation programs that would be included in the yearly 60-75 pole replacement count.

Response:

a) *FHI takes ACA condition results and imports them into their GIS system to spatially view the location of the assets and understand where there are groupings of assets in different conditions.*

   In areas where a majority of poles are in poor or very poor condition, a more thorough analysis is taken to identify a constructable project in this area, and what assets need replaced (e.g. just poles, or replacement of associated hardware as well). In 2025, under the overhead pole line replacement program, 19 of the poles being removed have been deemed in very poor condition, with a further 26 of the poles being deemed in poor condition. By combining these into constructable projects, FHI gains efficiencies by having the crews set up in the same location for work, meaning that more poles can be replaced at a more efficient cost.

   In locations where poles have been identified as being in very poor condition, but others in a close geographic area are not grouped into similar health indices, *they are replaced on a like for like basis under the Unplanned Small Replacements program. These replacements almost exclusively replace very poor condition assets.*

By combining these two programs, FHI balances the efficiencies of replacing entire pole lines where conditions indicate, while still leaving flexibility to address very poor condition poles that do not merit full rebuilds to effectively replace urgent poles.

b) *FHI's threshold is to have over half the poles being replaced in any project be deemed in poor or worse condition. Once that occurs, these projects are compared against each other to identify any other benefits this project may bring.*

c) *Yes, FHI examines on a project-by-project basis what associated equipment is suitable for re-use (e.g. transformers, insulators, conductor), and does so where appropriate.*

d) *In 2025, there are ten transformers being replaced as part of the pole replacement project. Each transformer replaced, has the associated switch replaced as well. There is one additional switch that will be replaced as well.*

e) *There are no poles replaced under any of the above-mentioned programs that are included in this yearly pole count.*

2-STAFF-12
Interrogatory:

Switchgear Replacement
Ref 1: Material Investment Narrative, System Renewal, Switchgear Replacement

Preamble:
At reference 1, Festival Hydro describes the replacement program for air-insulated switchgear to be replaced with solid di-electric switchgear, noting the very poor condition of the existing equipment, with 10 of 12 of the existing switchgear equipment in poor or very poor condition. There have been multiple equipment failures from the existing air-insulated switchgear, with 27 outages from switchgear failures. Festival Hydro plans to replace two switchgear per year, until 2026.

Regarding Alternative Analysis, Festival Hydro considered: Do Nothing, Replace like for like, replace with solid di-electric switchgear (preferred option), decrease pace, and removal of the asset (done where appropriate).

Festival Hydro also notes that "the proactive replacement strategy of the project as planned is less costly than reactive replacements", while also reducing outage length.

Question(s):

a) Considering that Festival Hydro states that the proactive replacement is less costly than reactive replacements, can Festival Hydro comment on why increasing the pace of air-insulated switchgear replacements would not also be less costly than reactive replacement? Please estimate the cost savings from proactively replacing the switchgear opposed to reactive replacement.

b) Considering the state of the air-insulated switchgear and the importance of functional switchgear to the integrity of the system, should Festival Hydro consider increasing the pace of its replacements from two per year and complete the program sooner than 2026? In other words, looking at the Alternative Analysis, “decrease pace” was considered, however, “increase pace” was not. Why not?

    i. If Festival Hydro was to consider an increased pace, what would the investment be over the forecast period?

c) Regarding the Alternative Analysis, no thorough operational solution was considered, for example, to repair only the impacted elements instead of replacement. Why not?

Response:

a) *Based on recent historical costs of reactive replacement vs. proactive replacement, there is a savings of approximately $10,000.*

   Making the assumption that these switchgear will fail prior to replacement, the cost savings from replacing the switchgear proactively vs. reactively would be expected to be similar.

   However, FHI has not budgeted any reactive replacement of switchgear in their test or forecast years, pacing the investments to proactively replace the remaining switchgear in what it believes is a responsible manner, and allows for a balanced and paced overall capital investment approach.

b) *Increased pace was not included in the narrative because of the number of remaining switchgears that will be in service over the forecast period. FHI will be down to their final four air insulated switchgear and feel that the pacing proposed is sufficient to eliminate the final four switchgears prior to sustaining an unexpected failure as 2025 will see two switchgear replaced that are in very poor condition, and 2026 sees two switchgear replaced that are in poor condition. If all four remaining switchgear had the same very poor condition rating, FHI would have considered increasing the pace, but due to the high cost of a single switchgear (over $100,000) FHI feels that allocating these costs to other investment categories such as pole and underground cable replacement, given the higher number of assets in very poor condition and trying to stay within the current budget envelope, is the best allocation of funds.*

i. *If FHI increased its pace, the investment over the forecast period would be the same, it would just shift the 2026 cost of $244,000 into 2025.*

c) *FHI did not consider the replacement of only impacted elements for multiple reasons.*

The first is that many of the switchgear have multiple issues that would require repairs, and not just the replacement of a single piece of equipment. FHI has also experienced multiple failures of different varieties from these assets, so there is no single piece of equipment within the switchgear responsible for these outages that could be targeted to replace, and replacing one element does not necessarily mitigate the risk of failure at that unit.

Also, as these switchgear are all air insulated, there are inherent safety risks to both the public and employees that are eliminated with the replacement solid dielectric units that are deadfront.

2-STAFF-13
Interrogatory:

AMI 2.0
Ref 1: Material Investment Narrative, System Access, AMI 2.0

Preamble:
Festival Hydro presents its need to replace its AMI 1.0 infrastructure with AMI 2.0 including smart meters, repeaters, collectors, Head End System (HES), and related software and firmware. Festival Hydro states that the AMI 1.0 system comprises approximately 23,000 smart meters interconnected through a mesh network. Furthermore, it also states that it plans mass replacement of 4500 meters in 2025, 5600 meters per year for 2026 to 2028, and 1100 meters in 2029, totalling to 22,400 meters.

Under section 2 - Timing, Festival Hydro states that one of the key factors that could impact the project schedule could be “potential resource constraints and this risk will be mitigated by completing labour forecasting early to identify staffing requirements for the project well in advance”.

Under section 2 – Timing, Festival Hydro states that “There is a residual risk of premature meter component failures as is the case with any electronic equipment. This risk is mitigated by negotiating a warranty period with the new vendor for all hardware and equipment.”

Festival Hydro states that one of the outcomes of the AMI 2.0 investment will be “Improve operational effectiveness and efficiency (e.g., reduction in field visits for manual meter reading and disconnection/reconnection requests, reduction in network management and data backhaul costs, reduction in IT HES costs, provision of new data sets for operational decision-making, etc.)”.

Question(s):

a) Does the scope for meter replacement include all the residential meters and smart meters used for commercial services? Does this include the ones that would have been replaced in most recent years? If not, how many meters from AMI 1.0 will be reused in AMI 2.0?
   i. What is the forecast value of meters disposed of prior to being fully depreciated? Where will this be recorded?

b) Will Festival Hydro use internal or external contracted resources to execute this program? If Festival Hydro is using internal labour resources, has it forecasted the need and what are the plans to hire those resources?

c) Given the challenges Festival Hydro went through with respect to the quality of meters used in its AMI 1.0 system, what precautions is it taking to mitigate such risks for its AMI 2.0 system? Please provide any specific information on expectations such as warranty or support periods that Festival Hydro would have included in its AMI 2.0 RFP.

d) Is Festival Hydro able to quantify the total OM&A savings related to activities such as manual meter reads and disconnection service resulting from this AMI 2.0 investments?
   i. Has Festival Hydro considered these savings while developing OM&A budgets for the test and forecast years?

<u>Response:</u>

a) *The scope includes the replacement of all residential meters, and all commercial meters that use the AMI 1.0 network infrastructure. This would include meters that have been purchased in more recent years. There will still be large commercial meters that use FHI's MV90 network that will not be replaced under this program.*

   i. *The forecast value of meters being disposed of prior to being fully depreciated is approximately $84,000 that will need to be written off. In the interim period, FHI will look to re-use working AMI 1.0 meters as existing ones fail, rather than purchase new.*

b) *FHI will use a mixture of internal and external labour resources to complete this work. Because the meters will all be replaced in close geographic location to one another, increasing the efficiency of how many meters can be replaced by an individual on a daily basis, FHI does not forecast the need to hire any additional internal resources to complete this project.*

c) *In order to mitigate risks for the AMI 2.0 deployment, FHI put the following warranty expectations in their AMI 2.0 RFP.*

Meter Equipment Warranty that will ensure the hardware will conform to the design functionality and be free from defects and deficiencies.
Network Equipment Warranty that will ensure the hardware will conform to the design functionality and be free from defects and deficiencies.

Meter Safety Failure Warranty that will ensure that if there is a safety incident with the meter that safety rectification plan will be created and paid for by the vendor

Major Failure Meter Warranty that will ensure that if a certain percentage of the meter population that fails for the same cause, there will be a failure resolution plan to rectify the issue created and paid for by the vendor

FHI also required information from vendors on their response and resolution timeframes, levels of support, support tools, hours of support and support severity level definitions. Furthermore, these meters have been successfully installed by other electric utilities already.

d) Based on historical amounts, FHI estimates that remote disconnect and reconnect capabilities could save up to $6,000-$7,000 each year, and approximately $35,000 yearly in manual meter reads. These estimated savings would not be seen until the entire AMI 2.0 program has been deployed as these costs and tasks are spread across FHI's entire service territory.

   i. *FHI has considered these savings, however OM&A savings will likely not be seen until 2027. In the interim periods, 'good' meters that are removed from converted areas will be relocated to replace failing meters in areas that have not yet been converted.*

2-STAFF-14
Interrogatory:

Underground Renewal
Ref 1: Material Investment Narrative, System Renewal, Underground Renewal
Ref 2: Distribution System Plan, Page 30
Ref 3: Distribution System Plan, Appendix J - Kinectrics 2023 Asset Condition Assessment, Page 60

Preamble:
At reference 1, Festival Hydro states that the underground renewal program targets investments to address underground assets within its system that are in poor or very poor condition.

Table 5.2-11 on page 30 of distribution system plan shows that the defective equipment contributes to 14% of the outages.

The asset condition assessment formula for underground cables at reference 3 states that due to unavailability of condition data health index is solely based on the age of the cables.

Question(s):

a) What other criteria does Festival Hydro use besides the health index or age to determine whether the underground cable needs to be replaced?

b) Is Festival Hydro able to provide the breakdown of defective equipment related outages by asset type? How many defective equipment outages are due to underground cable failure?

Response:

a) Historically FHI has mainly relied on health index and age to assist in prioritizing underground cable replacement.

However, FHI has also started to consider other factors such as:

- *Cable failures or issues with similarly aged cable, which would lead to targeted cable replacement programs in these areas*
- *Method of installation of cable (in duct or direct buried), which would lead to prioritizing the replacement of underground cable that is direct buried vs. in duct to mitigate reactive replacement costs and time*
- *Type of cable (XLPE vs. TRXLPE), which would lead to XLPE cable being replaced given the inherent deficiencies in its cable construction.*
- *Redundancy or reliability by examining if cables are looped already or on radial feeds that could lead to prolonged outages should equipment fail, which would lead to these projects being prioritized over other similar projects to fulfill additional system benefits.*

b) FHI has historically categorized events by standard OEB outage categories, including Defective Equipment. However, through searching historical outages FHI has come up with the below table on defective outages due to underground cables per year back to 2015.

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***
UG Cable Defective Outages	*4*	*1*	*1*	*2*	*2*	*4*	*2*	*5*	*3*

2-STAFF-15
Interrogatory:

Enterprise Resource Planning System (ERP)

Ref 1: Distribution System Planning, Material Investment Narrative, ERP Software Upgrade

Preamble:
Festival Hydro states that three vendors responded to the RFP for the ERP software upgrade which Festival Hydro is currently evaluating. Festival Hydro states that the costs will be finalized once a vendor has been selected and a contract is negotiated.

Festival Hydro states that the $1.75M budget for the ERP project was developed based on advice received from utilities implementing similar projects, with estimates ranging from $1.5M to $2.5M. Festival Hydro states that as it is slightly smaller than the comparison utilities, a budget estimate of $1.75M is being used.

Festival Hydro states that delaying the ERP upgrade poses a risk because the current software might lose vendor support, as Festival Hydro is one of the last clients using it in Canada. Festival Hydro states that a similar situation occurred with their CIS, where support ceased, leading to a rushed transition to a new system supported by contractors.

Question(s):

a) Please explain the basis for the project estimates from other utilities that ranged from $1.5M to $2.5M. Please confirm which utilities these estimates were from.

b) Please provide more details on how Festival Hydro arrived at the estimated budget of $1.75M for the ERP project based on utility size.

c) Please confirm if Festival Hydro has selected the vendor and finalized the cost of the ERP upgrade.

d) Please estimate the net financial impact of delaying the ERP upgrade and implications to its operations if the existing vendor is no longer able to provide these services.

Response:

a) Through informal industry discussions, FHI was aware that NT Power and Milton Hydro were both going through an ERP selection process. Both were ahead of FHI in the process and offered ranges of costs based on the submissions they had received at the time.

b) FHI anticipated that it would receive some of the same submissions as the utilities noted in a). FHI assumed that it may not select more complex systems due to the size of the utility and therefore selected an estimate on the lower end of the range. This estimate was used for the purpose of the initial Application, but the cost has been updated in these IRs.

c) *FHI is currently in contract negotiations with the selected solution provider, with a signed Master Service Agreement expected to be in place at the end of July.*

The total project implementation cost of the system is projected to be $1,354,813 including internal capitalized labour and third-party system integration costs. Annual licensing and support costs for the ERP solution are estimated to be $184,052. Costs have been updated in the applicable models based on current figures and included in this submission.

d) *The net financial impact of delaying the ERP upgrade is significant, but the impact extends beyond assigning a financial value. Multiple departments are faced with an excessive number of manual workarounds. Performance bottlenecks, system glitches, limited integration capabilities, rising maintenance costs, and struggles to comply with cybersecurity best practices, have been identified as on-going concerns. The legacy system struggles to synchronize with new applications and requirements increasing IT expenditures that would be better invested in innovation. Compliance with Canadian payroll rules is complex, and the legacy system lacks support for these requirements, creating the need for manual processes. In addition, the vendor used for ERP is the same vendor that FHI used for CIS who admittedly will no longer support regulatory updates regardless of if they are contractually obligated to do so. This has increased the risk of remaining with this vendor for any product.*

To extend the life of the current ERP, an external consultant would be required at a minimum cost of $100,000 per year. This would provide no guarantees of the system continuing to be viable as it would not address any new or updated regulatory or operational requirements.

EXHIBIT 3 – REVENUE

3-STAFF-16
Interrogatory:

Purchased kWh Load Forecast
Ref 1: Exhibit 3, page 9

Preamble:
Festival Hydro states that a COVID-19 flag was used to capture the lower usage for its commercial and industrial customers during March, April, and May of 2020.

Question(s):

a) Were Festival Hydro's customers also subject to province-wide shutdowns at other points in 2020 and 2021?

b) Has Festival Hydro attempted to model with additional months subject to a COVID-19 variable? If so, what were the results?

Response:

a) *Yes, FHI customers were subject to province-wide shutdowns at other points in 2020 and 2021.*

b) *FHI attempted to model with additional months subject to a COVID-19 variable, however, this resulted in a lower R Square value and a lower t Stat result. Please see the results of three different COVID-19 Flag scenarios attempted by FHI below:*

March 2020 – December 2021

Statistic	Value
R Square	68%
Adjusted R Square	66%
F Test	39.5
MAPE (monthly)	2.38%
T-stats by Coefficient Intercept	1.8
Heating Degree Days	6.7
Cooling Degree Days	8.3
Number of Days in Month	3.3
Spring/Fall Flag	- 2.5
Number of Work Days in Month	3.7
COVID 19 Flag	- 4.4

March 2020 – May 2020 & January 2021-March 2021

Statistic	Value
R Square	72%
Adjusted R Square	70%
F Test	47.7
MAPE (monthly)	2.35%
T-stats by Coefficient Intercept	2.0
Heating Degree Days	7.6
Cooling Degree Days	8.5
Number of Days in Month	3.4
Spring/Fall Flag	- 2.7
Number of Work Days in Month	4.0
COVID 19 Flag	- 6.1

March 2020 – June 2020

Statistic	Value
R Square	77%
Adjusted R Square	76%
F Test	62.8
MAPE (monthly)	2.2%
T-stats by Coefficient Intercept	2.1
Heating Degree Days	7.8
Cooling Degree Days	9.4
Number of Days in Month	3.8
Spring/Fall Flag	- 2.8
Number of Work Days in Month	4.6
COVID 19 Flag	- 8.5

3-STAFF-17
Interrogatory:

Load Forecast
Ref 1: Load Forecast Model, Load Forecast Summary
Ref 2: Exhibit 3, page 35

Preamble:
The Unmetered Scattered Load (USL) connections remained stable at approximately 230 connections from 2014 to 2020. In 2021 and 2022 they increased to 338 and 433. An increase in USL customers is attributed to reclassification of street light connections. In 2023, USL connections remained relatively stable at 435. The 2024 and 2025

connections are forecast based on geometric mean growth rate to increase to 467 and 501.

Question(s):

a) Is Festival Hydro aware of why USL connection growth would resume in 2024 and 2025?

b) As a scenario, please forecast the number of customers in Street Lighting and USL as if reclassification from Street Lighting to USL happened prior to 2014.

Response:

a) FHI anticipates the connection count in 2024 and 2025 will returned to a more levelled amount with incremental increases seen during the 2014-2020 period. FHI notes that the 10-year geometric mean growth rate was used in error in its original Application to forecast the 2024 and 2025 USL customer counts. FHI has updated this to exclude 2021 and 2022 from the Geo-mean average used to forecast the 2024 and 2025 USL connections. This change is reflected throughout the applicable models and included as part of this submission.

b) Please see response above.

3-STAFF-18
Interrogatory:

Load Forecast
Ref 1: Load Forecast Model, Rate Class Load Model

Preamble:
The Large Use rate class has an average kW/kWh ratio of 0.1528%. The ratio appears to OEB staff to be on a decreasing trend from 2014 to 2023. In 2014, 2015, 2016 and 2018 the ratio was above this level and in every year from 2019 to 2023, the ratio was below this level.

Question(s):

a) Is Festival Hydro aware of the reason for the decreasing kW/kWh ratio, or of any reason why it can be expected to return to the 10-year average?

b) As a scenario, please provide the kW forecast that would result from a more recent historic average.

Response:

a) FHI is not aware of the reason for the decreasing kW/kWh ratio as the factors for the decreasing are internal.

b) See the kW forecast based on a more recent 5-year average displayed below:

Year	Large Use	kW/kWh
2014	36,390	0.1553%
2015	39,140	0.1588%
2016	38,848	0.1543%
2017	36,858	0.1510%
2018	43,546	0.1619%
2019	41,926	0.1511%
2020	41,219	0.1499%
2021	41,849	0.1477%
2022	44,238	0.1500%
2023	43,002	0.1478%
2024	43,428	
2025	43,428	

Used	0.1493%
Average	0.1528%

FHI has updated the kW forecast based on the 5-year average and this update is reflected throughout the applicable models and included as part of this submission.

Upon review of the Large Use kW, FHI identified the kWh should also be reduced due to 3MW net metering project expected to come online July 1, 2024. FHI amended the 2025 kWh forecast for the Large Use rate classification by subtracting the estimated generation (kWh) for July to December 2025 from the Large Use weather corrected forecast. This reduction in kWh has also been reflected in the predicted purchases for 2025. These changes are included in the updated 2025 Load Forecast Model provided in this submission.

3-STAFF-19
Interrogatory:

Electric Vehicles and Heat Pumps
Ref 1: Exhibit 3

Preamble:
The written evidence and models make no reference to electrification through electric vehicles, heat pumps, or other emerging technologies.

Question(s):

a) Has Festival Hydro considered how EVs and Heat Pumps will affect load growth over the forecast period?

Response:

a) *While EVs and Heat Pumps are anticipated to increase as discussed in the DSP, FHI has not seen a substantial uptake in recent years and expects similar trends to occur through the Test Year with increases to occur more rapidly in later years. The load forecast included in the Application aligns with current historical trends.*

EXHIBIT 4 – OPERATING EXPENSES

4-STAFF-20
Interrogatory:

Executive Compensation
Ref 1: Exhibit 4, p. 10
Ref 2: Appendix 2-JD OMA Programs
Ref 3: Exhibit 4, Table 4-6 Executive Position Vacancies
Ref 4: Exhibit 4, p. 20
Ref 5: Exhibit 4, p. 31
Ref 6: Exhibit 4, p. 26

Preamble:
At reference 1, the application states that the cost of labour increased by $2.05M in the 2025 Test Year compared to the 2015 OEB-approved, representing 48% of the total OM&A increase.

At reference 2, the application states that the proposed budget for Executive Salaries and Expenses is $2.03M for the 2025 Test Year, representing an increase of $1.75M or 625% increase from the 2015 OEB-approved amount.

At reference 3, the application states that from 2020 to 2023 the following executive positions were accumulatively vacant in the range of 6 and 15 months: CEO, CFO, VP of Engineering and Operations, and VP of IT.

Table 5: Executive Position Vacancies

	Months Position Filled			
	2020	2021	2022	2023
CEO	6 of 12	9 of 12	12 of 12	12 of 12
CFO	12 of 12	9 of 12	12 of 12	12 of 12
VP of Engineering and Operations	12 of 12	9 of 12	12 of 12	12 of 12
VP of IT	12 of 12	6 of 12	4 of 12	5 of 12
Months Vacant	**6**	**15**	**8**	**7**

Based on Executive Salaries and Expenses provided in Chapter 2 Appendix, Tab 2-JD, OEB staff calculates the following year-over-year variances.

Table 6: Executive Salaries and Expenses from Chapter 2 Appendices, Tab 2-JD

	Executive Salaries and Expenses	Variance $	Variance %
Last Rebasing Year (2015 OEB-Approved)	$ 280,476	-	-

	Executive Salaries and Expenses	Variance $	Variance %
Last Rebasing Year (2015 Actuals)	$ 632,673	$ 352,197	126%
2016 Actuals	$ 686,040	$ 53,367	8%
2017 Actuals	$ 750,264	$ 64,224	9%
2018 Actuals	$ 870,444	$ 120,180	16%
2019 Actuals	$ 953,207	$ 82,763	10%
2020 Actuals	$ 983,543	$ 30,336	3%
2021 Actuals	$ 926,808	($56,735)	-6%
2022 Actuals	$ 1,063,300	$ 136,492	15%
2023 Actuals	$ 1,474,378	$ 411,078	39%
2024 Bridge Year	$ 1,783,566	$ 309,188	21%
2025 Test Year	$ 2,032,174	$ 248,608	14%

Based on the data provided in the table for Chapter 2 Appendix 2-K Employee Costs, OEB staff calculates average total compensation per employee for management and non-management staff, including the year-over-year change. Please see below.

Table 7: Per Employee Compensation Costs

	Last Rebasing Year 2015 - OEB Approved	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals
Average Total Compensation Per Employee (Salary, Wages, & Benefits)						
Management (including executive)	$ 127,182	$ 134,748	$ 144,428	$ 156,019	$ 163,186	$ 163,379
Non-Management (union and non-union)	$ 90,837	$ 93,977	$ 97,199	$ 100,574	$ 100,087	$ 102,415
Total	$ 99,722	$ 104,406	$ 110,187	$ 115,165	$ 115,477	$ 116,930

	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Average Total Compensation Per Employee (Salary, Wages, & Benefits)						
Management (including executive)	$ 166,211	$ 155,754	$ 167,033	$ 175,819	$ 212,452	$ 229,524
Non-Management (union and non-union)	$ 98,841	$ 100,583	$ 99,415	$ 102,586	$ 111,861	$ 115,602
Total	$ 114,882	$ 115,385	$ 117,124	$ 122,559	$ 139,295	$ 145,981

Table 8: Year-Over-Year % Change in Average Compensation on per Employee Basis

Year-Over-Year % Change in Average Compensation on per Employee Basis (Salary, Wages, & Benefits)	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals
Management (including executive)	5.95%	7.18%	8.03%	4.59%	0.12%	1.73%	-6.29%
Non-Management (union and non-union)	3.46%	3.43%	3.47%	-0.48%	2.33%	-3.49%	1.76%
Total	4.70%	5.54%	4.52%	0.27%	1.26%	-1.75%	0.44%

Year-Over-Year % Change in Average Compensation on per Employee Basis (Salary, Wages, & Benefits)	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	5 Year Historical Avg	Bridge Year & Test Year Avg
Management (including executive)	7.24%	5.26%	20.84%	8.04%	1.61%	14.44%
Non-Management (union and non-union)	-1.16%	3.19%	9.04%	3.34%	0.53%	6.19%
Total	1.51%	4.64%	13.66%	4.80%	1.22%	9.23%

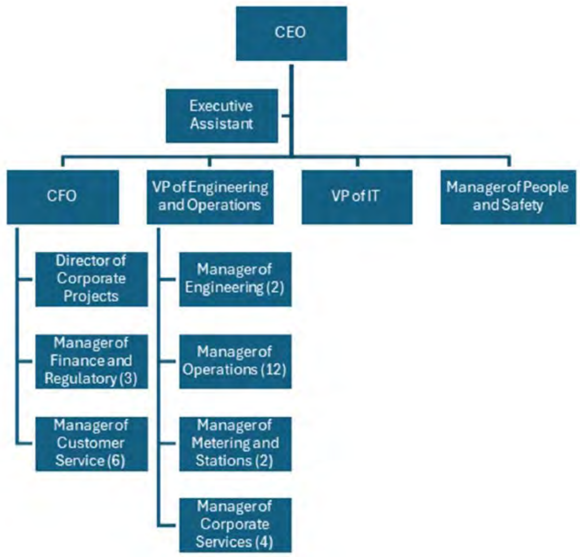
At reference 4, Festival Hydro states that an internal compensation review for non-union staff and an external compensation review[1] for executive staff were completed and the impacts were incorporated into the budget.

At reference 5, the application states that in 2022, Festival Hydro introduced an incentive payment program for the CEO and rolled out the program to the executive

[1] Exhibit 4, p. 29, the executive staff compensation review was completed in 2023 for 2024.

leadership team in 2023. The application states that the Board approves performance targets for the CEO position and that targets are aligned with Festival Hydro's Corporate Strategic Plan, its project plan, and its scorecard. Festival Hydro states that the CEO reviews industry benchmarks to determine performance incentives for the executive leadership team.

At reference 6, the application includes the following organizational chart:



Question(s):

a) Please confirm if the roles on the executive team include: Chief Executive Officer, Chief Financial Officer, Vice President of Engineering and Operations, and Vice President of Information and Technology? If not, please provide an accurate list.

b) Please provide the external compensation review for executive staff that were completed, including any reports and/or findings from this review.

c) Please explain how the results of the external compensation review for executive staff were used to inform compensation planning for the CEO and executive leadership, including any incentive payments.

d) The Executive Salaries and Expenses increase by 15%, 39%, 21%, and 14% in years 2022, 2023, 2024 and 2025, respectively, on a year-over-year basis. Please provide the drivers for the sharp increase in the Executive Salaries and Expenses in each of the years from 2022 to 2025, inclusive.

e) From 2015 OEB-approved to 2015 actuals, Executive Salaries and Expenses increased by $352K, representing a 126% variance. Please explain the variance.

f) The incentive payment program was introduced to the CEO in 2022 and later rolled out to the rest of the executive team in 2023. Festival Hydro states that a full staff complement is budgeted for 2024 and 2025.

I. In each year from 2023 to 2025, inclusive, please confirm the total actuals or budgeted incentive payments for the executive leadership team.

II. Festival Hydro states that the CEO uses industry benchmarks to determine the performance incentives for the executive leadership team. Please explain how the executive leadership team's incentive payments compare to industry benchmarks for the 2023, 2024 and 2025 years.

g) The application states that there were several vacancies in years 2020 to 2023 on the executive leadership team. From 2022 to 2023, the total months of vacancies slightly decreased by one[2] month while the Executive Salaries and Expenses increased by $411K, representing a 39% increase. Please explain why an increase of 39% in Executive Salaries and Expenses in 2023 is reasonable while total vacancies remained relatively flat in that year.

h) Please explain the process Festival Hydro's board uses to determine the CEO's performance targets.

i) Based on the calculation in Table 7: Per Employee Compensation Costs above, from 2023 to 2024, OEB staff calculates that the average management salaries on a per employee basis increased from $176K to $212K, representing a 20.8% increase. The total management salaries in that period increased by $440K. Please explain the drivers for the 20.8% increase.

j) Based on the calculation in Table 7: Per Employee Compensation Costs above, the historic average for years 2019-2023, management staff compensation on a per employee basis increased by 1.61% annually while it increased by 14.4% on average annually in the 2024 Bridge Year and 2025 Test Year. Please explain the drivers for the spike in management staff compensation on an employee basis in 2024 and 2025.

k) Please confirm which month and year the Chief Operating Officer position was removed.

l) Please fill in the table below for only employees on the executive leadership team.

	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)							
Executives							
Total Compensation (Salary, Wages, & Benefits)							

[2] The VP of IT role was vacant for 8 months in 2022 which decreased to 7 months in 2023.

Executives ($)							
Per Employee Salary and Wages							
Executives ($/employee)							

m) From the response to l) above, please explain any year-over-year variances for total compensation on a per employee basis greater than 10%.

Response:

a) *This is correct.*

b) *Please see Attachment 2 for Appendices A to C.*

c) *Please see Attachment 2 for Appendices A to C. At a high level, the external compensation review for FHI compared salaries of executives at other local distribution companies in Ontario targeting a job rate based on the market 50th percentile (P50) with a market salary range of P25 to P75 and includes cost of living increases. This was done in an effort to attract and retain top talent at FHI.*

d) *As noted in the table provided above, in 2021 there were several executive vacancies which caused an increase in salaries and expenses in 2022. In late 2022, again as noted, there was an executive compensation review that was completed which included incentive compensation that had not been in place previously. The CEO was eligible for incentive pay beginning in 2022 and the rest of the executive was eligible for incentive pay in 2023. This aligned executive total compensation more closely with the market. In 2024, all executive positions were filled for the full year as well as step increases for those who were not at the top of their pay structure. 3.5% wage increases were used for 2025 for executive pay similar to other management and non-management positions. The remaining increases are attributed to projected increases in benefit costs.*

e) *There are several reasons for this increase which were discussed in the Application.*

- In 2015 there was no Vice President of Information Technology. This position was added in 2017.
- Benefit costs, as noted in the Application increased over the period by 93%.
- The remaining increases relate to market competitive compensation based on external reviews.

f)

I. *2023 – 122,375*
2024 – 142,960
2025 – 147,965

II. Please see Attachment 2 for Appendices A to C.

g) Please see response in parts d) and e) above. A large portion of the increase relates to a market true-up of competitive compensation and the remaining increases are driven by benefit costs that are mostly out of the control of management.

h) In determining the CEO's performance targets, the FHI Board considers its design philosophy for annual pay-for-performance incentive plans, in that targets should be fair but not easily attainable; performance measures align with the organization's business strategy and are based on the achievement of annual goals and objectives and corporate performance KPIs. Performance targets relating to corporate objectives are weighted at 50% operational and 40% strategic, while targets related to professional development objectives are weighted at 10% of total weighting within the pay-for-performance incentive plan. The FHI Board's HR Committee rigorously reviews the CEO's annual pay-for-performance measures and associated targets and make recommendations to the full FHI Board.

i) There are several reasons for the increase:

The completion of the internal market-based study for all non-union and non-executive positions. Increases were reflected in this number.
- An increase in cost-of-living percentage for all non-union and non-executive positions based on the external inflationary environment.
- Substantial increases in benefit costs year over year.
- 2024 includes a full year of senior positions such as the VP of IT and Director of Corporate Projects which were only included for partial years in 2023.
- Step increases for several management positions; most managers are not at the top of their pay grids, so the annual increase is higher than cost-of-living alone.

j) The larger increase occurs in 2024; 2025 is aligned with the 2023 increase. This is for the same reasons noted in i) above.

k) The COO resigned as of December 31, 2014, and the position was not refilled.

l) See tables below.

	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)							
Executives	4	3.5	2.75	3.33	3.42	4	4
Total Compensation (Salary, Wages, & Benefits)							
Executives ($)	768,203	743,334	654,640	676,435	846,671	1,150,207	1,252,267
Per Employee Salary and Wages							
Executives ($/employee)	192,051	212,381	238,051	203,134	247,565	287,552	313,067
		11%	12%	-15%	22%	16%	9%

m) *2020 – Increase of 11% - the main increase related to the hiring of a new external CEO at a higher pay rate than previous employee, in addition there were annual increases for current executives as well as benefit cost increases.*
2021 – Increase of 12% - continued impact of the new CEO is built into this increase as well as the hiring of a new external CFO at the end of the first quarter. Benefit costs increased by 15% in this year.
2022 – Decrease of 15% - the main reason was the hiring of more junior executives in both VP of Engineering and Operations as well as VP of IT compared to the previous employees and therefore had lower costs.
2023 – Increase of 22% - this included replacement of VP of IT with more senior external individual, benefit cost increases as well as the introduction of incentive pay for all executives and wage impacts of the external market analysis.
2024 – Increase of 16% - this includes a full year of the new VP of IT; step increases from the external market analysis completed in 2023 as well as 13% increase in benefit costs.

4-STAFF-21
<u>Interrogatory:</u>

Unionized Staff Compensation
Ref 1: Exhibit 4, p. 26
Ref 2: Attachment 1-11, FHI Business Plan
Ref 3: Exhibit 4, p. 20

Preamble:
At reference 1, Festival Hydro states that for 2025 it applied a general cost of living increase for all labour related costs.

At reference 2, Festival Hydro states that labour increases are estimated at 3.5%.

At reference 3, Festival Hydro states that an internal compensation review was completed for non-union staff and incorporated into the budget.

Question(s):

a) What period does the current collective agreement cover?

b) Please provide the internal compensation review for non-union staff, including any reports and/or findings from this review.

c) Please explain how the internal compensation review for non-union staff informed the general cost of living increase applied to all labour related costs.

d) For 2025, please confirm if the rate used for the general cost of living increase to labour costs is 3.5%. If not, please confirm the rate used for the general cost of living increase. Please explain the process Festival Hydro used to determine that this rate was reasonable, including any benchmarking analysis completed with the industry.

e) Please compare the proposed cost of living rate increase for Festival Hydro employees with that of other utilities, if available.

Response:

a) May 1, 2021- April 30, 2025.

b) The 2023 Mearie Management Survey was used and is included in Attachment 3. In addition, FHI used published union data for comparable local utilities including Grandbridge, Kitchener, Waterloo, ERTH and London for positions that weren't included in the Mearie survey. FHI took the averages of P50 results (2023) for Mearie and the average of the local utilities (2023) to determine a comparable rate. This average was then compared to the top rate of each FHI position, anything higher than a 5% variance was amended, the remaining bands remained the same and received a cost-of-living increase for 2024. There were only five positions requiring a band change based on this review. One position was in excess of the average by greater than 5% and four positions were under the average by over 5%. Results of this analysis are included in the table below, positions and salaries have been removed due to personal information.

Title	% Differential	Outcome
Manager (1)	9.84%	Position's pay band was reduced to align with pay equity and individual is red circled
Manager (2)	-9.21%	Position's pay band was amended to align with pay equity
Manager (3)	-8.62%	Position's pay band was amended to align with pay equity
Finance (Non-Manager)	-23.45%	Position's pay band was amended to align with pay equity
Customer Service (Non-Manager)	-8.49%	Job desciption was reviewed and determined that there wasn't a comparable role in the external data. Current position was being compared to a Supervisor; job duties were less than that of other utilites. No change to pay band completed.

c) *The internal compensation review for non-union staff considered market rates for similar positions (Mearie, other LDC union contracts) compared to current rates for employees. If the position, with the 2024 cost of living increase of 3.5% was comparable to market, no change was made to the salary band. The salary bands for some positions were changed as noted above in part b).*

The actual cost of living percentage determination was not part of the internal compensation review and was based on external statistical guidance such as the Bank of Canada's economic reports, Stats Canada, Conference Board of Canada and Toronto Dominion Bank's quarterly economic forecast.

d) *Yes, 3.5% was used for the general cost of living increase. As noted in the Conference Board of Canada's Compensation Planning Outlook for 2024, the projected average non-unionized salary increases for 2024 is 3.5%. 2024 data was used in the budget as the most current information available.*

e) *2024 and 2025 Mearie data is not yet available. Most local comparators are currently in the process of completing negotiations that would include 2025. See below data that is publicly available based on current agreements.*

Utility	***Contract % for 2025***

Grandbridge	*2.75%*
Lakeland Hydro	*3%*
Ontario Power Generation	*3.25%*
Hydro One Inc.	*3.50%*
Hydro Ottawa	*3.25%*

4-STAFF-22
Interrogatory:

Engineering and Metering
Ref 1: Appendix 2-JC OM&A Programs
Ref 2: Exhibit 4, p. 26

Preamble:
At reference 1, the application states that OM&A spending for Engineering and Metering decreased by 43% in 2021 and then increased by 51% in 2022.

At reference 2, the application states that there was a Metering Administrator position added to this category and contract labour costs increased due to the need for meter repairs and maintenance due to aging smart meters.

Question(s):

a) Please explain the drivers for the changes in Engineering and Metering costs in 2021 and 2022.

b) Please confirm which year the Metering Administrator position was added.

Response:

a) In 2021, FHI had multiple staff vacancies or staff on leave for parts of the year which were the main driver for this reduction.

In 2022, FHI filled two of these vacancies and added the Metering Administrator position, which are the main drivers behind the increase over 2021.

b) The Metering Administrator position was added in 2022.

4-STAFF-23
Interrogatory:

Customer Service, Billing, Collecting and Software
Ref 1: Appendix 2-JC OM&A Programs
Ref 2: Exhibit 4, p. 9
Ref 3: Exhibit 4, p. 29
Ref 4: Exhibit 4, p. 34
Ref 5: Exhibit 4, p. 13

Preamble:
At reference 1, the OM&A budget for Customer Service, Billing, Collecting and Software is projected to increase to $1.64M in the 2025 Test Year relative to the five-year (2019-2023) average spend of $1.21M, representing a 35% increase.

At reference 2, Festival Hydro attributed increases in Billing, Collecting and Office costs to higher billing and collecting costs (i.e., higher costs for postage, paper and envelopes), bill print process costs, and office costs (i.e., office supplies, service charges, telephone and corporate communications, regulatory costs, and corporate events). Festival Hydro states that although outsourcing bill print process increased cost, it eliminated the need for in-house equipment to be re-purchased since it was at end of life and freed up time for billing and customer service staff to work on value added tasks.

At reference 3, the application states that part of the increase in the proposed budget for Customer Service, Billing, Collecting and Software was a result of outsourcing bill printing services in 2024.

At reference 4, the application states that a second bill coordinator is planned to be added in 2025 to assist with the new CIS and also support the main billing function as a backup.

At reference 5, the application states that Festival Hydro previously had an in-house IT full-time equivalent (FTE) to assist with the CIS and billing, but this work has been moved to Festival Hydro Services Inc. (FHSI), an entity that is wholly owned by the City of Stratford. There has also been a substantial amount of third-party work required for regulatory upgrades to the CIS.

At reference 4, the application states that Billing O&M unit costs are expected to increase from $31.40 in 2023 to $40.64 in the 2025 Test Year, representing a 29% increase and exceeding the 2018-2022 distributor average unit cost for this category.

Question(s):

a) Please provide a breakdown of the Customer Service, Billing, Collecting and Software actual costs for the 2019-2023 historical years and the forecasted costs for the 2024 Bridge Year and 2025 Test Year based on the following drivers noted in the application:
   a. Billing and collecting costs (i.e., higher costs for postage, paper and envelopes)
   b. Bill print process costs
   c. Office costs (i.e., office supplies, service charges, telephone and corporate communications, regulatory costs, and corporate events)

b) Please explain any year-over-year variances greater than 10% for the drivers in the response for all parts in a) above.

c) Please provide the cost for outsourcing the bill print process for 2024 and 2025.

d) Festival Hydro states that although outsourcing the bill print process increased costs, it eliminated costs related to replacing end-of-life in-house equipment and freed up time for billing and customer service staff to work on value-added tasks.
   I. Please estimate the cost Festival Hydro would have incurred if it had replaced the in-house equipment rather than outsource the bill print process on a best-effort basis.
   II. Festival Hydro states that outsourcing the bill print process freed up time for billing and customer service staff to work on value-added tasks. Please provide examples of value-added tasks.

e) Festival Hydro states that the CIS hosting cost is $86K and previously this service was provided by an internal staff. Please confirm which year Festival Hydro outsourced its IT and CIS services to FHSI. What was the net change in cost as a result of outsourcing IT and CIS services versus having internal staff complete this work?

f) Please confirm the range in budget for the new billing coordinator that is planned to be added in 2025.

g) Please explain the need to hire compared to continuing without hiring the second billing position given that the bill printing process and CIS work have both been outsourced, contributing to reduced overall workload for the existing billing/CIS staff.

Response:

a) *See table below.*

	2019	2020	2021	2022	2023	2024	2025
Billing and Collecting Costs	1,113,069	1,129,548	1,130,747	1,191,300	1,286,621	1,364,151	1,543,060
Bill Print						60,000	47,250
Office Costs	43,262	40,682	42,781	39,431	35,132	47,428	46,415
	1,156,331	1,170,230	1,173,528	1,230,731	1,321,753	1,471,579	1,636,724
Billing and Collecting Costs		1%	0%	5%	8%	6%	13%
Bill Print							-21%
Office Costs		-6%	5%	-8%	-11%	35%	-2%

a) *See table above.*

b) *See table above.*

c) *See table above.*

b) *Variances are highlighted in blue above.*

Billing and Collecting costs are projected to increase in 2025, partially because of the additional Billing Coordinator as well as inflationary increases for meter reading contracting costs, software increases and other labour increases such as step increases, cost-of-living, and benefit costs.

Bill Print costs are projected to decrease in 2025 as there were initial set up costs incurred in 2024 that are one-time expenses.

Office costs decreased in 2023 due to slightly inflated costs in 2021 and 2022 for additional costs related to COVID. Office costs increased in 2024 based on expected increases to telephone costs, insurance, and equipment maintenance. FHI has also budgeted a small amount of public relations costs related to e-billing campaigns.

c) See table above.

d)

I) Please see 4.0-VECC-35.

II) Enhanced Customer Service & Quality Control: With the reduction in time spent on printing and mailing bills, the billing coordinator can now focus on directly assisting customers with billing inquiries, resolving issues more swiftly and managing meter communication issues alongside the metering department effectively. More time can be devoted to ensuring the accuracy and quality of billing data before it is processed and sent to customers, reducing the likelihood of errors and improving customer satisfaction.

Process Improvement Initiatives: Freed from routine printing tasks, coordinators can actively participate in initiatives aimed at improving billing processes, such as implementing new software, creating and refining billing procedures in Jomar system, and enhancing overall efficiency.

e) This question is discussing two separate costs.

1) Hosting services are not completed by FHI or FHSI and are instead outsourced to JOMAR due to the cost that would have been incurred to host on site. This cost started to be incurred at the onset of CIS implementation in 2023. The cost to host on site was estimated to be $500K over a 5-year period to cover new servers, licenses, maintenance and internal management of the servers, therefore the outsourcing option was selected.

2) There was previously a full time IT position dedicated primarily to the CIS. This individual resigned in mid-2022 and this position was not replaced in FHI and *instead these services were outsourced to FHSI. The reason for this is the FHSI position can work on other IT related projects for FHI as well as tasks for the affiliate. The estimated savings for this change range from $20K-$30K in FHI depending on the CIS requirements in a given year.*

f) *This amount cannot be provided as it may influence negotiations with potential candidates. Consider reviewing similar roles at utilities with billing roles that are union negotiated and on the public record.*

g) *Some components of the billing process such as meter data management and verification have been brought in house with the transition to the new CIS while others such as bill print have been outsourced. As noted, FHI previously had a full time IT position primarily for CIS that was outsourced to FHSI, this is unrelated to the transition to the new CIS; regardless of the system, internal IT support is required and is unrelated to the need for the new billing position. As billing is a critical component of the utility's activities, it is prudent to ensure appropriate backup knowledge is available and quality data checks are complete to ensure accurate and timely bills. The current Manager of Customer Service previously held a billing position using the old system and could provide emergency assistance if required, but this is not the case using the new system. A second billing position is necessary but will also be able to provide backup customer and credit services if required in high call volume times, outages and backing up to vacations or other staff leaves.*

4-STAFF-24
Interrogatory:

Building Maintenance
Ref 1: Appendix 2-JC OM&A Programs
Ref 2: Appendix 2-JB OM&A Cost Drivers

Preamble:
At reference 1, OM&A spending for Building Maintenance increased by 22% in 2022 and is projected to increase by 55% in 2024. The proposed budget for Building Maintenance of $167K for the 2025 Test Year is 69% higher than the five-year average for 2019-2023 spending of $99K.

At reference 2, Property Maintenance costs increased from $6.9K to $66K from 2015 to 2016, representing an 861% increase.

Question(s):

a) Please explain the drivers for the increases noted above for Building Maintenance costs in 2022 and 2024 as well as the higher budget proposed for 2025.

b) Please explain the drivers for the increase in Property Maintenance costs in 2016.

Response:

a) *The main drivers for the increased Building Maintenance costs in 2022 were that FHI had to renew their cleaning contract through a competitive RFQ process, and the lowest bidder was approximately $10,000 more than historical. The other main drivers were a structural engineering firm that was hired to review and replace FHI's roof access kits, and plumbing costs to maintain and flush a damaged sewer pipe.*

   The main driver for the increased Building Maintenance cost in 2024 was the hiring of a new FTE within the company to assist in overseeing and managing FHI's various lands and buildings.

   The higher 2025 budget is due to inflationary increases from the 2024 budget and is expected to remain consistent over the forecast years.

b) *The property maintenance costs didn't increase from $6.9K to $66K from 2015 to 2016. Table 2-JB shows the change in that grouping year over year. This means that the variance in this grouping of accounts changed by this amount, this increase is 44% which is still significant in one year. The majority of the variance is due to how allocations were completed in 2015. There was an allocation credit in 2015 which lowered the overall grouping of accounts, most of which relate to third party services for janitorial, HVAC inspections and third-party repairs. These costs were previously allocated to contract labour and operations. There were also changes in the historical period for how property taxes were allocated. The actual increase for similar expenses from 2015 to 2016 is approximately 10K.*

4-STAFF-25
Interrogatory:

Administration, Third Party, Software & Communications
Ref 1: Appendix 2-JC OM&A Programs
Ref 2: Exhibit 4, p. 21

Preamble:
At reference 1, OM&A spending for Administration, Third Party, Software and Communications is projected to $3.15M in the 2025 Test Year from the 2015 OEB-approved budget of $1.37M, representing a $1.77M increase or 129%.
Festival Hydro states that the following are the drivers of the increase:

- $1.2M – Step and inflationary increases
- $200K – Contract and third-party costs for legal and audit
- $215K – Software costs for ERP, board software, and other cyber security related Software as a Service and service models

- $130K – Costs related to training, education, travel, communications and public relations, office supplies, corporate costs and events

Question(s):
Please breakdown the $1.2M step and inflationary increases by executives, management staff (excluding executives) and non-management staff.

Response:
Executive (note that there were three Executives in 2015 and four in 2025) - $923K
Management - $201K.

Non-Management (in 2015 there was a cashier and coop that are no longer in 2025) - $76K.

4-STAFF-26
Interrogatory:

Stations O&M
Ref 1: Appendix 2-JC OM&A Programs
Ref 2: Exhibit 4, p. 27
Ref 3: Distribution System Plan, p. 7

Preamble:
At reference 1, OM&A spending for Stations O&M increased by 33%, 44%, 24% and 55% in 2018, 2021, 2022, and 2023, respectively, on a year-over-year basis. Stations O&M is projected to increase by 32% in 2025.

At reference 2, Festival Hydro explained that the variance in Stations O&M from the OEB-approved in 2015 and the 2025 Test Year is a result of higher allocation of employee time to Stations O&M, annual step and inflationary increases, and increased contract labour costs.

At reference 3, Festival Hydro states that the Voltage Conversion Program is expected to reduce O&M costs associated with maintaining and operating 4kV substations as Festival Hydro is retiring its last two 4.16 kV substations. Festival Hydro anticipates the voltage conversion project to finish in 2033

Question(s):

a) Please explain why Stations O&M is expected to increase in 2025 although Festival Hydro plans on retiring two of its substations.

b) Please confirm which year Festival Hydro anticipates it will start realizing the reduced Stations O&M costs from the voltage conversion project.

Response:

a) *FHI's Stations O&M costs include both the 4kV substations, as well as the FHI owned transformer station. In 2025, the increase is due to biennial maintenance needing to be completed at the transformer station, as well as budgeting for testing that is coordinated by the transmitter and is scheduled to occur in 2025.*

b) *FHI anticipates that beginning in 2029 it will start realizing some reduced Stations O&M costs that are attributed to the 4kV substations, as in 2028 it is anticipated that the first 4kV substation will be brought out of service.*

4-STAFF-27
Interrogatory:

Transformer Station Equipment - Operation Labour
Ref 1: Appendix 2-JD OM&A Programs
Ref 2: Exhibit 4, p. 40-41

Preamble:

At reference 1, OM&A spending for Transformer Station Equipment - Operation Labour increased by 291%, 611%, and 196% in 2021, 2022, and 2023, respectively on a year-over-year basis.

At reference 2, the application states that control room monitoring for the transformer station is outsourced to London Hydro.

Question(s):

a) Please explain the drivers for the increases noted above for 2021, 2022 and 2023.

b) Please confirm which year the control room monitoring for the transformer station was outsourced to London Hydro.

c) Please confirm if the costs for control room monitoring for the transformer station that is outsourced London Hydro is expected to offset another OM&A program. If yes, please confirm the OM&A program and the years the offset is expected / has been realized.

Response:

a) *The cost increases from 2020 to 2021 were for staff time to complete switching at the station for planned work, which did not occur in 2020.*
The cost increase for 2022 and 2023 was due to the hiring of a new FTE, whose non-capital time goes to this account.
This FTE was hired partway through 2022, which is why 2023 is higher then 2022. This number is expected to remain stable in future years.

b) *Control room monitoring has been outsourced to London Hydro since 2013.*

c) *Control Room Monitoring has been outsourced to London Hydro since the transformer station was in service. While this does not offset any current OM&A programs, it has offset the need for FHI to manage their own control room and the associated costs.*

4-STAFF-28
Interrogatory:

Administration, Third Party, Software & Communications
Ref 1: Appendix 2-JC OM&A Programs
Ref 2: Exhibit 4, p. 27

Preamble:
At reference 1, the application states that OM&A spending for Administration, Third Party, Software & Communications increased by 24% and 22% in 2016 and 2018, respectively, on a year-over-year basis.
At reference 2, the application states that the increase of spending from 2015 OEB approved to the 2025 Test Year for Administration, Third Party, Software & Communications was partly due to Festival Hydro hiring two new positions within the finance, HR, and IT group – the Director of Projects and Executive Assistant.

Question(s):

a) Please explain the drivers for the cost increases noted above for Administration, Third Party, Software & Communications specifically for 2016 and 2018.

b) Please confirm which year the Director of Projects and Executive Assistant were hired.

c) FTE headcount has remained flat during the 2015 to 2025 period. Please confirm what roles were removed in order to add the Director of Projects and the Executive Assistant roles.

d) Please explain any increased work/projects and plans that requires the hiring of a new Director of Projects and Executive Assistant.

e) Please explain the need to hire a new Director of Projects and Executive Assistant compared to continuing without hiring these positions.

Response:

a) *For 2016 please see explanation on page 20 of Exhibit 4 under third party services.*

   For 2018 please see the first explanation on page 19 of Exhibit 4 under contract services, in addition there were higher costs associated with external management and legal services in that year.

b) Both were hired in 2023.

c) There were several movements and position changes over the ten-year period. For example, there was previously a Cashier and a Customer Service Secretary, these positions transitioned to Customer Service Representatives with retirements or departures of other staff to meet more current needs and trends.

Two positions that were eliminated with no similar role replacing them are:

The Chief Operating Officer was included in the last Application but resigned as of December 31, 2014. This position was not replaced.

The Information System Analyst resigned in 2022 and this position was outsourced to FHSI.

d) Director of Projects – The Director of Projects is responsible for the management and execution of current large corporate projects such as building renovations, Customer Information System (CIS), Enterprise Resource Planning (ERP), and Advanced Meter Infrastructure (AMI). The Director is responsible for the successful completion of projects by providing leadership, strategically managing risk, monitoring finances and making sure that each phase of the project starts and ends on schedule. Typically, the Director, Corporate Projects would manage projects with cost thresholds on average of greater than $300k or smaller as assigned by the CFO. FHI estimates that large corporate projects will continue in the forecast period and beyond with the increase in electrification and DERs. The current individual holds both a Professional Engineer designation and Project Management Professional certification. This position may also assist with short- and long-term Executive succession planning.

The responsibilities that this role is taking on would have had to be outsourced for the large projects identified above as the time commitment required would not be available by other roles. FHI believes that having internal knowledge of both systems and employees increases efficiencies within the projects.

Executive Assistant – The Executive Assistant's primary duties and responsibilities include the following:
- serve as a liaison between the President and CEO and various internal and external stakeholders
- respond to inquiries on behalf of the President and CEO, including those of a highly confidential and critical nature
- organizing and assisting with all internal and external corporate communications and records management
- provide direct administrative support to the Executive Leadership Team

- ensure the corporate governance framework is properly designed, implemented, and maintained, and Board policies are reviewed and updated as required
- schedule Board and Committee meetings, assist in agenda development, assist in developing and distributing all committee and Board minutes and reports
-As well as many other tasks as they arise.

Prior to 2023, FHI outsourced some administrative and governance assistance from FHSI. The amount of time required by Executives to assist with administrative and governance related tasks was increasing and could no longer be supported by FHSI, so this position was created. FHI believes that the Executive Leadership Team and specifically the CEO can better use their time on strategic and leadership tasks as opposed to administrative tasks. While there is a higher cost, there is a substantial efficiency benefit.

e) As noted in part d) above these roles would have been fully or partially outsourced and have created internal efficiencies for the Executive Leadership Team and other management.

4-STAFF-29
Interrogatory:

Contract labour and services
Ref 1: Exhibit 4, p. 12
Ref 2: Appendix 2-JC OM&A Cost Drivers

Preamble:
At reference 1, that application states that from the 2015 OEB approved to the proposed 2025 Test Year, contract labour and services costs increased by $666K, representing a 15.7% increase.

Question(s):

a) Please breakdown the $666K increase into two categories: 1) costs that were previously internal labour costs, and 2) new or higher contract labour costs.

b) From the answer to a) above, for any costs that were previously internal labour costs, please confirm the OM&A programs these costs are expected to offset.

c) From the answer to a) above, for any new control labour costs, please explain the need to contract the work compared to hiring an internal resource.

Response:

a) See table below.

New or Higher Contract Labour Costs	
SCADA	68,185
TX Oil Sampling and Maintenance	89,100
Meter Reading	34,031
Vehicle Maintenance	107,673
Operations Maintenance	35,021
	334,010
Partially Previously Internal Labour	
Metering	123,189
Tree Trimming	34,338
IT Services	124,356
Regulatory	50,000
	331,883

b) *Metering – part of this expense would have gone to labour and burdens, some of this cost was always contracted.*
IT Services – part of this expense would have gone to labour and burdens and billing costs, some expense is 'net new'.
Tree Trimming – part of this cost was previously done by operations staff which was replaced by alternate work.
Regulatory – part of this work was completed by finance manager but work and expertise required in this area has increased as well as increased workload in finance department.

c) *Metering – three phase work requires two meter technicians so a second position would have needed to be hired. After the meter technician retired, this work was outsourced.*
IT Services – see responses to 4-Staff-23 (e) and 4.0-VECC-27.
Tree Trimming – Operations staff were better utilized for capital and distribution system operations work.
Regulatory – specialized expertise in this area was required but not a full FTE worth so a resource was shared with ERTH Power.

2-STAFF-30
Interrogatory:

Regulatory Costs
Ref 1: Chapter 2 Appendices, Tab 2-M

Preamble:
The application includes the following table for one-time regulatory costs.

Table 9: Regulatory One-Time Costs

	Regulatory Costs (One-Time)	Last Rebasing (2015 OEB Approved)	Last Rebasing (2015 Actual)	Sum Of Historical Years (2016-2023)	2024 Bridge Year
1	Expert Witness costs				
2	Legal costs	75,000	45,000	1,715	98,285
3	Consultants' costs	58,250	95,400	136,460	138,540
4	Intervenor costs	50,000	100,000	0	100,000
5	OEB Section 30 Costs (application-related)				20,000
6	Incremental operating expenses associated with staff and other resources	12,750	41,600	56	4,944

Question(s):

a) Please confirm the year-to-date costs for legal and consultants for one-time regulatory costs.

Response:

a) Year to date legal costs for one-time regulatory costs total $25,306 and consultant costs total $144,640.

4-STAFF-31
Interrogatory:

Software as a Service
Ref 1: Attachment 1-11, FHI Business Plan
Ref 2: Exhibit 4, p. 21

Preamble:
At reference 1, Festival Hydro states that there has been a shift from on-premise IT solutions to Software as a Service (SAAS) models. Festival Hydro states that some service provides no longer offer on-premise solutions which limits vendor and product options to those preferring on-premise solutions.

At reference 2, Festival Hydro states that in the 2025 Test Year, Software Support and Maintenance costs are expected to increase by $162K due to cyber security related software and SAAS costs related to the planned ERP software.

Question(s):

a) Please breakdown the $162K increase in Software Support and Maintenance costs by cyber security software and SAAS costs related to the ERP software.

b) Please confirm if these OM&A costs related to the planned ERP software project are one-time or recurring costs.

c) Please explain any cost savings as a result of moving to the SAAS model which Festival Hydro would otherwise being incurring with on-premise solutions.

d) Please complete the following table on spending between on-premise and cloud/SAAS.

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On Premise											
	Capex	$									
	OM&A	$									
SaaS											
	Capex	$									
	OM&A	$									

Response:

a) *As identified in 2-Staff-15 the final annual operating costs related to the ERP are expected to be $184,052 - $92,552 for licensing costs and $90,000 for support. The support costs for 2025 ($45,000) were only included for half of the year in the Test Year as FHI anticipates it will go live mid-year. Cyber security are expected to increase by approximately $25K.*

b) *These costs are recurring. All one-time costs are included in the capitalized portion of implementation.*

c) *FHI believes that SAAS should not be used as a blanket term to include software subscriptions. FHI has seen IT and cybersecurity vendors move to a subscription model for licensing which moves costs from CAPEX or OPEX but does not move the solution to a fully SAAS based deployment.*

FHI focuses on ensuring efficiencies are realized when adopting a 100% SAAS solution. Benefits are typically generated from the consolidation of specialized infrastructure. For example, CIS and ERP have been hosted on a on-premise IBM-based hardware platform which requires dedicated vendor support and maintenance contracts. Once CIS and ERP are fully migrated this platform can be retired which will result in savings which offset some of the cost of the new system.

It is also important to note that cost avoidance has been another driving factor in the move to SAAS. For example, business continuity was never considered with Microsoft Exchange on-premise. By moving to Office 365, FHI gained resilience without having to incur licensing hardware expense to have high availability deployed on-premise. This would have added $15,000 in year expense.

d) *FHI believes the following table better represents how we allocate IT spending. Note – the SAAS row details the portion of expense directly related to a hosted cloud system:*

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SAAS	$0	$4,000	$9,000	$24,000	$42,500	$42,500	$46,000	$46,000	$46,000	$46,000
Capex - Hardware	$60,193	$275,020	$176,561	$290,629	$193,069	$296,636	$288,892	$366,657	$381,323	$396,576
Capex - Software	$216,420	$66,063	$267,546	$446,552	$1,046,165	$733,247	$72,223	$91,664	$95,331	$99,144
Subscription (OM&A)	$18,530	$26,100	$26,100	$51,850	$88,445	$135,902	$135,902	$142,094	$142,094	$142,094

*** Capex – Software covers both licensing where appropriate and the cost of implementing all software projects, regardless of how the software is delivered. The implementation costs are comprised of both internal labour and consultant time.*

There are additional OM&A costs not included in the table above for ‘general software OM&A’ for expenses such as ongoing support and maintenance costs.

EXHIBIT 5 – COST OF CAPITAL

5-STAFF-32
Interrogatory:

Cost of Capital
Ref 1: EB-2024-0063, Notice, March 6, 2024
Ref 2: EB-2024-0063, OEB Letter, April 22, 2024

Preamble:
On March 6, 2024, the OEB commenced a hearing (EB-2024-0063) on its own motion to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and Ontario Power Generation Inc. The methodology for determining the OEB's prescribed interest rates and matters related to the OEB's Cloud Computing Deferral Account will also be considered, including what type of interest rate, if any, should apply to this deferral account.

On April 22, 2024, the OEB approved the final Issues List for this proceeding, including the following two issues, amongst other issues:

18. How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?

19. Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

Question(s):

a) Please confirm that the applicant proposes to implement the outcomes from the OEB's generic cost of capital proceeding, including what the OEB decides with respect to implementation. If this is not the case, please explain.

Response:

a) *If the OEB determines that the new cost of capital parameters should apply to FHI regardless of where it is in the rate term (i.e., issue 18 and 19), FHI will comply with the OEB's determinations in that regard.*

5-STAFF-30
Interrogatory:

Long-Term Debt
Ref 1: Exhibit 5, page 5-6, 10

Preamble:
Festival Hydro entered into an interest rate swap agreement with RBC on a notional principal of $5,000,000. The effective date of the loan is December 31, 2024 (Swap loan #2), and the total rate is 4.02%

Festival Hydro plans to enter into an additional 10-year interest rate swap agreement with RBC in 2025. The estimated interest rate is 6.05%.

Question(s):

a) Please confirm the interest rate that Festival Hydro applied for Swap Loan #2 in year 2024.

b) What are the interest rates on the actual loans with RBC? Please confirm if it is a variable rate or fixed rate.

c) Please provide more information on Festival Hydro debt strategies. Are the swap loans for hedging purposes?

d) What is the estimated interest rate on the new loan that Festival Hydro projects for 2025?

Response:

a) *As noted on page 5 of Exhibit 5, FHI entered into an interest rate swap agreement with RBC on a notional principal of $5,000,000. The effective date of the loan is December 31, 2024, and was drawn on as short-term revolving debt until this date. The short-term revolving debt is based on 30-, 60-, or 90-day CORRA rates at FHI management discretion. In 2023, 2.5M was drawn on at the revolving rate, in 2024, the full $5M was drawn on. As of December 31, 2024, the SWAP will begin at the interest rate of 4.02%.*

b) *Bank Loan – 2.62% - Fixed, Matures November 25, 2025*
Swap Loan #1 – 4.74%, Fixed rate for 10 years until May 2033, full loan matures May 31, 2038
Swap Loan #2 – Currently variable revolving debt until December 31, 2024, when it will become fixed at 4.02% for 10 years. The variable revolving rates have been averaged in Table 5-3 for 2023 and 2024.

c) *FHI's debt strategy has changed in recent years. Currently, FHI assesses short- and long-term financing needs through the budget process and then determines when financing is required. If the external rates are favourable as they were in 2021, FHI will lock into an interest rate swap with a forward fix date so that funds aren't borrowed ahead of when they are required. This cannot be done all of the time however, as in 2025, where funds are required for the capital plan, and it may not be the most ideal interest rate environment. Swaps are used for hedging and predictability of costs.*

d) *As noted on page 5 of Exhibit 5, FHI has projected a loan amount of $5M and estimated an interest rate of 6.05%, based on an RBC estimate as of February 16, 2024.*

EXHIBIT 6 – REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY

6-STAFF-33
Interrogatory:

Ref 1: Exhibit 6, page 14

Preamble:
Festival Hydro states that, at the time of filing its application, the distributor has not filed its 2023 corporate income tax returns. Festival Hydro does not expect significant changes between the final 2023 corporate income tax returns and the 2023 forecast income tax provision. Festival Hydro will provide a copy of the final 2023 tax returns as soon as they are available and update the Board's Income Tax/PILs Work Form model for the 2023 Actuals.

Question(s):

a) Please provide a copy of the 2023 filed tax returns, if available.

b) Please provide an updated PILS work form including 2023 actuals.

Response:

a) *The 2023 Tax Return is included in Attachment 4.*

b) *The PILs model has been updated and included as part of this submission.*

6-STAFF-34
Interrogatory:

Ref 1: FHI_2025_Test_year_Income_Tax_PILs_1.0_20240426_20240508.xlsm
Ref 2: FHI_2025_Filing_Requirements_Chapter2_Appendices_1.0_ 20240508.xlsm, tab 2BA

Capital Additions			
Year	**Appendix 2BA**	**PILS**	**Difference**
2024	7,497,827	7,716,940	(219,113)
2025	7,409,350	7,736,538	(327,188)

Question(s):

a) OEB staff notes that the capital additions at reference 1 and reference 2 are different. Please reconcile the difference and update the schedules as necessary.

Response:

a) *The PILs Workform has been updated and agrees to Appendix 2-BA. The updated PILs Workform has been included in this submission.*

6-STAFF-35
Interrogatory:

Ref 1: FHI_2025_Test_year_Income_Tax_PILs_1.0_20240426_20240508.xlsm
Ref 2: FHI_2025_Filing_Requirements_Chapter2_Appendices_1.0_ 20240508.xlsm, tab 2BA

	Depreciation		
Year	**Appendix 2BA**	**PILS**	**Difference**
2023	2,526,371	2,609,205	(82,834)

Question:

a) OEB staff notes that the depreciation expense at reference 1 and reference 2 are different for 2023. Please confirm the amount of capital additions and update the schedules or explain the difference.

Response:

a) The difference is due to depreciation of deferred revenue being included in the calculation of rate base and included in reference 2. Deferred revenue is not depreciated in PILs in reference 1. The second difference is due to non-distribution assets are not included in rate but is depreciated in PILs. The depreciation in reference 1 for 2024 and 2025 has been updated to also include depreciation of non-distribution assets.

6-STAFF-36
Interrogatory:

Ref 1: Exhibit 6, page 19-20

Preamble:
Festival Hydro pays property taxes to the City of Stratford and the Township of Seaforth for its Service Centre and Administration premises and the Municipal Substations and Transformer Stations. Property taxes for the 2015 Board Approved, Historical years 2015-2023, the 2024 Bridge Year and the 2025 Test Year are reproduced in the table below.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Property Tax	96,756	38,017	55,726	82,847	74,054	135,993	126,934	126,868	151,191	143,937	154,677
% Increase		**-155%**	**32%**	**33%**	**-12%**	**46%**	**-7%**	**0%**	**16%**	**-5%**	**7%**

Question(s):

a) Please explain the nature of any increases +/- 10% compared to the previous year.

Response:

a) *There was an error in the original table. There was no change to 2024 and 2025. Please see the attached table:*

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Property Tax	109,582	111,916	107,648	112,868	107,174	126,752	118,441	121,539	145,863	143,937	154,677
% increase		2%	-4%	5%	-5%	18%	-7%	3%	20%	-1%	7%

The increase in 2020 related to a reassessment at FHI's Wright Blvd. location which included partial backdated billings. In 2023, the Administration Building was reassessed which caused an increase.

EXHIBIT 7 – COST ALLOCATION

7-STAFF-37
Interrogatory:

Weighting Factors
Ref 1: Exhibit 7, page 7

Preamble:
Festival Hydro states that an analysis of Accounts 5315 – 5340 except 5335 was conducted to determine the weighting factors for billing and collection.

Question(s):

a) Please provide the analysis that supports the weighting factors used.

Response:

a) *FHI calculated a meter data management cost per customer. The cost per customer were applied to the 2022 customer counts to determine the cost per rate class. FHI also calculated the total number of bills per rate class per year. Finally, FHI assessed collections cost and complexity and the need for manual intervention. Tables depicting FHI's analysis are below:*

Meter Data Management Costs:

Billed Month	MDM/R Billed Smart Meters	Interval Meters
January	$ 4,731	$ 6,875
February	$ 4,729	$ 6,604
March	$ 4,728	$ 6,538
April	$ 4,722	$ 6,376
May	$ 4,721	$ 6,893
June	$ 4,719	$ 6,365
July	$ 4,723	$ 6,347
August	$ 4,721	$ 6,341
September	$ 4,720	$ 6,339
October	$ 4,710	$ 6,344
November	$ 4,713	$ 6,344
December	$ 4,593	$ 6,449
Total Cost	**$ 56,531**	**$ 77,815**

Meter Data Management Cost per Customer:

	Total Cost	Cost Per Customer
Residential & GS<50 kW	$ 53,705	$ 2.46
GS 50 to 4,999 kW, Large Use,, Streetlights &WMP	$ 80,642	$ 364.90

Meter Data Management Cost per Rate Class:

	2022 Customer Count	Cost Per Rate Class
Residential	19,756	$ 48,529
GS<50 kW	2,107	$ 5,176
GS 50 to 4,999 kW	210	$ 76,628
Sentinel Lights	36	
Streetlights	9	$ 3,284
Unmetered Scattered Load	16	
Large Use	2	$ 730
Total	22,136	

Total Bills Per Rate Class:

Rate Class	Number of Bills
Residential	237,072
GS<50 kW	25,284
GS 50 to 4,999 kW	2,520
Sentinel Lights	432
Streetlights	108
Unmetered Scattered Load	192
Large Use	24
Total	265,632

Weightings Analysis:

Rate Classification	Weighting	Analysis
Residential	1	Majority of Customers, all smart meters, minimal intervention when meters functioning appropriately. More collections, but line crew not required for disconnects (contractor)
GS<50 kW	1.32	Second largest group of customers, all smart meters, minimal intervention when meters functioning appropriately. Higher collections time costs and require line crew for some disconnection. More difficult to collect bad debt.
GS 50 to 4,999 kW	3.16	Utilismart costs, some Savage costs (MIST meter intervention), low volume of customers, higher costs (meter + some LTE connection costs). Collections costs are lower, but could require line crew if needed
Sentinel Lights	0.72	No collections cost. Based on connections - manual update.
Streetlights	0.72	Utilismart costs only, manual updating of connections when changes are completed, no collections.
Unmetered Scattered Load	0.72	Manual updating of connections when changes completed, no collections.
Large Use	2.2	Utilismart costs, no Savage costs, single customer, higher meter cost, virtual meters (2) complex bill, Class A, no collection activity to date.

7-STAFF-38
Interrogatory:

Weighting Factors
Ref 1: Cost Allocation Model, sheet I7.1 Meter Capital, sheet I7.2 Meter Reading.

Preamble:
For each of the rate classes below, Festival Hydro has entered more meters on sheet I7.1, than it has indicated as being read on sheet I7.2.

	I7.1 Meter Capital (total meters)	I7.2 Meter Reading (total reads)
Residential	20,580	20,541
GS < 50 kW	2175	2,146
GS 50 – 4,999 kW	220	209

Question(s):

a) Please confirm or correct the numbers in the cost allocation model.

b) Please explain the situation that results in meters being assigned to rate classes, but no associated meter reading.

c) If these meters are not installed, please indicate why they are assigned to specific rate classes.

d) If these meters are installed, please explain why they don't need to be read.

Response:

a) FHI confirms the number of meters.

b) All differences are due to meters that have been pulled for various reasons (reverification, no longer a service), but are still in useable condition.

c) The meters that are not installed are assigned to the rate class that they were assigned to when they were installed.

d) N/A.

7-STAFF-39
Interrogatory:

Demand Allocators
Ref 1: Cost Allocation Model, sheet I8 Demand Data

Preamble:
The Demand Data worksheet reflects that the Street Light and Sentinel Light rate classes do not have any load connected to the secondary voltage system. The demand data worksheet also reflects that the Sentinel Light 1 NCP is served using line transformers, but the Sentinel Light 4 NCP and 12 NCP do not include any usage of line transformers.

Question(s):

a) Please explain the counter-intuitive situation where Street Light and Sentinel light do not appear to make use of secondary assets or correct the model.

b) Please correct the model with respect to use of line transformers by Sentinel Lights.

Response:

a) The Cost Allocation Model has been corrected to reflect all Sentinel Light customers and three Street Light customers making use of secondary assets. The revised model has been included in this submission.

b) *The Cost Allocation Model has been updated with Sentinel Light 4NCP and 12NCP including usage of line transformers. The revised model has been included in this submission.*

EXHIBIT 8 – RATE DESIGN

8-STAFF-40
Interrogatory:

Fixed / Variable Split
Ref 1: Exhibit 8, pages 4-5

Preamble:
Festival Hydro is proposing to maintain the current fixed/variable proportions for all rate classes, even those where it increases a fixed charge above the ceiling (defined as the minimum system with peak load carrying capability adjustment in cost allocation model).

Question(s):

a) As a scenario, please provide the variable charges that would result from keeping the fixed charges for the GS < 50 kW, GS 50 – 4,999 kW, and Large Use rate classes at the current level, and where the fixed charge would be limited to the ceiling ($10.36 in the model filed April 26) for the USL rate class.

Response:

a) *See table below for variable charges resulting from keeping the fixed charge for the GS < 50 kW, GS 50 to 4,999 kW, and Large Use rate classes at the current level, and where the fixed charge would be limited to the ceiling for the USL rate class:*

Rate Class	Fixed Charge	Variable Charge
General Service < 50 kW	$ 36.86	0.0219/kWh
General Service 50 to 4,999 kW	$ 273.56	3.6543/kW
Large Use	$ 13,084.05	2.2528/kW
Unmetered Scattered Load	$ 10.36	0.0147/kWh

8-STAFF-41
Interrogatory:

Retail Transmission Service Rates
Ref 1: Exhibit 8, pages 8-9
Ref 2: RTSR Workform

Preamble:
Festival Hydro states that it amended the RTSR for gross load billing for two customers.

Question(s):

a) Please detail the amendment to the RTSR and indicate whether the gross load billing quantities are included in both the RRR volume, and the Wholesale purchase volumes.

b) Please confirm which year of historic data is used for the RRR customer volumes.

c) Please confirm which year of historic data is used for the Historic Wholesale volumes.

Response:

a) FHI has not amended the RTSR for gross load billing as the RTSR rates are based on 2023 transmission charges.

b) FHI used 2023 for the RRR customer volumes.

c) FHI used 2023 for the Historic Wholesale volumes.

8-STAFF-42
Interrogatory:

Specific Service Charges
Ref 1: Exhibit 8, page 11

Preamble:
The specific service charges for Service Call – Customer Owned Equipment, and Service Call – After Regular Hours are proposed to have the charges changed from the current charges of $30 and $165 respectively to both being Time & Materials.

Currently, Festival Hydro has a $15 Income Tax Letter charge, and it states that based on how this is used in current practice, Festival Hydro is requesting that this be called Bill Copy Charge with no change to the amount.

Question(s):

a) Please indicate the number of times each specific service charge has been applied in 2023.

b) If Festival Hydro is able, please provide details on typical costs of performing these services.

c) Please explain the current practice for the Income Tax Letter charge and why revising this to Bill Copy Charge is appropriate.

Response:

a) *In 2023, the $15 charge was billed to customers a total of 30 times throughout the year.*

The specific service charges for Service Call – Customer Owned Equipment, and Service Call – After Regular Hours were not charged in 2023. For the Customer Owned Equipment service charge, when looking at the incremental administrative cost and time to track, bill, invoice and collect this charge, it does not cover the amount that would be recouped from these charges. For after hours, the 2023 calls that were not for customer equipment were for an FHI issue, or emergency locates, which FHI would not charge for.

b) *Typical costs on performing these services depend on the time of day, location and type of service.*

For a Service Call – Customer Owned equipment, this can range from $0 (as once yearly, per customer, FHI completes disconnects free of charge during regular business hours if that is what is required), to over $1,000 it if requires a high voltage isolation.

For a Service Call – After Regular Hours, this can range from $175 (minimum call out charge) up to over $1,000 depending on the complexity and number of staff needed.

c) *When a customer requests an "Income Tax Letter" it has historically been a request for a copy of their last 12 months bills which they will then claim on their income tax return. FHI always directs the customer to its web portal to gain this themselves, however those customers who choose not to access this on their own or do not have the means to access through the portal, are provided with printed copies of their bills, and charged $15.*

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9-STAFF-43
Interrogatory:

Lost Revenue Adjustment Mechanism (LRAM)
Ref 1: Exhibit 9, p. 29
Ref 2: Exhibit 1, p.23-24, Section 2.1.3.9

Preamble:
Festival Hydro notes it does not intend to file a claim for the true-up of the one additional project post the OEB's approval of its 2023 IRM application under EB-2022-0032 as the impact of the project would likely be less than $2K (in favor of Festival Hydro) and the third-party assistance cost for LRAM would exceed this value.

Question(s):
a) Please confirm that Festival Hydro is foregoing the true-up associated with this project and does not plan to claim the true-up in future years.

Response:
a) FHI confirms that it will be foregoing the true-up for this specific project. FHI expects that it will participate in new CDM programs as they are developed and will likely seek disposal for any new projects/programs at that time.

9-STAFF-44
Interrogatory:

Ref 1: FHI_2025_DVA_Continuity_Schedule_CoS_1.0_20240426.xlsb, Tab 6, Class A Consumption Data

Rate Classes with Class A Customers - Billing Determinants by Rate Class		Transition Customers (Total Class A and B Consumption)	Class A Customer for Full Year (Total Class A Consumption)	
Rate Class		**Test Year Forecast**	**Test Year Forecast**	**2023**
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh	-	234,539,717	240,593,044
	kW	-	561,134	521,741
LARGE USE SERVICE CLASSIFICATION	kWh	-	29,085,391	29,085,391
	kW	-	44,439	43,436

Question(s):

a) OEB staff notes that Festival Hydro has two transition customers for 2023. However, the Class A consumption in the table above which is copied from Tab 6 of the DVA continuity schedule is blank. Please fill in the consumption data for the class A customers in both kWh and kW and provide an updated DVA Continuity Schedule.

Response:

a) FHI does not anticipate any transition customers in 2025, which causes the entries to remain blank.

9-STAFF-45
Interrogatory:

Ref 1: FHI_2025_DVA_Continuity_Schedule_CoS_1.0_20240426.xlsb, Tab 3, Appendix A

Preamble:
Festival Hydro provided explanations for variances between its 2023 RRR reporting and 2023 disposition amount in the DVA Continuity Schedule for:

- Account 1522 Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges of a difference of $106k, and
- Account 1592 PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes of a difference of $301k

In both cases, Festival Hydro explained that “adjustments were made to correct this account as part of this Application and have not been adjusted on the 2023 financial statements. It will be adjusted in 2024 as part of the approval of the disposition.”

Question(s):

a) Please describe the nature of the adjustments.

b) Has Festival Hydro resubmitted its RRR reporting for 2023 to correct those balances? If not, please contact the OEB’s performance analytic group for data revision.

Response:

a) These were corrections made during the final stages of the Application submission based on FHI’s understanding of these two variance accounts. At the time of the adjustments the yearend audit was complete.

b) FHI will resubmit based on the results of the IR responses.

9-STAFF-46
Interrogatory:

Ref 1: FHI_2025_Filing_Requirements_Chapter2_Appendices_1.0_ 20240508.xlsm, tab 2BA
Ref 2: FHI _AIIP_Comparison_20240508.xlsx

	Capital Additions		
Year	**Additions per Appendix 2BA (column E)**	**Additions per the AIIP excel file**	**Difference**
2018	3,232,721	4,659,921	(1,427,200)
2019	3,167,521	4,582,799	(1,415,278)
2020	2,758,650	4,186,506	(1,427,856)
2021	3,376,986	5,007,264	(1,630,278)
2022	3,973,884	3,609,786	364,098
2023	4,890,430	4,774,362	116,067

Question(s):

a) OEB staff notes that the capital additions at reference 1 and reference 2 are materially different. OEB staff expects that actual capital additions are the same in both schedules. Please explain why there is a difference.
    a. Please update the schedules as needed.

Response:

a) *FHI has included an AIIP calculation completed by its external corporate tax preparer in Attachment 5. Please note that the majority of the impact relates to smart meter and transformer inventory being capitalized for tax purposes but not accounting purposes so 2-BA and tax will not agree. The attached spreadsheet agrees to the variance requested in Exhibit 9.*

    a. *FHI is not requesting changes to it's DVA request in Exhibit 9.*

9-STAFF-47
Interrogatory:

Ref 1: EB-003-2023, Accounting Order, November 2, 2023[3]
Ref 2: Cloud Computing Implementation Q&A Document, PDF, February 2024[4]

Preamble:
On November 2, 2023, the OEB issued the Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs (Cloud Computing Implementation Report). The

[3] EB-2023-003, Accounting Order.
[4] Cloud Computing Implementation Q&A Document, February 2024.

Cloud Computing Implementation Report noted that the Cloud Computing Implementation Account is generally intended to record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing. In February 2024, the OEB hosted a webinar and Q&A session related to the Accounting Order for the establishment of a deferral account to record cloud computing arrangement implementation costs and issued a Q&A document.

OEB staff notes that Festival Hydro did not include this generic account in Exhibit 9.

Question(s):

a) Please confirm whether Festival Hydro has considered cloud computing solutions in its rebasing term and whether any amounts have been included in its forecast.
    1) If not confirmed, please explain why. Please confirm Festival Hydro's proposal to address its cloud solution implementation needs during its rebasing term.

b) Please confirm that Festival Hydro does not request the disposition of any balance in the generic cloud implementation costs DVA in this application and does not intend to record any costs in 2024 in this generic account. If confirmed, please confirm that Festival Hydro is to discontinue the account in this rate application and update the evidence accordingly.

Response:

a) FHI considered the use of this account but has not included it in this Application as FHI believes that it meets IFRS capitalization rules for the implementation of its CIS and ERP solutions. FHI has not forecasted amounts going to the generic deferral account.

    1) Where possible, FHI has ensured that system implementations meet the IFRS capitalization rules in order to avoid the impact of high operating expenses in implementation years. FHI may choose to use the generic deferral account in future years if a future cloud computing solution cannot meet the IFRS implementation rules.

b) *FHI does not request the disposition of this account and does not intend to record any costs in 2024 in this generic account. FHI is not looking to discontinue this account as it is in very early stages of use and FHI would like to consider the possibility of using this account in future periods as noted in a).*

9-STAFF-48
Interrogatory:

Ref 1: Exhibit 9, page 18-19
Ref 2: Report of the Board – Regulatory Treatment of Pension and Other Post-Employment Benefits Costs, Sep 14, 2017

Preamble:
On September 14, 2017, the OEB released its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040)[5]. The Report clarifies the regulatory treatment of the cost of pension and OPEBs incurred by rate-regulated Ontario energy utilities as part of the overall compensation paid to their employees. A variance account was established on a generic basis effective January 1, 2018, to track the difference between the forecast accrual amounts recovered in rates and the actual cash payments made for both pension and OPEBs. The account has an asymmetric carrying charge sub-account in favour of customers.

Page 21 of the Report states that effective January 1st, 2018, utilities will establish three sub-accounts:

- Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential
- Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account
- Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges

When the cumulative accrual amount exceeds the cumulative cash payments, the primary account will hold a credit balance. When the cumulative cash payments exceed the cumulative accrual amount, the primary account will hold a debit balance. The primary account will accrue carrying charges to be returned to ratepayers when the cumulative opening monthly balance of the account is in a credit position. The contra account will not accrue carrying charges. The primary sub-account and contra sub-account are offsetting. Disposition can only result in a credit refund of carrying charges to ratepayers [emphasis added by OEB staff].

Carrying charges shall apply to the primary sub-account only (not the contra sub-account), calculated using simple interest applied to the monthly opening balances in Pension and Other Post-employment Benefits (OPEBs) Costs the primary sub-account. The interest rate shall be the CWIP rate prescribed by the OEB.

In table 9-11 of Exhibit 9 of reference 1, Festival Hydro calculates the variance between the approved other post employee benefits (OPEBs) from 2015 (increased by the annual IRM rate) compared against the cash difference.

Festival Hydro is requesting to dispose of $97,920 for Account 1522 Pension & OPEB Forecast Accrual vs Actual Cash Payment.

Question(s):

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[5] Report of the Board - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (final report) (oeb.ca).

a) Please explain why Festival Hydro requests a debit of $97,920 in this application, given that the OEB's report on Pension and OPEB states that "Disposition can only result in a credit refund of carrying charges to ratepayers".

b) Please show the accounting entries for 2023 for the three sub-accounts reconciled to table 9-11 of the application.

c) Please confirm whether the cumulative balance of the primary sub-account and contra-account results in a debit or a credit balance for each of the years between 2018 and 2024 (inclusive).
    1) If the annual amount results in a credit balance, please calculate the carrying charges using the OEB's prescribed interest rates for CWIP.
    2) Please update the applicable evidence, as needed.

<u>Response:</u>

a) FHI has decided to withdraw its request for the OPEB claim. This account should be discontinued.

b) See part a).

c) See part a).

    1) See part a).

    2) DVA continuity has been updated to reflect response in part a).

9-STAFF-49
<u>Interrogatory:</u>

Ref 1: The OEB's Decision and Order for Getting Ontario Connected Act Variance Account, October 31, 2023

Preamble:
On October 31, 2023, the OEB issued a decision and order EB-2023-0143 for Getting Ontario Connected Act Variance Account (GOCA variance account). The decision states that:

> The OEB notes that the GOCA variance account will only be available to a utility until the end of its current IRM period. The account is not available for utilities that have reflected Bill 93 in their most recent rebasing applications.
> The disposition of any balance in this account will be subject to a prudence review and a requirement to establish that any cost incurred over and above what is provided for in initial and IRM adjusted base rates is an incremental cost resulting from Bill 93.

OEB staff notes that Festival Hydro does request the disposition of any amount in the GOCA variance account nor does Festival Hydro address whether the account is to be continued or discontinued in Exhibit 9.

Question(s):

a) Please confirm that the OM&A cost in the test year reflects the Bill 93 impact for the utility's locate costs.

b) If so, please confirm that the Account 1508 sub-account GOCA variance account is to be discontinued after this rebasing application and update the evidence accordingly.

c) If not, please provide the rationale why the Bill 93 impact is not reflected in the test year's OM&A cost.

Response:

a) Confirmed. FHI completes locates in-house so there are limited impacts to the utility based on Bill 93. In addition, FHI doesn't have any identified 'Building Broadband Faster Act' projects in its service territory that are expected to impact FHI.

b) Confirmed. DVA continuity updated to list 1508 sub-account GOCA with zero inputs.

c) *N/A.*

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO) INTERROGATORIES

EXHIBIT 1 – ADMINISTRATION

1-AMPCO-1
Interrogatory:

Ref: Ex 1 p.17

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.

Please further explain why FHI's forecast budgets in 2015 did not accurately reflect the 2015 business needs.

Response:
All current senior staff were not with FHI during the last Cost of Service Application so this cannot be explained. However, it appears that FHI under-requested in their 2015 Application in several areas.

1-AMPCO-2
Interrogatory:

Ref: Ex 1 p.31

FHI owns two MS in the community of Seaforth and one TS in the City of Stratford.

Please provide the age of each MS.

Response:
The Welsh St. MS has been owned by FHI, or it's predecessor since 1962.

The Chalk St. MS has been owned by FHI, or it's predecessor since 1944.

Much of the structures and equipment on each site have been updated and replaced over time.

1-AMPCO-3
Interrogatory:

Ref: Ex 1 p.32

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.

a) Please discuss how FHI communicated the change with impacted customers and provide copies of any correspondence.

b) Please provide an update with respect to customer feedback.

c) Please discuss the feedback sought from customers.

Response:

a) For one customer, FHI sent an email to first find the proper contact at the site. Once the proper contact was identified the below email was sent:

Good afternoon,

As previously mentioned, please find attached a draft bill.

This month, Festival Hydro is applying for updated rates from their regulator (the Ontario Energy Board) that will have impacts on all our customers bills.

In your case specifically, because of the size of the generator at your facility there is a unique charge called gross load billing. This is a charge that Festival Hydro receives from Hydro One each year and is intended to recover the costs Hydro One incurs to build and maintain the assets needed in order to meet the systems maximum demand.

I have attached a link to Hydro One's website that has more details.

When we input this, as well as the other impacts that have gone into these updated rates, we found that the total bill impact was on average increase of 0.7%.

To calculate this, we took a typical bill profile form last year, and used the average incremental kW at your facility over the past 12 months, that would be used to calculate GLB.

While this would fluctuate monthly, as the demand at your facility and the usage of your generator is not constant, and is only using historicals as a reference, this formed the basis for our estimate (this same bill using current 2024 rates would have been $XX).

Please let me know if you would like to have a call to discuss any questions about this or if you have any comments/concerns.

For the other customer, FHI made it known, starting at the Connection Impact Assessment, that Gross Load Billing charges would be applicable to this site, and should be factored in.

b) FHI has not received any customer feedback from their correspondence, or the draft bill impact to the first customer. As part of the design process for the other customer this was discussed as to what thresholds made it applicable for Gross Load Billing, however, there have been no subsequent discussion.

c) As outlined in the email, FHI sought feedback on any questions or comments or concerns regarding this new charge, however, nothing has been received. For the other customer, in subsequent meetings FHI discussed the purpose of the charges and requirements with the customer, but no additional concerns or questions were brought to FHI's attention.

EXHIBIT 2 – RATE BASE AND CAPITAL

2-AMPCO-4
Interrogatory:

Please provide the number of failures per year for each of the following asset classes for the years 2015 to 2023:

a) Wood poles

b) UG XLPE cable

c) Air Insulated Switchgear

d) Transformer Station equipment (identify assets with a history of failure)

Response:

a. Wood Poles

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***
Wood Poles	*0*	*1*	*1*	*1*	*0*	*2*	*2*	*4*	*0*

b. UG XLPE cable

Please see 2-STAFF-14 (b) for the requested information.

c. Air Insulated Switchgear

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***
Air Insulated Switchgear	*5*	*3*	*5*	*5*	*0*	*1*	*3*	*3*	*2*

d. Transformer Station equipment (identify assets with a history of failure)

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***
TS Equipment	*N/A*	*N/A*	*N/A*	*-T1 Temperature Gage -T1 Bucholz Relay -Battery Bank ‘B’ issue*	*-T1 Hydran Sensor Fail*	*-T2 Bucholz Relay -T1 Transformer Monitor/RTI Fail - AC Inverter failure*	*-T1J Relay Fail -Battery Bank A Cell Failure*	*N/A*	*-T1 Hydran HeaterFail -T1 Metering Unit Failure -T1 Bushing Potential Device Cable Failure*

2-AMPCO-5

Interrogatory:

Ref: Ex 2 p.59

With respect to Table 2-43, the two changes from the last COS 2-BB are highlighted in blue.

AMPCO is unclear what the changes are and can only see one blue highlight. Please explain further.

Response:
There was an error in the explanation and there is only one variance from the last Cost of Service which was identified in blue.

2-AMPCO-6
Interrogatory:

Ref: Ex 2 p.84

FHI provides burden rates in the Test Year compared to 2015.

Please explain the increase in engineering from 36% in 2015 to 60% in 2025.

Response:
There are two reasons for this 1) the percentage of time that engineering staff work on capital projects has increased from 33% in 2015 to 47% in 2024. 2) There was a new employee added for procurement in 2020 which increased this burden rate. The rate has been 60% since 2020.

2-AMPCO-7
Interrogatory:

Ref: Ex 2 Attachment 2-2 p.4

With respect to Collaboration with Other Local Community Stakeholders FHI indicates it meets with large industrial customers to understand their business strategies/growth targets.

Please discuss the frequency of these meetings and how input from the largest customers impacts the DSP and this application.

Response:
FHI strives to meet with their large industrial customers yearly and were able to meet with seven of them in 2023. In these meetings feedback was requested on the quality of service, understand what is important to them as a customer, and understand any

growth strategies, sustainability initiatives, or upcoming projects they may have that could impact FHI.

In these meetings, FHI's customers were consistent in their messaging that reliability is more important than cost. In addition, all these customers indicated that any additional demand from FHI in the short term will be on the small scale, and therefore unlikely to introduce additional demands when factoring in future load growth.

Consistent with other customer feedback from engagement surveys, FHI used this feedback to solidify the stance that the increased investment, intended to continue providing reliable power to FHI customers, is aligned with their needs and priorities.

2-AMPCO-8
Interrogatory:

Ref: Ex 2 Attachment 2-2 p.4

With respect to the Transformer Station Renewal Program, the evidence states "This program will address replacements of critical equipment due to unexpected failures, recommendations from a recently completed TS assessment report recommendations…"

Please provide a copy of the TS assessment report.

Response:
TS Assessment Report has been included as Attachment 6.

2-AMPCO-9
Interrogatory:

Ref: Ex 2 Attachment 2-2 p.30-32

With respect to Tables 5.2-11, 5.2-12 and 5.2-13, please provide a further breakdown of Defective Equipment based on equipment type.

Response:
FHI has historically categorized events by standard OEB outage categories, including Defective Equipment, and as such does not have available the requested further breakdown.

2-AMPCO-10
Interrogatory:

Ref: Ex 2 Attachment 2-2 p.81

All physical assets depreciate over time. It is necessary to continually invest in assets to maintain value and integrity. FHI aims to time capital investments in such a way that replacement of depreciated assets occurs before they become unsafe, unreliable, and uneconomical. This area aims to ensure the project, service or product replaces substandard equipment to address concerns with assets based on historical experience and performance.

Please confirm the key drivers for asset replacement.

Response:
Key Drivers for asset replacement are:

- *Failure Risk: this driver aims to minimize the failure risk associated with assets that have been deemed to be statistically the most likely to fail according to testing, inspections, and/or ACA results.*
- *Safety: this driver aims to proactively replace assets that could cause a safety hazard should the asset fail, or of assets that have shown a history of failures, to mitigate hazardous conditions for employees and the public.*
- *Reliability: this driver aims to prevent outages before assets experience failures, maintaining the reliability of the distribution system.*
- *Functional Obsolescence: this driver aims to replace equipment that due to technological changes, or lack of materials, is now obsolete.*

2-AMPCO-11
Interrogatory:

Ref: Ex 2 Attachment 2-2 p.83-84

With respect to Buildings and Equipment, FHI indicates project identification is based on asset failures as well as a third-party building condition assessment that was completed. Subsequent inspections and reports are also completed to ensure building assets are replaced at the appropriate time. This program includes the replacement of the administrative building roof in 2025 and a portion of the service center building roof in 2026, which was identified as a need in the latest building condition assessment completed in 2019 and further reinforced by subsequent inspections of the roof in 2023.

Please provide a copy of the 2019 building condition assessment.

Response:
The 2019 building condition assessment can be found in Appendix B of FHI's DSP. Exhibit 2 Attachment 2-2.

2-AMPCO-12
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project AMI 2.0

FHI provided a forecast of the number of new/upgraded services for the years 2025 to 2029 based on historical levels and using information from developers where available.

Please provide the data for the years 2015 to 2024.

Response:
Please see below table for requested data. Please note that 2024 is still a forecasted number.

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***
# of new lots connected	*81*	*128*	*129*	*129*	*67*	*81*	*156*	*125*	*46*	*99*
# of service layouts completed	*109*	*97*	*107*	*114*	*133*	*184*	*200*	*204*	*201*	*190*

2-AMPCO-13
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project AMI 2.0

The AMI 2.0 RFP was released in 2023. In Q1 of 2024, FHI received Board approval to enter a contract with the preferred AMI 2.0 vendor (for meters, network equipment, HES, software licences, and professional services).

a) Please provide the approved contract price by year, current meter deployment plan by year, and the forecast in-service date.

a) Please provide the number of residential meters that are at 15 years of age in 2025.

b) Please provide the number of Commercial/Industrial meters that are at 15 years of age in 2025

c) Figure 4 provides the percentage of meter failures identified through RMAs by year. Does this data reflect residential meters only?

Response:

a. FHI is still negotiating final contract terms and timing with the approved vendor, as such the contract price by year is not finalized. FHI's board gave approval to enter into contract negotiations understanding the duration and planned pacing of the deployment as well as the overall cost of the project.

The current meter deployment plan involves the mass replacement of approximately 4,500 meters in 2025 (providing a ramp up period to accommodate the incorporation of lessons learned from the pilot); the sustained mass deployment of approximately 5,600 meters per year from 2026 through 2028; and ramping down to completion in 2029 with the installation of approximately 1,100 meters.

Based on this plan, the expected contract price by year to purchase the required services and equipment is:

	2025	**2026**	**2027**	**2028**	**2029**
$ (000's)	$1,210	$1,500	$1,500	$1,500	$342

Currently, the forecasted completion date is 2029. However, as assets are put into service and become used and useful, they will be capitalized, which will happen on an annual basis.

a. FHI will have approximately 16,300 residential meters that are at 15 years of age in 2025, which represents 85% of FHI's residential meter population.

b. FHI will have 2,005 Commercial/Industrial meters that are 15 years of age or greater in 2025, which represents 64% of FHI's meter population.

c. This data reflects all Trilliant meters that have had to be sent back for RMAs, which includes commercial meters as well.

2-AMPCO-14
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Overhead Pole-Line Replacement

Please provide the number of poles forecasted to be replaced under this program for each of the years 2024 to 2029.

Response:
Please see below for the requested information.

	2024	***2025***	***2026***	***2027***	***2028***	***2029***
# *of Poles Replaced (forecast)*	*33*	*59*	*75*	*75*	*75*	*75*

2-AMPCO-15

Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Overhead Pole-Line Replacement

With respect to Asset History and Performance, FHI indicates that asset history shows regular failures (>1 each year) or >50% of asset class in poor or worse condition.

Please provide the supporting data.

Response:

Please see 2-AMPCO-4 for asset failure history.

Furthermore, >50% of the asset class that is being replaced in this program has been identified as being in poor or worse condition by the Asset Condition Assessment. Specifically, in 2025, 45 of the poles being removed have been identified as being in poor or very poor condition.

2-AMPCO-16

Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Overhead Pole-Line Replacement

The Preferred Option is to replace Like for Like to New Standards. All poles, and where appropriate, associated hardware and equipment, are replaced with the latest standard design.

Please discuss the latest standard design compared to 2015, provide the year of the design change, and compare costs to 2015.

Response:

Design standards have changed since 2015 in the following ways:

> *- FHI must design pole lines to a more restrictive design standard as a change was made from linear to non-linear design analysis for pole line designs. This typically leads to additional anchoring being needed, as well as in certain circumstances higher class poles. This change occurred in 2015.*
> *- There have also been updated CSA standards that FHI must design to. The main update occurred in CSA 22.3 1-20: R2022 with updated windspeeds based on climate change. This change was introduced in 2022.*

For these updated designs, FHI is unable quantify the exact impact this has had, as analysis using the old and new methods are not both completed to be able to compare the difference between the methods.

- In 2017, FHI began installing wildlife guards on all transformer bushings. This adds approximately $10-$20 for each transformer on the job.
- In 2023, FHI began installing wildlife guarding on overhead conductor in areas susceptible to wildlife contacts, including on overhead rebuilds. This adds approximately $300-$900 to the job depending on if it is single phase or three phase.

2-AMPCO-17
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Switchgear Replacement

Please provide the number of switchgear to be replaced in each of the years 2024 to 2026.

Response:
There are two switchgears planned to be replaced in each of the years 2024 to 2026.

2-AMPCO-18
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project System Re-Establishment

a) Please explain why work of this nature has not been undertaken by FHI prior to 2025.

b) In each of the remaining forecast years, one project of a similar scope will be completed, providing an additional three phase tie in an area that does not currently exist, to facilitate the replacement of end-of-life assets.

   Please explain why the projects beyond 2025 are not identified at this time.

Response:

a. Historically, FHI has not invested significantly in Underground Renewal, and the vast majority of underground projects FHI did complete were in areas that suitable loops already existed, and cable could be removed and replaced without impacting downstream customers. However, there are now areas that have been identified as needing replacement which no longer have redundant supplies, and when examining these areas for potential rebuilds, it has been discovered that rebuilding the existing infrastructure would cause multiple extensive outages to downstream customers, leading to the development of this program.

b. *FHI has identified multiple projects that will be included under this program; however, they were not included in the narrative as detail was solely given to the test year project.*

2-AMPCO-19
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Transformer Station Renewal

Please explain why the historical pace of investment is not appropriate.

Response:
FHI's transformer station was put in service in 2013. Throughout the first six or seven years, the station did not require much replacement or capital investment as the equipment was all new and within its expected service life.

However, in recent years, different components, have begun to reach the end of their life or been discontinued prompting FHI to invest in replacements and upgrades, most notably the replacement of numerous protection relays across 2020-2023.

Also, FHI has experienced premature failures of certain equipment, most concerningly, the 230kV metering units, which caused loss of supply and generation to all other customers on the same transmission circuit and eliminated the redundancy of FHI's station, which subsequently lead to a station outage when the other transmission circuit was lost. The failure of the metering unit anecdotally appears to be an issue with this specific manufacturer/model/vintage of device. Other Ontario LDCs and Generators have suffered catastrophic failures of similar vintage of metering unit of this make/model that also damaged adjacent 230kV equipment and led to both a significant partial station outage of significant duration as well as a large unplanned capital cost to repair/upgrade their equipment. FHI has also experienced failures of the devices used to monitor the station transformers. These devices are considered obsolete from both a technological and manufacturing standpoint and the replacement of these assets is critical to both the short- and long-term operation of the station in its full capacity as they provide continuous real-time measurements that ensure the power transformers do not have any developing internal issues.

FHI believes that this new pacing will allow FHI to ensure that this critical asset is able to continue operating reliably in the future.

2-AMPCO-20
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Underground Renewal

Please provide the km of cable replaced forecast for each of the years 2024 to 2029.

Response:

Please see the below table for the requested information.

	2024	2025	2026	2027	2028	2029
Underground Cable Replaced (km)	*4.3*	*4.4*	*4.5*	*5.5*	*5.5*	*5.5*

2-AMPCO-21

Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: Project Distribution Automation

a) Please add 2023 data to the Table on page 1.

b) Please provide the volume of work for each of the years 2025 to 2029.

Response:

a. *Please see below for requested information.*

Feeder	% of Customer Base (2023)	2018	2019	2020	2021	2022	2023	Total	% of Outage Minutes (2019-2023)
68M3	20.2%	143,001	922,089	285,557	969,396	14,763	19,379	2,354,185	28.41%
68M5	19.7%	749,759	485,094	208,967	353,715	42,575	456,487	2,296,597	19.87%
8051M1	15.5%	105,158	291,569	16,467	86,288	402,454	88,931	990,867	9.88%
9M4	3.8%	535,066	6,042	314,234	581	74,827	80,545	1,011,295	11.38%
9M3	6.1%	26,220	35	150	514,724	37,962	37,759	616,850	7.59%

b. *In each of the years 2025-2029 FHI plans to purchase and install one recloser, and one set of remote fault circuit indicators.*

FHI will also replace discontinued radios throughout this forecast period on existing infrastructure and expand the use of FLISR in their service territory once enough reclosers have been installed that would enable this technology to be used effectively.

2-AMPCO-22

Interrogatory:

Ref: Ex 2Attachment 2-2 Appendix A Material Investment Narrative: Project Voltage Conversion

FHI has not had a targeted 4kV voltage conversion program over the historical period.

Please provide the scope of the projects for each of the years 2026 to 2029.

Response:
In each of the years 2026 to 2029 the scope of the projects under this program involves the replacement of 25 poles, upgrading the infrastructure to accommodate 27.6kV.

Please see the map in Attachment 7 for the scope of work planned for each requested year.

2-AMPCO-23
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: General Plant Buildings

Please provide the scope of the projects for each of the years 2026 to 2029.

Response:
Please see below for material projects planned for each of the years 2026 to 2029.

2026:
- *Service Centre Roof Replacement*

2027:
- *Admin Building Parking Lot Paving*
- *Service Centre Rooftop Units/Heating*
- *Service Centre Exhaust Ventilation System*

2028:
- *Service Centre Block Wall Refurbishment*
- *Service Centre Admin Area and Lighting Upgrades*

2029:
- *Admin Building Window Replacement*
- *Admin Building Exterior Stairs, Sidewalks and Ramps*

2-AMPCO-24
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: General Plant Fleet

The forecast cost in 2024 is $450,000. Please provide the vehicles proposed for replacement in 2024 and confirm the delivery date.

Response:
The 2024 costs are to replace a single 42' bucket truck which was purchased in 2022 following a competitive tender process, this delivery date has been delayed by the manufacturer into 2025 due to a delay in chassis delivery.

2-AMPCO-25
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix A Material Investment Narrative: General Plant IT Hardware

Please provide the scope of the projects for each of the years 2026 to 2029.

Response:
Please see below for material projects planned for each of the years 2026 to 2029.

2026:
- *Laptop Lifecycle Replacement*
- *Server Lifecycle Replacement*
- *Disaster Recovery and Business Continuity Upgrades*
- *Network Security*

2027:
- *Laptop Lifecycle Replacement*
- *Server Lifecycle Replacement*
- *Firewall Upgrades*
- *Network Security*

2028:
- *Laptop Lifecycle Replacement*
- *Field Device Lifecycle Replacement*
- *Network Switch and Access Point Replacement (Phase 1)*

2029:
- *Laptop Lifecycle Replacement*
- *Network Switch and Access Point Replacement (Phase 2)*
- *Privileged Access Management Upgrades*

2-AMPCO-26
Interrogatory:

Ref: Appendix 2-AA (excel)

a) Please add a column to Appendix 2-AA to show 2024 YTD expenditures by project and provide a copy of Appendix 2-AA in excel.

b) Please advise of any updates to the 2024 capital forecast/in-service additions.

Response:

a. Please see live excel 2-AMPCO-26 – Copy of Table 2AA – 2024 YTD_20240725 which contains the requested information in Appendix 2-AA.

b. Please see Please see live excel 2-AMPCO-26 – Copy of Table 2AA – 2024 YTD_20240725 that also includes a column with updates to 2024 capital forecast/in-service additions.

2-AMPCO-27
Interrogatory:

Ref: Ex 2 Attachment 2-2 Appendix J

a) Page vii: Kinectrics Inc. recommends FHI conduct an ACA on a regular basis. How often does FHI plan to conduct an ACA?

b) Page vii: Kinectrics Inc. recommends FHI start tracking OH Conductors and UG failures by location in the outage database and once sufficient data are available they could be incorporated in the ACA. Please discuss the current status and FHI's plan to implement this recommendation.

c) Page 1: Please identify other major asset categories not included in the 2023 Asset Condition Assessment (ACA).

d) Page 16 Table 2: For each Asset Category in Table 2, please provide the quantities replaced for the period 2019-2023.

e) Page 16 Table 2: For each Asset Category in Table 2, please provide the forecast quantities replaced for the each of the years 2024 to 2029.

Response:

a) FHI plans to continue conducting a fully updated ACA on its current basis, which is every 4-5 years.

b) FHI's Outage Management System has been configured to track outages for defective equipment down to a component level. Meaning that FHI will now be able to track these types of outages on a go forward basis for both OH and UG conductors. This change is being incorporated into FHI's 2024 outage database.

c) FHI believes it included all pertinent major asset categories in the 2023 ACA for which investment plans were derived and used consistent asset categories from the last ACA.

d) *Please see below for requested information.*

	2019	2020	2021	2022	2023
Power Transformers	0	0	0	0	0
MS Switchgear	0	0	0	0	0
Padmounted Transformers	18	14	12	17	22
Pole Mounted Transformers	13	10	12	16	12
Wood Poles	47	33	56	61	64
Concrete Poles	16	12	11	5	16
OH Primary Conductor	1310	1100	1525	2445	2880
UG Primary Cable - XLPE	2.3	2.9	2.5	5.5	1.3
UG Primary Cable - TRXLPE	0	0	0	0	0
OH Gang Switches	1	1	1	1	1
Pad Mounted Switchgear - Solid Dielectric	0	0	0	0	0
Pad Mounted Switchgear - Air Insulated	5	3	1	1	0
Structures - Vault	0	0	0	0	0
Structres - Manhole	0	0	0	0	0
Fleet Vehicles - Pickup	1	0	0	1	1
Fleet Vehicles - Bucket	0	0	0	0	0
Meters - Residential	1485	1427	1393	901	761
Meters- Industrial/Commercial	589	277	147	164	63
Meters - Primary metering Unit	0	0	0	1	1

e) *Please see below for requested information.*

	2024	2025	2026	2027	2028	2029
Power Transformers	0	0	0	0	0	0
MS Switchgear	0	0	0	0	0	0
Padmounted Transformers	25	25	25	30	30	30
Pole Mounted Transformers	11	19	19	19	19	19
Wood Poles	53	75	75	75	75	75
Concrete Poles	9	25	25	25	25	25
OH Primary Conductor	3700	2980	2980	2980	2980	2980
UG Primary Cable - XLPE	4.3	4.4	4.5	5.5	5.5	5.5
UG Primary Cable - TRXLPE	0	0	0	0	0	0
OH Gang Switches	1	1	1	1	1	1
Pad Mounted Switchgear - Solid Dielectric	0	0	0	0	0	0
Pad Mounted Switchgear - Air Insulated	2	2	2	0	0	0
Structures - Vault	0	0	0	0	0	0
Structres - Manhole	0	0	0	0	0	0
Fleet Vehicles - Pickup	0	2	0	3	0	0
Fleet Vehicles - Bucket	1	0	1	0	1	1
Meters - Residential	1031	3870	4838	4838	4838	968
Meters- Industrial/Commercial	30	635	770	770	770	155
Meters - Primary metering Unit	1	1	1	1	1	1

EXHIBIT 4 – OPERATING EXPENSES

4-AMPCO-28
Interrogatory:

Ref: Ex. 4 p.9

As shown in Table 4-2, contract labour and services costs increased by $665,893 since 2015.

Please provide a breakdown of the $665,893.

Response:
See breakdown below:

SCADA	68,185
TX Oil Sampling and Maintenance	89,100
Metering	123,189
Meter Reading	34,031
Vehicle Maintenance	107,673
Tree Trimming	34,338
Operations Maintenance	35,021
IT Services	124,356
Regulatory	50,000
	665,893

4-AMPCO-29
Interrogatory:

Ref: Ex 4 p.10

FHI's Collective Agreement expires on April 30, 2025, and FHI is planning to have a new
contract in place in the test year. FHI used an inflationary cost of living rate increase for all labour related costs.

a) Please provide the annual wage increases by employee group for each of the years 2015 to 2024.

b) Please provide the value of the inflationary cost of living rate increase used by year for all labour related costs.

Response:

a) *See table below.*

		2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Management		4.54%	4.15%	4.75%	7.67%	5.50%	5.86%	8.70%	6.71%	7.66%
Non-Management		4.20%	4.62%	2.67%	3.37%	3.62%	3.37%	3.65%	4.74%	2.73%

b) See table in 4-AMPCO-35 which includes the pay band increases by year. This is only related to wages and does not include annual increases for benefits. Those are shown in Table 4-14 in Exhibit 4.

4-AMPCO-30
Interrogatory:

Ref: Ex 4 p.12

FHI indicates Tree trimming is increasing due to increased tree trimming frequency and the cost of labour is more expensive.

a) Please provide details on the change in tree trimming frequency and the timing of the change.

b) Please provide FHI's tree trimming accomplishments for the years 2015 to 2023 and the targets for 2024 to 2029.

Response:

a. *FHI first changed tree trimmings in 2017 when all tree trimming work was contracted out. Prior to this, all communities other than Stratford were completed by FHI staff, however this was changed to have them focus on powerline maintainer work.*

   The main change has occurred in 2025, where FHI, taking feedback from Customer Surveys, which indicated that a majority of customers were willing to pay less than $1 per month to increase investment in this area. Accordingly, FHI has increased the 2025 budget by $20,000. This would allow FHI to trim one extra community (or half community in St. Marys case) on average.

b. *Please see below for requested information of areas trimmed in each of the historical and forecast years.*

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Brussels				X				X			X			X	
Dashwood			X				X			X		X			X
Hensall			X				X		X		X			X	
Seaforth	X	X		X				X			X		X		X
Stratford	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
St Marys	X	X			X	X			X (partial)	X (partial)		X (partial)	X (partial)		X (partial)
Zurich			X				X		X			X		X	

4-AMPCO-31

Interrogatory:

Ref: Ex 4 p.23

Please recast Table 9 on the basis of external labour only.

Response:

FHI was unsure what was meant by this question, however FHI removed all internal labour related costs from 2-JC to leave with external costs only. Due to allocations and other labour-related adjustments (ex. forecast periods benefits costs), the groupings may be slightly different, but this is what could be completed in a short time frame.

	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Admin											
Administration, Third Party, Software and Communications	718,666	804,710	828,929	814,969	614,946	548,454	634,611	666,680	747,654	718,274	861,064
Insurance, Benefits and Employee Future Benefits	931,841	905,695	869,915	1,002,906	988,528	979,963	938,523	996,639	1,139,384	238,200	285,840
Property taxes	96,756	38,017	55,726	82,847	74,054	135,993	126,934	126,868	151,482	143,937	154,677
Customer Focus											
Bad Debt	75,000	73,502	99,501	49,527	104,032	39,720	120,944	53,870	126,670	71,795	71,795
Customer Service, Billing, Collecting & Software	1,117,902	1,223,668	1,174,210	1,140,176	1,155,673	721,918	774,004	873,139	936,258	1,005,055	1,021,211
Community Relations & Safety	10,879	10,494	12,542	10,329	10,438	10,718	10,750	10,863	10,907	10,370	21,550
LEAP	13,000	13,200	13,410	13,510	13,650	13,860	30,060	14,550	15,000	15,630	20,050
Operations & Mtce											
Engineering and Metering	144,123	196,421	310,297	320,405	198,691	195,591	167,734	285,847	313,292	304,029	316,018
Vegetation Management	74,895	68,811	146,848	75,099	95,299	138,969	116,953	126,285	132,320	133,010	167,661
Building Maintenance	120,055	156,157	152,746	99,448	102,509	86,106	89,116	109,058	104,881	116,718	119,585
Customer Related O&M	620,002	610,116	694,705	713,954	666,606	480,278	554,779	665,993	660,966	735,296	774,165
Stations O&M	191,805	138,543	135,610	181,226	158,220	145,490	222,146	225,231	276,091	221,438	340,133
System O&M	113,590	105,997	127,306	200,090	63,141	161,705	141,502	207,933	134,247	170,530	196,235
Public & Regulatory Responsiveness											
Regulatory	138,889	165,982	111,891	135,864	170,726	120,847	89,514	171,702	176,966	206,308	400,624
	4,367,403	**4,511,313**	**4,733,637**	**4,840,350**	**4,416,512**	**3,779,611**	**4,017,569**	**4,534,657**	**4,926,115**	**4,090,591**	**4,750,608**

4-AMPCO-32

Interrogatory:

Ref: Ex 4 p.29

An Executive Compensation review was completed in 2023 for 2024. These results were built into 2025 estimates.

Please provide a copy of this review.

Response:

Please see responses in 4-Staff-20.

4-AMPCO-33

Interrogatory:

Ref: Ex 4 p.31

FHI attempts to be aligned with the P50 for all non-union and management positions.

a) Please provide the compensation cost variance from P50 for non-management positions.

b) Please provide the compensation cost variance from P50 for management positions.

Response:

a) See summary below, 2023 wages are below the P50. In many cases this is due to FHI employees not being at top rate in their grid yet. The P50 is based on top rate.

	2023 Mearie P50/Regional LDC P50	2023 Wages (Assuming annual pay)	Variance
Management	1,778,700	1,650,566	128,134
Non-Management	1,360,267	1,219,395	140,872
			269,006

b) See part (a) above.

4-AMPCO-34
Interrogatory:

Ref: Ex. 4 p.33

Table 4-12 provides total salary and wages including overtime and incentive pay split between management and non-management.

Please provide a breakdown of salary, overtime and incentive pay separately for management and non-management.

Response:

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual
Total Salary and Wages including overtime and incentive Pay						
Management (including executive)	1,065,631	1,128,790	1,116,746	1,166,624	1,287,655	1,298,176
Incentive	-	-	-	-	-	-
Non-Management (union and non-union)	2,132,566	2,042,545	2,002,432	2,170,346	2,218,804	2,170,136
Overtime	137,717	131,230	165,160	217,440	172,964	163,515
Total	**3,335,914**	**3,302,566**	**3,284,338**	**3,554,410**	**3,679,423**	**3,631,827**

	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Total Salary and Wages including overtime and incentive Pay					
Management (including executive)	1,314,153	1,428,590	1,485,702	1,801,170	1,905,441
Incentive	-	-	122,375	142,960	147,965
Non-Management (union and non-union)	2,064,245	2,100,105	2,232,402	2,587,338	2,669,213
Overtime	181,462	160,017	152,032	154,379	178,919
Total	**3,559,861**	**3,688,712**	**3,992,511**	**4,685,846**	**4,901,538**

Please note, overtime is paid to non-management only. Also, incentives were paid to the CEO in 2022 but this was not separated out as it would indicate private information for one individual.

4-AMPCO-35
Interrogatory:

Ref: EX. 4 p. 34

Total salary and wage costs increased by 35% since 2015 Board Approved or 3.2% per year. While this is slightly higher than inflation, this accounts for both annual step increases and cost of living increases for employees.

Please explain and quantify the cost-of-living increases for employees by year.

Response:
See table below, in years 2017-2023, cost-of-living and pay equity were built into the annual increase specifically for the lower end of the range where some roles were outpacing regional comparators, so their cost-of-living percentages were decreased to avoid red circling a group of employees in a future year.

Cost of Living Increase

2015	1.75%	
2016	1.75%	
2017	1.5-2.2%	*
2018	1.5-2.33%	*
2019	1.5-2.33%	*
2020	1.5-2.33%	*
2021	1.5-2.0%	*
2022	1.5-2.0%	*
2023	2.0-2.6%	*
2024	3.50%	
2025	3.50%	

*COL increases varied depending on position
as pay equity was previously also built into
annual increases until a full review was complete

4-AMPCO-36
Interrogatory:

Ref: EX. 4 p. 35

Benefit costs have increased over the same time period by 93% or 8.5% per year. The cost of benefits that was approved in the 2015 Application was $862K but the actual cost of benefits in that year was 1.15M, a difference of $291K or 34%.

Please explain the variance in 2015.

Response:

The written statement in evidence had an error for 2015 the benefit cost in 2015 was $948K as shown in Table 4-14, an increase over approved of 10%.

4-AMPCO-37

Interrogatory:

Ref: EX. 4 p.35

Table 4-13 provide the Benefit Expense Rates for 2024 and 2025.

Please provide the Benefit expense Rates for 2015.

Response:

	2015	2024	2025
CPP Max	53600	68500	68500
OMERs Tier 1 up to CPP max	9.00%	9.00%	9.00%
OMERs Tier 2 over CPP max	14.60%	14.60%	14.60%
EHT	1.95%	1.95%	1.95%
WSIB Max	85200	112500	112500
WSIB	1.07%	0.87%	0.87%
CPP Employer	4.95%	5.95%	5.95%
EI Employer	1.30%	1.26%	1.26%

4-AMPCO-38

Interrogatory:

Ref: EX. 4 p.56

For the 2025 Test year, FHI estimates one-time costs associated with the COS Application.

Please identify other one-time costs over the period 2015 to 2014.

Response:

There are no other one-time costs over the period outside of costs related to this Application. In 2023, FHI began to incur costs for the 2025 COS Application which are all incorporated into the total COS costs included in Table 4-22.

4-AMPCO-39
Interrogatory:

Ref: Ex 4

a) Please provide FHI's assumptions with respect to vacancies over the test period.

b) Please provide FHI's vacancy rate for the period 2015 to 2023.

c) Please provide a list by position of the current vacancies and the number of days the position is unfilled.

Response:

a) With the exception of recent Executive positions, FHI generally has low turnover. Planned turnover such as retirements are typically hired prior to the employee's departure date. For unplanned turnover, positions are re-posted upon notification of a departure and are generally filled within 1-2 months. New positions are budgeted for the month in which they are expected to be onboarded. In FHI's test year, FHI does not include vacancies. There is only one new proposed position included in this Application for 2025 that will be hired in 2024.

b)

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Vacancy Rate	2.1%	4.6%	1.4%	1.1%	0.7%	3.3%	5.0%	1.7%	4.0%

Vacancy rates above are shown for positions that were re-filled after employee departure as a percentage of total months filled. As noted, vacancy rates are very low with planned departures such as retirements being filled prior to the departure date.

c) FHI currently only has one vacancy, a Utility Maintenance Serviceperson. It is vacant as of the week of July 15 and is filled with a start date of August 6.

ENERGY PROBE (EP) INTERROGATORIES

EXHIBIT 1 – ADMINISTRATION

1-EP-1
Interrogatory:

Reference: Exhibit 1, Table 1-2 Revenue Requirement, Page 8

Question:

Please file a table similar to Table 1-2 that compares 2023 Historical Year, 2024 Bridge Year to 2025 Test Year. For 2024 use the 6+6 or the latest available estimate.

Response:

Application Summary	2015 Board Approved	2023 Actual	2024 Bridge	2025 Test
Average Net Fixed Assets	52,171,404	57,578,566	60,259,425	64,668,717
Working Capital Allowance	9,607,355	9,075,026	8,825,240	5,699,781
Rate Base	**61,778,759**	**66,653,593**	**69,084,665**	**70,368,497**
Working Capital Allowance	13.00%	13.00%	13.00%	7.50%
Regulated Return on Capital	3,797,664	4,125,931	4,619,734	4,637,878
OM&A including Property Taxes	5,188,507	7,604,454	8,369,252	9,430,261
Amortization Expense	2,082,559	2,489,000	2,734,034	3,114,180
PILs	142,098	251,355	201,221	304,086
Service Revenue Requirement	**11,210,828**	**14,470,739**	**15,924,240**	**17,486,405**
Less: Revenue Offsets	755,699	1,112,296	1,090,499	1,197,894
Base Revenue Requirement	**10,455,129**	**13,358,443**	**14,833,741**	**16,288,511**

2024 and 2025 Fixed Assets are updated based on revised projections included in the IR responses. 2-JA, 2-JC and 2-JD for the first six months of 2024 are included in 4-SEC-25 however FHI is still projecting to be on budget by the end of the year, so no change has been made.

1-EP-2
Interrogatory:

Reference: Exhibit 1, Table 1-12 Bill Impacts

Question:
What are the three largest causes of the 23% increase in the Distribution Bill for the Residential Rate from 2024 to 2025? Please provide the percentage of each cause.

Response:

The biggest impact relates to the revenue requirement changes that are detailed on pages 8-9 in Exhibit 1.

EXHIBIT 2 – RATE BASE AND CAPITAL

2-EP-3
<u>Interrogatory:</u>

Reference: Exhibit 2, DSP, Page 10

Preamble: "As FHI has observed potential increase in EV's, they have looked at the dataset on EV's from Ministry of Energy and identified areas where they have been installed to see any impact on demand. FHI has also changed residential transformer sizing and number of customers connected to plan for the increased electrification demand at each household."

Questions:

a) The quote from the DSP in the preamble seems to indicate that the Ministry of Energy has a dataset that show the location of EV chargers on the FHI distribution system. Is that right?

b) Does FHI have a record of the location of customers with EV chargers?

c) The quote from the DSP in the preamble indicates that to accommodate increased load of customers with EV chargers FHI has changed residential transformer sizing. What was the old residential transformer size and cost and what is the new one required to accommodate load from customers with EV chargers?

d) Does FHI ask customers with EV chargers to pay a contribution to offset the cost of larger residential transformers that are installed for their benefit? If the answer is yes, how is the amount of this contribution calculated? If the answer is no, please explain how FHI ensures that customers who do not own EV chargers do not subsidize customers who own EV chargers?

<u>Response:</u>

a) *The Ministry of Transportation shares an Electric Vehicle Database that shows the number of EV's registered in each Forward Sortation Area. These records can be found at [https://data.ontario.ca/dataset/electric-vehicles-in-ontario-by-forward-sortation-area.](https://data.ontario.ca/dataset/electric-vehicles-in-ontario-by-forward-sortation-area)*

b) *FHI does not have a complete record of the location of customers with EV chargers.*

c) *FHI changed from a 50kVA transformer, which cost $8,300 to a 75kVA transformer size, which cost $9,000.*

d) *FHI does not ask customers with EV chargers to pay a contribution. Consistent with the OEB's August 24, 2023, Bulletin "Residential Customer Connections &*

Service Upgrades" FHI treats transformer replacements as enhancements to the Distribution System that will allow the transformer to meet both the current and future capacity needs of the customers connected to it.

2-EP-4
Interrogatory:

Reference: Exhibit 2, DSP, Page 95

Preamble: "FHI plans to automate more of its network over the forecast period, which will also enable FHI to expand the use FLISR in its service territory."

Questions:

a) Is FHI's objective to have FLISR throughout its service territory or only at locations where it is needed?

b) Please confirm that FLISR is needed to maintain reliability in areas where there are DERs that export power into the distribution system?

c) Has FHI considered asking customers with exporting DERs to pay a contribution to offset the incremental cost of accommodating them on the distribution system? If the answer is yes, how is the contribution calculated? If the answer is no, how does FHI ensure that customers who do not own exporting DERs do not subsidize customers who do?

Response:

a) It is not FHI's objective to have FLISR throughout its entire service territory.

b) FLISR will be used in areas where there are DERs that export power into the distribution system. However, FHI's main objectives are also to provide faster service restoration, minimize outage impacts, and improve operational efficiency.

c) FHI has not considered asking customers with exporting DERs to pay a contribution. As referenced in b), the implementation of FLISR has several benefits to load customers as well.

EXHIBIT 3 – CUSTOMER AND LOAD FORECAST

3-EP-5
Interrogatory:

Reference: Exhibit 3, 2.3.1 Load Forecasts, Page 3 and Table 3-41 Distribution Revenue, Page 39

Questions:

a) Do conversions from heating using natural gas to electricity using heat pumps have any impact on the load or revenue forecasts? If the answer is yes, what is the impact in 2025? If the answer is no, please explain why not?

b) Do exporting DER such as rooftop solar panels have any impact on the load or revenue forecasts? If the answer is yes, what is the impact in 2025? If the answer is no, please explain why not?

c) Does EV charging have any impact on the load or revenue forecasts? If the answer is yes, what is the impact in 2025? If the answer is no, please explain why not?

d) Do behind the meter load displacement generators have any impact on the load or revenue forecasts? If the answer is yes, what is the impact in 2025. If the answer is no, please explain why not.

Response:

a) While Heat Pumps are anticipated to increase as discussed in the DSP, FHI has not seen a substantial uptake in recent years and expects similar trends to occur through the Test Year with increases to occur more rapidly in later years. The load forecast included in the Application aligns with current historical trends.

b) Current DERs are built into the load forecast as the load is based on historical trends. FHI has one large project in early planning but is not likely to impact the load or revenue forecast in the Test Year.

c) While EV charging is anticipated to increase as discussed in the DSP, FHI has not seen a substantial uptake in recent years and expects similar trends to occur through the Test Year with increases to occur more rapidly in later years. The load forecast included in the Application aligns with current historical trends.

d) Current behind the meter load displacement generators are built into the load forecast as the load is based on historical trends. FHI is not aware of additional behind the meter load displacement generators that will be online in the Test Year.

EXHIBIT 4 – OPERATING EXPENSES

4-EP-6
Interrogatory:

Reference: Exhibit 4, Table 4-19 Shared Services (2-N), Page 50

Questions:

a) For the quantities shown in the table on Page 50 please explain how FHI derived the following 2025 forecasts of services provided to its affiliates FHSI and the City of Stratford. Please show all calculations and sources of inputs.

Management Services	$60,982
Building & Land Rental	$7,531
Joint Pole	$34,643
Street Light Maintenance	$163,123
Water / Sewage Billing	$539,552
Building Rent	$38,339

b) Are services that are shown as "Shared Services" billed to affiliates?

c) How are the services listed as "Corporate Cost Allocation" charged to affiliates?

d) What is the 2025 rate base amount of the building listed in "Corporate Cost Allocation" as "Building Rent" and is the entire building allocated to the City of Stratford? If the answer is yes, why does FHI need to own a building that is not required for its use?

Response:

a) *Management Services $60,982 – This account was originally budget based on projections in 2023 however FHI has updated as part of this IR since other accounts have been adjusted. FHI has adjusted 2025 to 2024 budget x 4.2% (FHI IRM rate) = $61,068 x 4.2% = $63,633. Amounts have been changed in 2-H and 2-N.*

   *Building & Land Rental $7,531 – 2024 building & Land rental $7,492 increased by 2.5% (Ontario rental increase amount for 2024 used for 2025) = $7,492 *1.025 = $7,531*

   Joint Pole $34,643 – FHI did not account for no longer requiring the transfer to 1508. This amount should be $37.78 (2024 rate) x 1,550 attachments = $58,559. This amount has been adjusted as part of the total wire attachment amendment as discussed in 6.0-VECC-45 in 2-H and 2-N.

   Street Light Maintenance $163,123 – Used 2024 budget and increased by 4.2% (FHI IRM rate) = $163,123.

Water / Sewage Billing $539,552 - Used January to March 2023 actuals of $44,824 and April's $45,009 then used April's monthly amount for the remaining 8 months ($44,824 x 3) + ($45,009 x 9) = $539,552. This amount should have been increased by the 2024 OEB IRM rate of 4.8% = $565,450. This amount has been adjusted in 2-H and 2-N.

*Building Rent $38,339 - 2024 monthly building rent $3,117 increased by 2.5% (Ontario rental increase amount for 2024 used for 2025.) and multiplied by 12. = (3,117 *1.025) *12 = $38,339.*

b) *Yes.*

c) *They are billed after the services are provided.*

d) *The Service Centre is not separated in rate base from the Administration Building. Both buildings have been owned by FHI and previously the public utility for 70-80 years. The majority of capital cost upgrades have been for the Administration Building.*

   FHI would incur the full cost of the building if the City of Stratford was not using a portion of it as this building is required for FHI's distribution operations.

4-EP-7
<u>Interrogatory:</u>

Reference: Exhibit 4, Page 51

Preamble: "Building rent is based on square footage of the allocated space and therefore is fully
recovered within the cost of the market rent."

Questions:

a) What is the square footage of the space allocated to the City of Stratford?

b) What is 2025 market price per square foot for equivalent space in Stratford?

c) What is the 2025 revenue requirement of the building? Is it higher or lower than the building rent charged by FHI to Stratford? Please explain your answer.

<u>Response:</u>

a) *5127 sq. feet.*

b) *FHI has not undertaken a market analysis. Any available space for rent would need to be reviewed for the cost of retrofitting to meet the City's needs.*

c) *The revenue requirement for both buildings (as noted in 4-EP-6 (d)) is $261K for depreciation with the majority being the Administration Building and $179K for operating costs of the Service Centre. FHI would incur the full cost of the building if the City of Stratford was not using a portion of it as this building is required for FHI's distribution operations.*

4-EP-8
Interrogatory:

Reference: Exhibit 4, Pages 51 and 52

Preamble: "There were no material variances between 2025 and 2015 however the largest change elated to Water and Sewer Billing to the City in the amount of $65K due to cost per meter increasing after renegotiation, as well as, to a smaller degree, increases in customer count. Considerable effort is made by FHI to ensure affiliates are charged properly and do not
any benefits (sic) as a result of their affiliation."

Questions:

a) What were the reasons for renegotiation?

b) Please file the titles of the individual (s) representing FHI and the City in responsible for the renegotiation.

c) Considering that the City owns FHI please explain what leverage, in any, did FHI have in the renegotiation with the City.

d) Please describe the effort made by FHI to ensure that it will be properly charging the City for Water and Sewer Billing in 2025.

Response:

a) *The City of Stratford requested a review to ensure that the methodology was reasonable compared to the Town of St. Marys. FHI determined that a third-party review would be appropriate to ensure that the allocations aligned with the ARC.*

b) *FHI – CFO*
City of Stratford - Director, Infrastructure and Development Services, Director of Corporate Services/Treasurer and Manager of Environmental Services.

c) *FHI and the City of Stratford agreed that any outcome needed to align with the results of the third-party review.*

d) *The most recent agreement was signed as of January 1, 2023, for a three-year term, with the option to extend for two one-year periods. The per customer rate is increased by the prior year's OEB IRM rate annually. After the contract period is* *complete, if another contract is requested, another costing review will be completed.*

4-EP-9
Interrogatory:

Reference: Exhibit 4, Attachment 4-1, Required OEB Appendices, Table 4-18, Page 43-48, “Appendix 2-N, Shared Services and Corporate Cost Allocation” and Exhibit 4, Table 4-19 Shared Services (2-N) page 50.

Preamble: “Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.”

Questions:

a) For shared services that are charged or allocated at cost, please file the calculation that supports the amounts shown for 2025 in Table 4-19 Shared Services (2-N) on page 50. Please include all numerical cost inputs and explain their sources.

b) For shared services that are charged or allocated at market, please file the calculation that supports the amounts shown for 2025 in Table 4-19 Shared Services (2-N) on page 50. Please include all market price inputs and explain their sources.

Response:

a)

Management Services				
Labour Costs	$	44,698		
Plus: Overhead & Admin Markup		16,370		
2024 Budget		61,068		
4.2% FHI IRM Inflation		2,565		
2025 Budget	**$**	**63,633**		

Water/Sewage				
2023 Rate per Meter			$	3.52
March 2023 Num. Meters Billed		12,734		
Total March Billed x 3 months				134,472
April 2023 Num. of Meters Billed		12,787		
Total April Billed x 9 months				405,081
Total				**539,553**
4.8% OEB Inflation				25,899
2025 Budget			**$**	**565,452**

Streetlight		
Labour Material, Transportion Costs Used for 2024 Budget	$	130,572
Plus: Overhead & Admin Markup		25,976
2024 Budget		**156,548**
4.2% FHI IRM Inflation		6,575
2025 Budget	**$**	**163,123**

b) *A market analysis has not been undertaken. Any comparator available would need to be reviewed for the cost to retrofit the space to meet their needs. 2025 market rates would also not be relevant as the contracts were signed prior to 2025.*

4-EP-10
Interrogatory:

Services Provided

Question:
Considering that the agreement is dated September 1, 2012, are the services provided by FHI to FHSI still the same as are listed in the agreement? If the answer is no, please describe the changes in services.

Response:
The services provided are the same, however billing practices have changed to ensure that FHI's personnel's time is fully recovered.

4-EP-11
Interrogatory:

Reference: Exhibit 4, Attachment 4-5, Shared Services Agreements, Page 3 of 8, Section 9 Compensation and Payment

Preamble: "For the Services described in Section 2.a(1), the Customer will pay to the Service Provider $3.07 per Account billing invoice, payable in 12 monthly installments on the first Business Day of each calendar month. Annual increases to this charge will be equivalent to the Ontario Energy Board approved "Gross Domestic Product minus Industrial Price Index less the productivity factor ("GDP — IPI less productivity index")."

Questions:

a) How was the $3.07 invoice calculated? Please file the numerical calculation and all sources of inputs.

b) What percentage of customers used paper billing in 2012 and what percentage does FHI expect will use paper billing in 2025?

c) What are the forecast costs of a paper bill and e-bill for 2025?

d) Was the $3.07 charge calculated in 2012 using the information available at that time according to the requirements OEB Affiliate Relationships Code?

e) Does the Service Provider (FHI) invoice the Customer (FHSI) before or after providing or the services?

f) What is the impact on working cash of FHI of the provision of the billing service?

Response:

a) The $3.07 in the contract is no longer used for billing. Billing is completed based on labour plus applicable overheads.

b) In 2012, 100% of FHI's customer base received paper bills each month. FHI projects 45% of customer on e-billing by the end of 2025.

c) Projected cost of paper bill for 2025 is $2.33 per customer, per month. Projected cost of paperless bill for 2025 is $1.30 per customer, per month.

d) To the best of FHI management's knowledge, yes, however there has been significant turnover since this time and the 2012 calculation is not relevant to this Application.

e) Billing is completed after providing the service.

f) *Impact on working capital may be difficult to determine without significant effort.*

EXHIBIT 6 – REVENUE REQUIREMENT AND REVENUE DEFICIENCY OF SUFFICIENCY

6-EP-12
Interrogatory:

Reference: Exhibit 6, Table 6-16 Other Revenue with Variance, Page 22

Questions:

a) Please explain the reason for the fluctuations in account 4210, Rent from Electric Property, particularly reduction from $189,160 in 2015 to $128,767 in 2021, then the increase to $166,816 in 2023 and then a decrease to $128,633 in 2025.

b) Are rental rates market based or cost based? Please explain.

c) What is account 4315 Revenues of Electric Plant leased to Others and how is it different from 4210 Revenue from Electric Property?

d) Please explain why FHI started leasing electric plant to others in 2018 and are the others affiliates of FHI.

e) Are lease rates market based or cost based? Please explain.

Response:

a) *The reduction from $189,160 in 2015 to $128,767 in 2021 was caused by FHSI no longer renting fibre room space from FHI.*

   The increase to $166,816 in 2023 is from $33K for joint pole usage relating to prior period adjustments identified and corrected in 2023.

   Joint pole has been updated in 2-H as discussed in 6.0-VECC-45.

b) *See response in 4-EP-9.*

c) *4315 includes two leases to non-affiliated businesses who use space on FHI owned land. 4315 is separated from 4210 which is used primarily for pole attachments.*

d) *One business uses a portion of a Municipal substation that has available space, and the other built a battery storage plant in 2018 on vacant land that is adjacent to the Transformer station and unutilized by FHI. Neither business is an affiliate of FHI.*

e) *These are non-affiliate transactions and were mutually agreed on by the parties and since they are non-affiliate they are market based.*

EXHIBIT 7 – COST ALLOCATION

7-EP-13
Interrogatory:

Reference: Exhibit 7, Page 12, Standby Charges

Preamble: "As noted in the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications released on December 15, 2022, "A Standby Charge is billed by a distributor to a customer with load displacement facilities behind its meter to compensate the distributor for the cost of maintaining the ability to accommodate the total load of the customer at any time. The charge must not inadvertently subsidize other customers or unduly burden the load displacement customer."

Questions:

a) How many FHI customers have load displacement facilities behind their meters?

b) Since FHI does not currently have a Standby Charge and is not proposing one, please confirm that customers who do not own load displacement facilities will continue to subsidize customers who do.

Response:

a) FHI currently has five customers with load displacement facilities behind their meters.

b) Confirmed.

SCHOOL ENERGY COALITION (SEC) INTERROGATORIES

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-1
Interrogatory:

[Ex. 1, p. 7] Festival Hydro's last rebasing application was for 2015 rates. In its deferral requests for 2020, 2021, 2022 and 2023 (2 years), it noted the following reasons for deferring:

- Good performance in terms of ROE, reliability and costs
- Adding a large new customer in 2018 for at least 3 years

Please provide an update on the large customer added in 2018, including what class they were in, total billing demand kW for each year, dates of operation and whether they are still a customer.

Response:
The large customer was added March 1, 2018. This customer was assigned the Large Use rate classification beginning March 1, 2018, and was reclassified as GS 50 to 4,999 kW for the February 2024 usage month to current. The table below details the large customer's billed demand from March 1, 2018, to December 31, 2023.

	2018	2019	2020	2021	2022	2023
January		4,532	53	8,913	183	588
February		3,997	1,037	770	94	520
March	55	3,995	6,029	5,648	64	1,188
April	347	7,847	52	121	159	459
May	2,796	7,854	52	7,055	138	150
June	8,902	7,847	107	341	487	1,780
July	6,870	85	6,048	76	437	71
August	6,882	110	756	128	647	57
September	7,059	266	410	87	648	72
October	115	2,066	165	182	796	61
November	1,074	3,332	153	173	57	30
December	1,886	5,059	8,074	111	1,144	49

1-SEC-2
Interrogatory:

[Ex. 1] Please provide all material provided to Festival Hydro's Board of Directors regarding its approval of this Application, and the underlying budgets.

Response:
Please see Attachment 8.

1-SEC-3
Interrogatory:

[Ex. 1] Please provide copies of all benchmarking studies, reports, and analyses that Festival Hydro has undertaken or participated in since the filing of its last rebasing application in 2015, that are not already included in the Application.

Response:
There are no additional relevant benchmarking studies, reports or analyses that FHI has undertaken or participated in since it's last rebasing application.

1-SEC-4
Interrogatory:

[Ex. 1, Attachment 1-11, p. 6] Festival Hydro's Business Plan states that because its last Cost of Service application was in 2015 "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."

a) Please explain why Festival Hydro did not make these required investments during the deferred rebasing period.

b) When was the Business Plan developed?

c) Please provide any minutes or notes from Festival Hydro's Board of Directors when it has discussed and/or approved the Business Plan.

Response:
a) In recent years, FHI began reinvestment of major systems during the rebasing period. The building was renovated in several stages starting in 2021 and ending in 2024. CIS work started in 2023 and is live in 2024 after it was determined that the current system would no longer be supported. ERP was started in late 2023 and will go live in 2025. This was also an outcome of the current vendor no longer supporting FHI on its CIS.

b) The Business Plan was developed prior to the 2024 and 2025 budgets, but it was updated based on results of customer engagement and final submission of this Application. Several components of the Business Plan were extracted from the 2022-2024 Strategic Plan.

c) *The Board was notified verbally about the Business Plan and the revenue requirement requested as part of the Application. The only formal Board approval* *related to the 2025 budget is included in 1-SEC-2. The Board, with management, also developed the 2022-2024 Strategic Plan which provided a starting point for the Business Plan.*

1-SEC-5
Interrogatory:

[Ex. 1] Please provide details of all productivity and efficiency measures Festival Hydro has undertaken over the last five years, and any it plans to undertake in the test year and subsequent four years. Please quantify the forecasted savings and explain how they were calculated.

Response:
FHI provides the table below in response to this interrogatory.

FHI does not track quantitative information associated with productivity initiatives at a consolidated level or as part of its ongoing reporting. However, in an effort to quantify the dollar amounts associated with existing and planned productivity initiatives for the purposes of responding to this interrogatory, FHI has estimated these amounts on a best-efforts basis. The dollar amounts provided are not necessarily cost savings resulting in lower overall expenditures; they could be avoided costs which avoid incurring expenditures in the future (e.g., voltage conversion avoids need to upgrade and replace substations). For persistent savings, amounts have been calculated assuming 2023 costing.

Efficiency/ Improvement	***Effective Date or Planned Date***	***One-time or Persistent Cost Savings or Avoided Costs***	***Calculation Assumptions***
4kV Conversion Program - Capital Plan	*Focused program beginning in 2025*	*Avoided Cost - Capital replacement of Substations*	*NPV Savings of $1.55M in 2023, Refer to Ex 2, Materiality Narrative “Voltage Conversion”*
4kV Conversion Program - Station OM&A Costs	*Savings begin in 2029, year after first station is expected to be retired, full savings after last station retired and decommissioned*	*Persistent*	*Approximately $40,000 yearly ($20,000 per station) which is an average of utilities, insurance, tax, labor and contract costs*
4kV Conversion Program - Inventory Reduction	*Full savings will be seen once 4kV is eliminated*	*Persistent*	*$36,000 inventory reduction*

Utilismart Outage Management System	*2023*	*None*	*The Outage Management System does not necessarily provide a cost savings, but it does improve the accuracy/recording of outages, and provides customers with more up to date and timely information regarding outage events*
Utilismart Engineering Software	*2023*	*Avoided Cost - Replacement of overloaded Transformers*	*While difficult to quantify, this software notifies FHI's engineering staff of distribution transformers that are overloaded, allowing FHI to proactively replace transformers with a larger size prior to failure. This transformer then comes back into stock where suitable and is re-used in the future.*
Recloser Installation	*2025 and onwards*	*Persistent*	*Savings are related to automated switching and the avoided cost of sending resources to manually operate switches. Also aims to provide more reliable power to customers, and reduce impact of outages*
Remote Fault Circuit Indicators	*2023 and onwards*	*Persistent*	*Based on historical issues where these are installed, potentially 8 truck rolls a year prevented (approximately $8,000)*
E-billing	*2017 and onwards*	*Persistent*	*See 4-EP-11 Response ($1.30/customer/month)*

Painting and Sandblasting Transformers	*2020*	*Avoided Cost*	*FHI sandblasts and paints approximately 10 padmounted transformers yearly where the shell is prematurely rusting. This costs approximately $5000, avoiding the replacement cost of approximately $90,000 in new transformers*
CIS System	*2024 and onwards*	*None*	*FHI's new CIS system will allow for automation and digitization of many processes that were manual or required redundant workflows. For example, service orders will be digitized within the new CIS system, automating data and workflows, and eliminating redundant checks and entries. It will also FHI to bring their Meter Data Management in-house, allowing FHI to more effectively troubleshoot and manage this data*
ERP System	*2025 and onwards*	*None*	*FHI's new ERP system will allow for automation and digitization of many processes that were manual or required redundant workflows. For example, job estimating, budgeting, fixed assets, and material allocation will become part of automated workflows, eliminating redundant checks and entries.*

Process Documentation	*2021*	*None*	*In 2021 and 2022 FHI reviewed and created updated process documentation across the company to ensure standardized tasks and processes were reviewed, enhanced or automated where possible, and archived for future use to ensure knowledge of workflows and tasks could be more easily transferred.*
AMI 2.0 - Remote Disconnect/Reconnect	*Beginning in 2025, full benefits realized in 2029 after full deployment*	*Persistent*	*FHI's AMI 2.0 meters will have remote disconnect/reconnect capabilities, removing the need to dispatch labour resources to manually perform this task. It is estimated this will save FHI approximately $6,000-$7,000 yearly*
AMI 2.0 - Manual Meter Reads	*Beginning in 2025, full benefits realized in 2029 after full deployment*	*Persistent*	*Due to FHI's current AMI 1.0-meter issues, FHI spends approximately $35,000 yearly manually reading meters. After AMI 2.0 is fully deployed, it is expected this cost will be significantly reduced, as the intended AMI network design includes 100% meter coverage*
Outsourcing bill prints	*2023*	*Avoided Costs*	*See 4-VECC-35 (a) for further details. However, FHI avoided approximately $50,000 investment that would have been needed to purchase new bill printer and associated equipment, along with*

			$9,000 maintenance contract.
Shared Services	*2023 and onwards*	*Persistent Savings*	*FHI has worked with other LDC's to determine any shared services cost savings. In particular, FHI partnered with another LDC to share a regulatory position, rather than hire an FTE, to ensure that FHI could stay up to date with regulatory changes and requirements, while not allocating a full FTE's costs to the position.*

1-SEC-6
Interrogatory:

[Ex. 1, Scorecard] Please file on the record Festival Hydro's preliminary scorecard for 2023.

Response:
The 2023 Preliminary Scorecard has been included in Attachment 11.

1-SEC-7
Interrogatory:

[Ex. 1, 2023 Financial Statements and Appendix 2-N]
a) Please reconcile the #s shown in 2-N for 2023 Shared Services with Festival Hydro Services Inc. with the Revenue and Expenses shown under Related party transactions in the 2023 Financial Statements, p.34.
b) Please reconcile the #s shown in 2-N for 2023 Corporate Cost Allocation to the City of Stratford with the Revenue and Expenses shown under Related party transactions in the 2023 Financial Statements, p. 33.

Response:
a) *See chart below.*

FHSI				
Revenues:	2023 Financial Statements	2-N - 2023	Difference	Notes:
Operational services	$31,538	$0	-31,538	None shared services related. Billable maintenenace work performed by FHI operations for FHSI.
Management fee	60,982	60,982	0	
Office and fibre room rentals	1,347	7,380	6,033	Financial Statements does not include rent increase in accordance to the Ontario Rent Control Guidelines and the property taxes relating to the land rental.
Joint pole rentals	57,384	34,643	-22,741	Financial Statements includes portion of revenue recognized to the 1508 DVA account.
Interest earned	3,398	0	-3,398	None shared services related. Interest on intercompany due to/from balance.
Energy sales	30,817	0	-30,817	None shared services related. Electricity billings.
Water billing and collection services	76,358	0	-76,358	None shared services related. Water billing for non affiliate service area.
Total revenues	$261,824	$103,005	($158,819)	`

b) *See chart below.*

City of Stratford				
Revenues:	2023 Financial Statements	2-N - 2023	Difference	Notes:
Energy sales	$1,342,294	$0	($1,342,294)	This is electricity billings and are not related to shared services.
Water and sewer administration fee	539,320	549,376	10,056	2-N includes $10,056 of additional City of Stratford water & sewage billable work order revenue
Street lighting services	12,617	149,367	136,750	Financial statements show street lighting revenue net of expenses.
Service centre space rental	36,851	36,851	0	
Total revenues	$1,931,082	$735,594	($1,195,488)	

1-SEC-8
Interrogatory:

[Ex. 1, p. 24, Figure 1-2, Attachment 1-15 and Appendix 2-K]

a) Festival Hydro states that FHI and FHSI (the affiliate) have the same President and CEO. How is this person's time divided between the two entities?
b) How does Festival Hydro ensure that the interests of the LDC and its ratepayers are protected with respect to purchasing services from the affiliate?
c) Figure 1-2 shows 42 positions and Attachment 1-15 shows 43, including a new billing coordinator, not including the contract positions. Please reconcile these totals with the 45 FTEs shown in Appendix 2-K.
d) Please confirm that all 45 FTEs included in Appendix 2-K are employees of the regulated company Festival Hydro, some of whom do work for the affiliate.

Response:

a) *The President and CEO's time is allotted at 4 hours per month to FHSI and the remainder to FHI.*

b) *The affiliate has extensive experience and knowledge of FHI's IT systems and workflows, and the cost of the services are reasonable for the value provided. FHSI employees track their time hourly and are allocated to specific projects or tasks for FHI. These hours are billed at the end of each month.*

c) *Appendix 2-K has been updated to 44, there is one new proposed position (Billing Coordinator) in 2025 however in half of 2023 and most of 2024, a contract FTE was brought in to assist with backfilling customer service work while the new CIS was implemented so 2-K doesn't show the increase in one position.*

   Figure 1-2, under Manager of Operations, it should say (13) instead of (12). This would bring this table to 43, plus the proposed Billing Coordinator to make 44.

   Attachment 1-15 should show (7) beside Journeyman Linesperson instead of (6) to get to 44.

d) *Confirmed, all 45 FTEs included in 2-K are employees of FHI.*

EXHIBIT 2 – RATE BASE AND CAPITAL

2-SEC-9
Interrogatory:

[Ex. 2, Table 2.12, Appendices 2-AA, 2-AB and 2-BA]

a) Please update Table 2-AA and 2-AB showing actuals to date for 2024 and an updated forecast for 2024 and 2025 if required.
b) If the forecast for either year changes, please update 2-BA.
c) Please provide actuals for 2022 and 2023 to the same date as provided in part a.
d) Please provide the source for the planned amounts for 2020 to 2024 (e.g. internal budget documents).

Response:

a. 2-AA and 2-AB are updated for 2024 and 2025 and included in Attachment 10.

b. 2-BA is updated for 2023-2024 and is included in this submission.

c. See 2022 and 2023 actuals to June 30 in Attachment 10.

d. Please see Attachment 11 for the requested information.

2-SEC-10
Interrogatory:

[Ex. 2, Distribution System Plan (DSP), Table 5.3-7]3

a) Please file on the record of this proceeding a copy of the DSP filed as part of Festival Hydro's 2015 rate application. (Note: It is sufficient for the Applicant to simply agree to deem the EB-2014-0073 DSP on the record for this proceeding and provide a link to the OEB's Regulatory Document Search, as opposed to re-filing.)
b) Did Festival Hydro prepare any DSPs between rebasing applications? If so, please provide copies.
c) If not, please provide the planning documents prepared for the capital budget forecasts for 2020 to 2024.
d) For each asset category shown in Table 5.3-7, please provide the number of assets replaced or forecast to be replaced, for each year between 2022 and 2029.

Response:

a) FHI agrees that EB-2014-0073 DSP is the one filed as part of FHI's 2015 Rate Application. It can be found at:

https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2014-0073&sortBy=recRegisteredOn-&pageLength=400

b) *No, Festival Hydro did not prepare any DSPs between applications.*

c) *Please see Attachment 11 from 1-SEC-9 (d) for the requested information.*

d) *Please see 2-AMPCO-27 (d) and (e) for requested information.*

2-SEC-11
Interrogatory:

[Ex. 2, DSP, Appendix J Asset Condition Assessment (ACA), Table 1] Please provide a revised version of Table 1 results, removing the age limiter component to the Health Index calculation. Please also provide a copy of any additional ACAs done between rebasing applications.

Response:
FHI does not have a revised version of the Table 1 results which remove the age limiter component and does not have the data available to them to do so.

Furthermore, FHI is of the opinion that age is a crucial parameter that provides essential context to an asset's condition, acting as a historical marker that reveals how an asset has deteriorated over time. Eliminating age as a condition variable could compromise the integrity of our data and the accuracy of the Health Index. In all industry health index methodologies, age is used as a key parameter, alongside others, within the Health Index calculation.

Age plays a vital role in assessing the wear and tear of an asset, enabling us to track long-term trends in performance and condition. This information is indispensable for making informed decisions regarding maintenance, repairs, and replacement strategies. Furthermore, age is a key factor in predicting an asset's future condition and performance. Without it, we risk losing the ability to proactively plan for the maintenance, refurbishment, or replacement of assets before they reach a critical state.

Please see Attachment 12 for FHI's ACA from December 2018.

2-SEC-12
Interrogatory:

[Ex. 2, p. 5 and Appendix 2-BA] Festival Hydro states 'In most cases, capital expenditures are equivalent to in-service additions except for large software system additions which spanned two years: SmartMAP in years 2022 and 2023, Customer Information System (CIS) and AMI 2.0 in years 2023 and 2024, and Enterprise Resource Planning System (ERP) in years 2024 and 2025'. No construction work in progress is shown in Appendix 2-BA for 2024 and 2025.

a) Please provide the following information and add columns if required:

Project $k	2022 Capex	2022 ISAs	2023 Capex	2023 ISAs	2024 Capex	2024 ISAs	2025 Capex	2025 ISAs
SmartMAP								
CIS								
AMI 2.0			96.5		200		1,316	
ERP					875		875	

b) Please confirm that there are no other projects for which Capex in a year is not equal to In-service Additions (ISAs).
c) Please provide a copy of 2-AB using ISAs.
d) Please provide the USoA account used for each of the above software programs.

Response:

a) *See chart below.*

Project $k	2022 Capex	2022 ISAs	2023 Capex	2023 ISAs	2024 Capex	2024 ISAs	2025 Capex	2025 ISAs
SmartMAP	223.4	-	-	223.4				
CIS			336.5	0	753.7	1,090		
AMI 2.0			96.5	0	200	296.5	1,316	1,316
ERP					551.6	0	803.2	1,354.8

b) *Confirmed.*

c) *See 2-AB using ISAs.*

First year of Forecast Period:
2025

CATEGORY	Historical Period (previous plan[1] & actual)														
	2015			2016			2017			2018			2019		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
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%
TOTAL EXPENDITURE	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%
System 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%

Historical Period (previous plan[1] & actual)															
2020			**2021**			**2022**			**2023**			**2024**			
Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual[2]**	**Forecast**	**Var**
$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*			%
721	1,086	50.8%	712	1,091	53.2%	863	1,013	17.4%	805	1,090	35.4%	1,212	861	1,484	-29.0%
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	1,236	2,493	-44.7%
55	51	-7.5%	55	6	-89.7%	55	34	-38.5%	75	110	46.9%	77	25	77	-67.3%
973	460	-52.7%	1,040	876	-15.7%	969	683	-29.5%	1,665	1,814	9.0%	4,193	1,103	3,889	-73.7%
3,683	3,225	-12.5%	3,673	4,000	8.9%	3,931	3,952	0.5%	5,014	5,128	2.3%	7,717	3,225	7,942	-58.2%
200	466	132.8%	200	481	140.7%	200	343	71.7%	400	447	11.7%	219	157	335	-28.3%
3,483	2,759	-20.8%	3,473	3,519	1.3%	3,731	3,832	2.7%	4,614	4,871	5.6%	7,517	3,068	7,607	-59.2%
$ 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	$ 1,587	$ 3,275	-52.7%

Forecast Period (planned)				
2025	**2026**	**2027**	**2028**	**2029**
$ '000				
2,399	2,463	2,531	2,601	1,743
3,101	3,351	3,421	3,505	3,590
359	374	384	397	409
2,433	1,299	1,262	1,274	1,585
8,292	7,487	7,598	7,777	7,327
327	332	338	345	352
7,964	7,156	7,260	7,432	6,974
$ 3,515	$ 3,620	$ 3,729	$ 3,841	$ 3,956

d) *See USoA accounts used below:*

Project	USoA
SmartMAP	1611
CIS	1611
AMI 2.0	1860
ERP	1611

2-SEC-13
Interrogatory:

[Ex. 2, Appendix 2-AA and DSP Material Investment Narrative Overhead Pole-Line Replacement]

a) Please provide further details on the 75% increase in OH Renewal from an average of $591k 2020-2024 to $1,031k 2025-2029.
b) Please provide the number of poles replaced each year between 2015 and 2023 and planned for 2024 to 2029.

Response:

a. *One of the main causes of the average increase in costs, is due to the significant increases in material and labour costs that have been occurring in recent years and is expected to continue into the near future. For example, FHI has seen the average pole replacement cost increase by 25% since 2021 and 37% since 2019.*

   Furthermore, through the complete ACA by Kinectrics, FHI is increasing the number of poles it will replace each year during the forecast period. On average there will be an increase of 15-20 more poles a year, which is approximately a 27% increase, being replaced when compared to over the historical period from 2015-2024, and a 60% increase, when comparing from 2020-2024.

b. *Please see below for the requested information.*

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***
# of Poles Replaced	*91*	*73*	*83*	*51*	*49*	*30*	*42*	*54*	*62*

	2024	***2025***	***2026***	***2027***	***2028***	***2029***
# of Poles Replaced (forecast)	*33*	*59*	*75*	*75*	*75*	*75*

2-SEC-14
Interrogatory:

[Ex. 2, Appendix 2-AA] The average percentage of Capital Contributions for System Access (not including AMI 2.0) for 2015 to2023 is 42%. Please explain why this percentage has dropped to 22% for 2024, 30% in 2025 and an average of 35% for 2026 to 2029.

Response:
This percentage dropped in 2022 as the proposed budget and expected capital contributions were based on known projects when this forecast was created. FHI has updated their Table 2-AA, along with forecasted capital contributions for 2024 based on work that has taken place as of June 30th or is still forecasted to occur in 2024. However, this has not significantly changed the overall percentage of capital contributions that FHI expects to receive in 2024.

This percentage is lower in 2025 again, mainly because of the work expected in the investment category "Other Capital Recoverable". In 2025, FHI is undertaking a large overhead rebuild for which their will be capital contributions, however because it is covered under the Public Service Works on Highways Act, the amount FHI can recover is limited by this Act. Historically this area receives a significant amount of capital *contribution, but that is not the case in 2025. The rest of the estimates are based on forecasted projects, where known, and historical trends.*

For 2026-2029, this number increases, and aligns closely with the percentage of System Access work funded by capital contributions in 2022 (34%) and 2023 (38%), which FHI expects to be a consistent balance going forward.

2-SEC-15
Interrogatory:

[Ex. 2, pdf p. 310, DSP, Material Investment Narrative Underground Renewal]

a) How many km of underground cable was replaced in each year between 2015 and 2023?
b) Please provide the km of underground cable to be replaced in each of 2024 to 2029.
c) Please explain the increase in cost/km of cable in 2023.

Response:

a. *Please see the below table for the requested information.*

	2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***
Underground Cable Replace (km)	*3.4*	*2.7*	*1.6*	*3.5*	*2.3*	*2.9*	*2.5*	*5.5*	*1.7*

b. *Please see 2-AMPCO-20 for the requested information.*

c. *In historical years, many of the projects FHI completed only involved the replacement of cable, requiring only minimal civil work and transformer replacements. However, in 2023 this was not the case. This was the first year that FHI required a significant amount of civil work and transformer replacements. For reference, from 2018-2022 FHI installed just under 70m of duct total, while in 2023 FHI installed 880m worth of duct, which added approximately $170,000 to the program's costs. With this cost removed to be more inline with other historical years the cost/km drops significantly. FHI has also updated the amount of cable replaced in 2023, from 1.3km to 1.7km as it was discovered to be incorrect previously due to a data error.*

   Furthermore, from 2021 to 2023 FHI saw an increase of 36% to install primary underground cable, the majority of which is driven by material cost increases.

2-SEC-16
Interrogatory:

[Ex. 2, pdf p. 339, DSP, Material Investment Narrative Buildings]

a) Based on the list provided in the Material Investment Narrative, please provide an update on the status of the planned work on the buildings for 2024.
b) Please break down the 2024 budget by each of the planned items.
c) For the list of work in 2025, please break down the budget for each item.

Response:

a. *FHI is expecting Phase 3 of the renovation to be complete the first or second week of August. This completes the updates to the IT and meeting space area on the first floor, as well as the installation of an accessible lunchroom on the first floor.*

Phase 4 of the renovation will begin immediately after completion of Phase 3. Phase 4 includes the renovation of the second floor of the administration building and is expected to finish in December 2024.

b. *Please see below for requested information:*

	Budget
Administration Building Improvement 1st Floor Renovation	$ 1,200,000
Administration building Improvement 2nd Floor Renovation	$ 940,000
Service Centre (Misc, Outdoor Rack)	$ 25,000
Total	$ 2,165,000

c. *Please see below for requested information:*

	2025
Roof Replacement + Eaves, Soffits - Admin Bldg	$ 400,000
Whyte Ave Yard Streetlight pole replacement (x9)	$ 35,000
EV Charger Replacement	$ 25,000
Admin Building and Service Centre (Misc)	$ 45,000
Total	$ 505,000

2-SEC-17
Interrogatory:

[Ex. 2, pdf p. 347, DSP, Material Investment Narrative Fleet]
Please provide an update on the purchase of the single bucket truck in 2024. When is the scheduled delivery?

Response:
FHI has been informed by the manufacturer that due to a chassis delay, the bucket truck will now not be delivered until 2025.

2-SEC-18

Interrogatory:

[Ex. 2, pdf p. 366, DSP, Material Investment Narrative Enterprise Resource Planning Software Upgrade]

a) What is the status of the procurement of the ERP?
b) Did Festival Hydro explore a cloud-based solution for the ERP? If so, what was the result? If not, why not?
c) In Exhibit 4, page 21 shows a $162k increase in OM&A and includes additional costs for Service related to the planned ERP software. Please explain this in relation to the procurement of the ERP capital asset.

Response:

a) The ERP RFP received responses from three vendors and has received Board approval for the preferred solution partner. FHI is currently in contract negotiations with the selected solution provider, with a signed Master Service Agreement expected to be in place by the end of July. FHI will begin implementation immediately with a planned go live date in mid-2025.

b) The RFP did not specify a preference for on-premise or cloud-based. All solutions presented were cloud-based with a mix of SaaS and subscription components. Based on the selected proposal, implementation costs meet the IFRS requirements for capitalization.

c) See response to 4-Staff-31.

2-SEC-19
Interrogatory:

[Ex. 2, Appendix 2-AB, 2-D and 2-K]

	2015 actual	2025 application	Source
Total FTEs	43	45	2-K
Total Capex $	2,975,427	7,409,350	2-AA
Capital Allocated Compensation $	568,158	499,260	2-K
Allocated % of Compensation	12.7%	7.6%	Calculated from 2-K
Allocated OM&A $	963,420	1,281,468	2-D
Allocated % of OM&A	15%	12%	2-D

a) Please explain why Festival Hydro's total Capex increased from 2015 to 2025 by 2.5 times, yet the percentage of allocated compensation has decreased.

b) Please explain why the percentage of OM&A allocated to capital has decreased from 15% to 12%.

Response:

a) *A large portion of capital increases relate to non-distribution investments such as ERP, AMI etc. There are limited allocated labour costs for these projects compared to distribution projects. While most OM&A expenses increased during the period, labour related to O&M did not increase at the same rate as other costs.*

b) *See last sentence in response to a).*

EXHIBIT 3 – CUSTOMER AND LOAD FORECAST

3-SEC-20
Interrogatory:

[Ex. 3, Tables 3-10 and 3-13] Table 3-10 shows 2023 Actual Annual Usage per Customer and Table 3-11 shows the forecast using Table 3-10; however, it appears the numbers in Table 3-11 are not shown for the correct class. Please update as required.

Response:
FHI has updated Table 3-11 with the numbers shown for the correct class below:

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Large Use	Sentinel Lighting	Street Lighting	Unmetered Scattered Loads	Wholesale Market Participant
Forecast Annual kWh Usage per Customers/Connections								
2024 Bridge	7,437	28,890	1,707,170	29,085,391	2,792	369	1,617	1,542,415
2025 Test	7,437	28,890	1,707,170	29,085,391	2,792	369	1,617	1,542,415

3-SEC-21
Interrogatory:

[Ex. 3, Appendix 2-IB and Ex. 2, DSP, p.51] Page 51 of the DSP outlines the adjustments Festival Hydro has made due to the electrification of transportation for the purpose of asset planning. Exhibit 3 does not mention the electrification of transportation with respect to the load forecast.

a) Please explain what, if any, adjustments were made to the billing determinates for 2025 to reflect electrification of transportation.
b) If the response to a. is no adjustments are included, please propose an adjustment that is in keeping with the adjustment in the DSP.

Response:

a) While electrification of transport is anticipated to increase as discussed in the DSP, FHI has not seen a substantial uptake in recent years and expects similar trends to occur through the Test Year with increases to occur more rapidly in later years. The load forecast included in the Application aligns with current historical trends.

b) No adjustment is proposed based on response in a).

3-SEC-22
Interrogatory:

[Ex. 3, p. 3] Please provide an update on customer numbers to date for 2024, for each class.

Response:

See the average 2024 customer numbers to June 30, 2024, below:

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Large Use	Sentinel Lighting	Street Lighting	Unmetered Scattered Loads	Wholesale Market Participant	Total
Actual number of Customers/Connections as of June, 2024									
2024 Bridge	20,214	2,130	209	1	36	6,405	434	2	29,430

3-SEC-23

Interrogatory:

[Ex. 3, p. 20 and FHI_2025_Load_Forecast_Model_20240426]

a) Did Festival Hydro test any other variables such as population or economic indicators in its Power Purchased regression model? If so, what were the results? If not, why not?

b) Which variable(s) in the Power Purchased Model is capturing the impacts of CDM, as stated on page 20?

Response:

a. *FHI tested an Employment rate indicator, however, this variable did not result in a significant t Stat result.*

Statistic	Value
R Square	80%
Adjusted R Square	79%
F Test	64.9
MAPE (monthly)	2.1%
T-stats by Coefficient Intercept	1.1
Heating Degree Days	8.9
Cooling Degree Days	10.1
Number of Days in Month	4.6
Spring/Fall Flag	- 2.4
Number of Work Days in Month	4.6
COVID 19 Flag	- 10.0
Strat-Bruce Employment (000's)	1.4

b. *The impact of CDM programs is included in the past 10 years of purchased volumes.*

3-SEC-24

Interrogatory:

[Ex. 3, Table 3-16] Please confirm that the kW/kWh ratios shown at the bottom of Table 3-16 are not shown correctly for each class, and that the correct class ratio was used for each class.

Response:
Confirmed. Corrected table included below:

Year	General Service 50 to 4,999 kW	Large Use	Sentinel Lighting	Street Lighting	Wholesale Market Participant
Ratio of kW to kWh					
2014	0.2567%	0.1553%	0.2775%	0.2540%	0.1770%
2015	0.2561%	0.1588%	0.2778%	0.2578%	0.1752%
2016	0.2442%	0.1543%	0.2779%	0.2574%	0.1852%
2017	0.2447%	0.1510%	0.2781%	0.2366%	0.1823%
2018	0.2476%	0.1619%	0.2776%	0.2459%	1.0662%
2019	0.2481%	0.1511%	0.2780%	0.2685%	1.4566%
2020	0.2534%	0.1499%	0.2778%	0.2665%	0.8532%
2021	0.2497%	0.1477%	0.2784%	0.2673%	0.8918%
2022	0.2423%	0.1500%	0.2778%	0.2453%	0.3117%
2023	0.2451%	0.1478%	0.2778%	0.2432%	0.3250%
Ratios used in kW Forecasts					
	0.2488%	0.1528%	0.2778%	0.2542%	0.5624%

EXHIBIT 4 – OPERATING EXPENSES

4-SEC-25
Interrogatory:

[Ex. 4, Appendices 2-JA, 2-JD, and 2-K]

a) Please correct the information shown in 2-JA, columns T to W, lines 18 and 20, which should show total OM&A.
b) Please update Appendices 2-JA, 2-JC, 2-JD and 2-K for 2024 actuals year to date and provide actuals for the same point in 2022 and 2023.
c) Please provide the planned OM&A for 2016 to 2023.

Response:

a) *This has been completed and included in the updated Chapter 2 Appendices as part of this submission.*

b) *2-JA*

	June 30 Balances		
	2022 Actual	2023 Actual	2024 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
Operations	468,905	640,964	559,946
Maintenance	986,862	1,001,815	1,009,158
Subtotal	**1,455,767**	**1,642,778**	**1,569,103**
%Change (year over year)		**13%**	**-4%**
Billing and Collecting	655,895	669,615	761,139
Community Relations	-	-	-
Administrative and General	1,274,143	1,445,434	1,813,003
Subtotal	**1,930,039**	**2,115,048**	**2,574,142**
%Change (year over year)		**10%**	**22%**
Total	**3,385,806**	**3,757,827**	**4,143,245**
%Change (year over year)		**11%**	**10%**

	June 30 Balances		
	2022 Actual	2023 Actual	2024 Actual
Operations	468,905	640,964	559,946
Maintenance	986,862	1,001,815	1,009,158
Billing and Collecting	655,895	669,615	761,139
Community Relations	-	-	-
Administrative and General	1,274,143	1,445,434	1,813,003
Total	**3,385,806**	**3,757,827**	**4,143,245**
%Change (year over year)		**11%**	**10%**

2-JC

Programs	June 30 Balances		
	2022 Actual	2023 Actual	2024 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
Operations			
Engineering and Metering	331,971	376,667	273,950
Vegetation Management	94,365	72,656	79,862
Sub-Total	**426,337**	**449,323**	**353,812**
Maintenance			
Building Maintenance	70,863	73,548	83,503
Customer Related O&M	669,835	706,405	721,066
Stations O&M	118,482	225,946	227,486
System O&M	241,114	261,104	266,739
Sub-Total	**1,100,293**	**1,267,004**	**1,298,794**
Billing and Collecting			
Bad Debt	44,573	47,827	29,624
Customer Service, Billing, Collecting and Software	611,322	621,788	731,515
Sub-Total	**655,895**	**669,615**	**761,139**
Community Relations			
Community Relations and Safety	5,375	5,375	4,479
LEAP	14,550	15,000	15,630
Sub-Total	**19,925**	**20,375**	**20,109**
Administrative and General			
Administration, Third Party, Software & Communications	969,232	1,156,125	1,477,461
Insurance, Benefits and Employee Future Benefits	89,618	94,216	108,007
Regulatory	73,759	37,546	61,932
Property Taxes	50,747	63,622	61,991
Sub-Total	**1,183,356**	**1,351,510**	**1,709,391**
Total	**3,385,806**	**3,757,827**	**4,143,245**

2-JD

		June 30 Balances		
USoA	**Programs**	**2022 Actual**	**2023 Actual**	**2024 Actual**
	Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
5005	Operation Supervision and Engineering	102,280	138,360	107,052
5010	Load Dispatching	40,051	46,763	36,480
5012	Station Buildings and Fixtures Expense	17,204	19,733	20,099
5014	Transformer Station Equipment - Operation Labour	2,567	80,139	92,841
5015	Transformer Station Equipment - Operation Supplies and Expenses	43,119	48,480	29,029
5020	Overhead Distribution Lines and Feeders - Operation Labour	13,243	11,072	8,769
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	22,710	10,833	23,415
5035	Overhead Distribution Transformers - Operation		794	952
5040	Underground Distribution Lines and Feeders - Operation Labour	717	2,911	1,128
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expens	217	196	221
5055	Underground Distribution Transformers - Operation	2,778	4,384	7,734
5065	Meter Expense	119,288	152,602	96,324
5070	Customer Premises - Operation Labour	86,445	112,610	111,715
5075	Customer Premises - Materials and Expenses	5,623	4,759	4,373
5085	Miscellaneous Distribution Expense	8,870	3,320	15,418
5095	Overhead Distribution Lines and Feeders - Rental Paid	3,795	4,007	4,398
5110	Maintenance of Structures	4,042	13,159	5,922
5112	Maintenance of Transformer Station Equipment	11,499	17,672	20,329
5114	Mtaint Dist Stn Equip			22,787
5120	Maintenance of Poles, Towers and Fixtures	62,795	66,057	88,942
5125	Maintenance of Overhead Conductors and Devices	57,347	56,965	54,593
5130	Maintenance of Overhead Services	480,993	493,291	538,102
5135	Overhead Distribution Lines and Feeders - Right of Way	94,365	72,656	79,862
5145	Maintenance of Underground Conduit	15,589	21,629	15,857
5150	Maintenance of Underground Conductors and Devices	35,079	64,558	28,919
5155	Maintenance of Underground Services	96,774	95,745	66,876
5160	Maintenance of Line Transformers	17,975	14,378	16,394
5175	Maintenance of Meters	110,404	85,704	70,574
5305	Supervision	34,786	41,454	49,367
5310	Meter Reading Expense	114,756	115,697	122,926
5315	Customer Billing	333,898	326,111	360,385
5320	Collecting	63,786	65,611	97,490
5335	Bad Debt Expense	44,573	47,827	29,624
5340	Miscellaneous Customer Accounts Expenses	64,096	72,915	101,347
5605	Executive Salaries and Expenses	446,309	598,719	898,208
5615	General Administrative Salaries and Expenses	296,310	306,021	284,045
5620	Office Supplies and Expenses	102,373	102,320	98,168
5630	Outside Services Employed	59,249	67,366	131,447
5640	Injuries and Damages	22,030	26,357	29,901
5645	Employee Pensions and Benefits	67,588	67,860	78,106
5655	Regulatory Expenses	73,759	37,546	61,932
5665	Miscellaneous Expenses	64,991	81,700	65,594
5675	Maintenance of General Plant	70,863	73,548	83,503
5680	Electrical Safety Authority Fees	5,375	5,375	4,479
6105	Taxes other Than Income Taxes	50,747	63,622	61,991
6205	Donations - LEAP	14,550	15,000	15,630
	Total	**3,385,806**	**3,757,827**	**4,143,245**

2-K

	June YTD Actuals		
	2022	**2023**	**2024**
Number of Employees (FTEs including Part-Time			
Management (including executive)	11	12	12
Non-Management (union and non-union)	30	30	32
Total	**41**	**42**	**44**
Total Salary and Wages including overtime and incentive Pay			
Management (including executive)	661,087	818,373	1,070,477
Non-Management (union and non-union)	1,111,902	1,114,146	1,264,755
Total	**1,772,989**	**1,932,519**	**2,335,232**
Total Benefits (Current + Accrued)			
Management (including executive)	131,767	158,568	189,971
Non-Management (union and non-union)	324,484	367,236	435,828
Total	**456,251**	**525,803**	**625,799**
Total Compensation (Salary, Wages, & Benefits)			
Management (including executive)	792,854	976,941	1,260,448
Non-Management (union and non-union)	1,436,386	1,481,381	1,700,583
Total	**2,229,240**	**2,458,322**	**2,961,030**
Total Compensation Breakdown (Capital, OM&A)			
OM&A	1,957,185	2,182,402	2,548,878
Capital	272,055	275,920	412,153
Total	**2,229,240**	**2,458,322**	**2,961,030**

c) *2016 budget was not recorded in the ERP system however 2017 to 2023 is provided below.*

USoA	2017	2018	2019	2020	2021	2022	2023
5005	176,584	176,903	276,987	282,839	120,303	370,861	272,886
5010	51,254	54,936	55,298	63,225	64,693	75,209	86,885
5012	23,230	16,665	18,680	42,989	32,918	34,795	38,365
5014	740	1,158	4,553	2,322	7,872	8,116	149,979
5015	105,583	100,670	93,238	69,297	78,702	89,559	96,965
5016	101	84					
5020	12,486	13,098	12,857	13,756	24,129	24,933	27,693
5025	39,006	23,096	34,715	27,385	42,188	42,730	47,737
5035	6,869	5,151	12,688	8,753	8,533	7,276	6,372
5040	3,768	4,130	8,755	1,598	3,087	3,181	3,157
5045	256	182	315	311	311	306	429
5055	6,577	6,553	10,937	16,066	13,099	15,093	15,081
5065	317,456	323,035	285,660	331,132	445,718	309,149	262,677
5070	196,245	249,226	237,213	215,006	154,268	163,706	214,720
5075	8,106	9,552	4,295	6,972	6,330	6,032	7,538
5085	5,616	7,109	8,425	11,717	5,547	13,159	12,922
5095	7,834	10,330	5,358	8,680	9,085	12,381	9,905
5110	9,682	2,646	5,547	2,654	14,893	18,471	14,044
5112			30,000	2,500	31,211	25,375	25,375
5114	1,002	688		11,038	9,643	2,030	
5120	13,481	22,435	57,965	44,990	80,571	78,183	67,524
5125	81,449	91,582	114,193	107,768	109,079	114,981	117,340
5130	680,909	776,203	855,744	851,574	863,409	880,326	982,333
5135	175,000	189,510	131,211	147,756	160,865	167,291	177,052
5145	14,415	14,493	19,731	28,204	31,854	30,437	34,283
5150	96,439	105,569	92,685	118,075	69,305	78,188	80,329
5155	48,652	70,167	97,174	97,801	124,884	128,489	135,664
5160	17,933	17,195	16,459	26,928	29,886	26,151	30,201
5175	105,072	102,131	100,206	136,620	99,904	118,462	169,244
5305	44,592	26,267	82,455	82,093	86,045	57,240	68,724
5310	215,300	279,277	226,527	226,559	232,100	234,185	238,078
5315	604,269	616,032	589,113	628,523	672,304	747,529	708,859
5320	195,927	156,611	139,709	133,059	145,565	142,876	145,718
5335	90,946	92,000	92,000	92,000	89,145	89,145	89,145
5340	159,277	153,343	134,983	174,429	145,174	157,823	150,564
5405	1,453	1,320		1,005	1,030	1,046	1,132
5420	8,820	11,362	11,843	9,139	7,598	7,555	8,107
5605	729,423	827,001	918,756	994,722	1,055,579	1,307,467	1,465,542
5615	575,900	470,633	473,197	493,341	522,154	571,617	624,771
5620	202,938	196,320	204,293	194,233	201,933	231,940	227,216
5630	61,814	180,399	127,006	151,783	207,500	158,743	181,782
5640	46,630	46,603	42,010	51,586	54,180	47,144	78,978
5645	101,260	112,277	125,250	129,135	142,000	142,890	148,237
5655	164,801	136,791	149,440	123,825	114,200	135,538	186,308
5660	20,000						
5665	56,424	88,673	102,709	99,997	98,893	113,908	115,763
5675	153,871	154,391	156,183	159,167	151,200	132,392	170,134
5680	10,639	11,390	10,587	10,587	11,000	11,000	11,000
6105	7,004	6,815	6,565	6,333	6,500		
6205	63,600	63,660	69,074	64,000	65,000	64,225	50
	5,720,634	6,025,662	6,252,591	6,503,473	6,651,387	7,199,131	7,706,807

4-SEC-26
Interrogatory:

[Ex. 4, Appendix 2-M]

a) Please provide details on the work that was performed, the cost and the year for the $136,460 shown in cell E17.
b) Please provide details on the work included in the forecasted $138,540 in cell F17.

Response:

a) See table below.

Regulatory Specialist Consulting	*50,962*
Financial Model Review and Assistance	*9,338*
ACA Third Party	*38,000*
DSP Third Party	*18,912*
Customer Engagement	*19,248*
	136,460

b) See table below.

Regulatory Specialist Consulting	*51,705*
Financial Model Review and Assistance	*27,587*
DSP Third Party	*59,248*
	138,540

Based on current results, FHI has exceeded this amount based on response in 2-Staff-30.

4-SEC-27
Interrogatory:

[Ex. 4, p. 13] Please provide a list of software that has moved from an in-house capital asset to a cloud-based solution, in the years 2015-2025.

Response:

The following applications moved from an in-house capital asset to a cloud-based solution, in the years 2015-2025:

- *Microsoft Exchange on-premise moved to Microsoft 365*
- *Daffron CIS moved to hosted Jomar CIS platform.*
- *ERP will move from IXP to a cloud platform.*

FHI has not included movement from capital to subscription for on-premise solutions as these are not cloud based but are still ongoing OM&A costs instead of capital.

4-SEC-28
Interrogatory:

[Ex. 4, p. 21 and 29]

a) ERP software is included in Festival Hydro's capital plan as an asset at $875k for 2024 and 2025. Please explain the increase in Software Support and Maintenance Costs for Software as a Service related to the planned ERP software.
b) CIS upgrade was also included in Festival Hydro's capital plan as an asset in 2022 and 2023. Festival Hydro explained the increase in Customer Service, Billing, Collecting and Software from 2023 to 2025 as partly due to the billing function being outsourced, which increased contract labour and additional funds for CIS hosting, whereas the previous solution was on premises and an additional billing position.
   i. Please explain what is meant by the CIS not being on premises when it is an asset of Festival Hydro.
   ii. Please explain why Festival Hydro outsourced billing when it was more expensive.
   iii. Please explain why

Response:

a) The costs for Software as a Service related to ERP are $13,131 annually. This includes Core Financials and Accounts Payable automation. The increase in these software support and maintenance costs were considered during the RFP process, which received both software as a service and on-premise responses. Software as a service proved to be the more cost-effective option. The remainder of the ERP operating expenses are related to professional services support and subscriptions for extended capabilities including HR, time reporting and budgeting. The total for all SaaS, subscriptions and support total $184,052 in OM&A costs. This total included $90K annually for support, in the Test Year only 50% was included based on the anticipated implementation date.

b)
   i. CIS will be hosted by the software provider, Jomar Softcorp. The chosen delivery model from Jomar involves deploying a dedicated hosted environment for the asset, namely the CIS application and database. This hosted CIS environment is securely integrated with on premises systems such as AMI, GIS, etc. Having the CIS environment hosted removes the need for specialized hardware and support like FHI had with the Daffron system.
   ii. FHI did not outsource billing. FHI outsourced the printing of bills and the hosting of the CIS. FHSI performs IT related services for the CIS. All billing is completed by FHI.

iii. As noted in ii) FHI did not outsource billing.

4-SEC-29
Interrogatory:

[Ex. 4, p. 27, Appendix 2-K]

a) Performance Pay was introduced in 2023 for the Executive Leadership Team. Please provide the details for the determination of the amount of performance pay for 2023 to 2025.
b) What amount of performance pay was included in 2023, and what has been forecasted for 2024 and 2025 in Appendix 2-K?

Response:

a) The eligible amount of performance pay for 2023 was based on a P50 level as measured against the comparators. It is expected to be similar in 2024 and 2025. The amount of performance pay awarded is based upon overall company performance as well as the executive's own individual performance.

b) Please see 4-Staff-20 (f).

4-SEC-30
Interrogatory:

[Ex. 4, p. 20, Appendix 2-K]

a) Please explain the increases in compensation/FTE from 2023 to 2024 for Management (21%) and Non-management (15%).
b) Please provide copies of the internal compensation review for non-union staff and the external compensation review for executive staff, which the evidence refers to.
c) Please provide the number of vacancies in each year for 2015 to 2023.

Response:

a) Please see 4-Staff-20 (i) for management. Non-management increased by most of the same reasons. Union employees pay were bound by the union agreement for increases however benefits and step increases would increase this amount.

b) Please see 4-Staff-20 and 4-Staff-21.

c) See below.

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Vacant Positions	0.75	1.67	0.50	0.42	0.25	1.25	1.92	0.67	1.67

Please note that these numbers do not account for positions that are duplicated for a portion of the year to train before a planned departure such as a retirement.

The majority of the vacancies noted between 2020 and 2023 were senior leadership roles which have taken longer to fill. So far in 2024, FHI is aligning with vacancy rates from 2017-2019.

4-SEC-31
Interrogatory:

[Ex. 4, p. 48] Which employees does FHI share with the affiliate FHSI and what is the percentage of time each employee spends with each company?

Response:

Position	# of Hours / Month
CEO	4
CFO	10
VP IT	20
Mgr. People & Safety	7.5
Mgr. Finance	2
Financial Analyst	8
Accounting Specialist	6
Accounts Receivable Specialist	8
	65.5

4-SEC-32
Interrogatory:

[Ex. 4, Appendix 2-JD]

a) Please provide details on which USoA account Festival Hydro records its locate costs and totals spent each year between 2015 and 2023.
b) What amount is forecasted for locates in 2024 and 2025?
c) Please confirm that Festival Hydro is not requesting use of the generic Getting Ontario Connected Act account established by the OEB.

Response:

a) *FHI's locate costs are captured under USoA account 5070.*

Based on historical tracking of time and Work Orders, FHI is unable to accurately break out costs dedicated to locating for the years 2015-2017, however actuals for 2018-2023 have been provided, as well as budget forecasts for 2024 and 2025.

	2018	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***
Locate Costs	*$240,647*	*$202,222*	*$169,998*	*$198,737*	*$208,473*	*$201,969*	*$214,382*	*$222,109*

b) *Please see the above table in (a.) for the 2024 and 2025 budget forecast.*

c) *Confirmed.*

EXHIBIT 5 – COST OF CAPITAL AND CAPITAL STRUCTURE

5-SEC-33
Interrogatory:

[Ex. 5, p.11, Appendix 2-OB] For the new loan Festival Hydro plans to take out effective January 1, 2025:

a) Please reconcile the term as Exhibit 5 says 10 years while Appendix 2-OB says 25 years.
b) Please explain why the interest rate for the planned December 31, 2024, $5M swap loan is 4.02%, and for the January 1, 2025, loan of $5M is 6.05%.
c) Did Festival Hydro investigate obtaining one loan instead of two, with the lower interest rate? If so, please provide details.

Response:

a) *Swap Loan # 2 has a 10-year term, 2-OB has been corrected.*

b) *The interest rate for the Swap loan starting on December 31, 2024, was locked in as a forward fixed rate in late 2021 to take advantage of low interest rates at the time. The January 1, 2025, loan rate is based on an estimate from RBC in February 2024.*

c) *When the Swap loan was investigated in 2021, FHI did not want to request more funds than it needed. Also, at that time FHI was not aware that its CIS and ERP systems would no longer be supported and would need to be replaced.*

EXHIBIT 6 – REVENUE REQUIREMENT AND REVENUE DEFICIENCY OF SUFFICIENCY

6-SEC-34
Interrogatory:

[Ex. 6, p .21 and Ex. 8, Table 8-10] Exhibit 6 states that "FHI has not proposed any new specific service charges or incorporated new rates or rules that would impact Other Revenue." Table 8-10 shows that the charges for Service Call – Customer Owned Equipment and Service Call – After Regular Hours are proposed to go from $30 and $165 respectively to Time & Materials. Below Table 8-10 (p.13) Festival Hydro states 'Specific Service Charges are recorded in USoA 4225 and 5235 which are included in Table 6-13.'

a) Please confirm that the reference should be to Table 6-16 and the USoA reference should be 4235, Miscellaneous Revenue. Please explain the reference to USoA 5235.
b) Please explain why the change from a fixed charge to Time & Material would not impact Other Revenue.
c) Please provide any analysis done to determine what the revenue would be from these Time & Material charges.

Response:

a) *Confirmed that USoA 5235 is a typo and should have been USoA 4235.*

b) *Based on response to c) below and 4-Staff-42, FHI has adjusted account 4235 by $12,624 to account for expected additional revenue.*

c) *See chart below.*

	# 2023 Call	% per cost estimate based on response to 8-Staff-42	$ Charge	Cost x % based on 2023	
For a Service Call – Customer Owned equipment	35	20%	-	-	
		70%	175	4,288	
		10%	1,000	3,500	
For a Service Call – After Regular Hours	73	10%	175	1,278	
		80%	350	20,440	
		10%	1,000	7,300	
	Total anticipated time & materials			36,805	
	Mark Up (25% + 9.3%)			**12,624**	**Added to USoA 4235**

EXHIBIT 7 – COST ALLOCATION

7-SEC-35
Interrogatory:

[Ex. 7, Tables 7-2 and 7-4] Please provide the backup data and analysis that was used to calculate:

a) Weighting Factor for Billing and Collection in Table 7-2
b) Weighting Factor for Meter Reading in Table 7-4, specifically the 22.89.

Response:

a. *See 7-Staff-37.*

b. *FHI Calculated a meter reading cost per rate class, followed by a meter reading cost per customer. FHI assigned a weighting of 1.0 to residential and GS < 50kW. FHI divided the Cost per customer for the remaining rate classes by the cost per customer for the Residential and GS < 50 kW rate classes to arrive at the weighting of 22.89. Tables depicting FHI's analysis are included below:*

Billed Month	MDM/R Billed Smart Meters	Interval Meters
January	$ 3,562	$ 730
February	$ 3,560	$ 633
March	$ 3,560	$ 582
April	$ 3,555	$ 508
May	$ 3,553	$ 958
June	$ 3,552	$ 490
July	$ 3,556	$ 490
August	$ 3,554	$ 485
September	$ 3,553	$ 483
October	$ 3,544	$ 487
November	$ 3,547	$ 487
December	$ 3,459	$ 512
Total Cost	**$ 42,556**	**$ 6,845**

	Total Cost	Cost Per Customer	Weighting
Residential & GS<50 kW	$ 40,428	$ 1.85	1.00
GS 50 to 4,999 kW, Large Use &WMP	$ 8,973	$ 42.32	22.89

EXHIBIT 8 – RATE DESIGN

8-SEC-36
<u>Interrogatory:</u>

[Ex. 8, Table 8-5] Please explain why Festival Hydro has proposed to increase the Monthly Service Charge for the classes, GS < 50 kW, GS 50 to 4,999 kW, Large Use and Unmetered Scattered Load, above the Fixed Charged Ceiling from the Cost Allocation Model given by the OEB's guidance to not increase fixed charges above the ceiling.

<u>Response:</u>
FHI proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges. This proposal is consistent with Ontario Energy Board's ("Board") Decisions in numerous proceedings, including:

- *North Bay Hydro Distribution Ltd. – 2021 Cost of Service (EB-2020-0043)*

Also, On April 2, 2015, The OEB released the Report of the Board: A New Rate Design for Electricity Residential Customers (EB-2012-0410) and determined that residential distribution rates would move to a fully fixed monthly charge. On February 21, 2019, Board Staff released the Report to the Board: Rate Design for Commercial and Industrial Electricity Customers - Rates to Support an Evolving Energy Sector (EB-2015-0043). Within that report Board staff recommended a fully fixed monthly charge for a new General Service Less than 10 kW class.

The monthly peak load of Residential customer is generally less than 10 kW. Based on the above two reports there appears to be a consistent position to a movement to a fully fixed monthly charge for those customers who have a monthly peak load less than 10 kW which would also apply to the Street Light, Sentinel Light and Unmetered Scattered Load classes. As a result, FHI submits it is reasonable to propose maintaining the fixed/variable split until the initiative for Rate Design for Commercial and Industrial Electricity Customers is completed.

8-SEC-37
<u>Interrogatory:</u>

[Ex. 8, Table 8] Some of the numbers in Table 8.23 do not agree with the Bill Impact Model. For example, for GS > 50 kW Distribution, Table 8.23 shows 5.54% and the Bill Impact Model shows 2.34%. Please explain and update as required.

<u>Response:</u>
FHI does not have a Table 8.23 in its Application and is unable to follow and complete this question.

8-SEC-38

Interrogatory:

[Ex. 8, Table 8-8] The application states “FHI has amended the RTSR for gross load billing” Please provide details of the changes that were made and the impact on the two customers. Please provide details of any communications Festival Hydro has had with the two customers who will be affected by this change.

Response:

Please see 1-AMPCO-3(a) for the requested information.

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9-SEC-39
Interrogatory:

[Ex. 9, Table 9-5] Footnote 2 on page 6 of the Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications states that "The previous $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million still applies to other applications of the materiality threshold, e.g., DVAs, Z factor and eligible investments for the connection of qualifying generation facilities." Table 9-5 shows that, each of the annual entries for the OEB Cost Assessment DVA subaccount is less than $50,000.

a) Please explain why Festival Hydro believes these balances should be approved for disposition given the annual amounts are below its materiality threshold.
b) Since Festival Hydro chose to defer its rebasing from 2020 to 2025, please explain why it should recover the funds recorded in this subaccount for the years 2020 to 2024.

Response:

a) *The cumulative impact of this change is material to FHI and has been granted in other LDC rate applications. Even if FHI had rebased in 2020, the cumulative variance would have been material.*

b) *The higher expense as a result of this change would have been incorporated into its rebasing Application regardless of the year that rebasing occurred. As per the letter dated February 9, 2016, "Entries into the variance accounts are to be made on a quarterly basis when the OEB's cost assessment invoice is received. Amounts should be prorated to take into account the effective date of rebased/reset rates, payment amounts or fees (as applicable). Regulated entities are to cease recording amounts in these accounts when their rates, payment amounts or fees (as applicable) are rebased/reset (cost of service or custom IR) incorporating an updated forecast of cost assessments." The letter does not state a timeline on rebasing.*

VULNERABLE ENERGY CONSUMERS COALITION (VECC) INTERROGATORIES

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-1
Interrogatory:

Reference: Exhibit 1, page 34

a) What are the individual costs of the Oraclepoll customer engagements?

b) What was the cost of the Brickworks Communication customer engagement?

Response:

a) $4,900.

b) $19,248.

1-VECC-2
Interrogatory:

Reference: Exhibit 1, page 38

In addressing its outlier performance on Metering O&M FHI states:

"*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*."

a) In what way is FHI different from other utilities which are required to meet the same federally mandated meter performance standards?

b) FHI states is has "*hundreds of non-communicating meters*". On an annual basis what is the percentage of bills provided on the basis of an estimated meter read?

Response:

a) FHI is not fundamentally different from other utilities in that the same federally mandated meter performance standards are required to be met. However, concerning AMI meter condition, FHI is not aware of other utilities needing to *send back 2-3% of their installed meter population each year in order to meet these federally mandated meter performance standards.*

b) *Please see below for the requested information.*

	2021	***2022***	***2023***
# of walk reads	*1,493*	*5,916*	*9,092*
# of bills sent out	*274,486*	*278,307*	*280,731*
% based on walk reads	*1%*	*2%*	*3%*

However, please note that because FHI manually reads these meters each month to collect information on monthly kWh consumption, the actual consumption is not estimated, and consumption profiles are used in billing the customers.

1-VECC-3
Interrogatory:

Reference: Exhibit 1, page 46

"*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."*

a) Please confirm that no costs related to FHI's investments in renewable generation are included in the calculation of the proposed distribution rates?

Response:

a) *Confirmed.*

1-VECC-4
Interrogatory:

Reference: Exhibit 1, Attachment 1-7 Conditions of Service

FHI's posted Conditions of Service contain the following two reasons for disconnect:
h) Overdue amounts payable to Festival Hydro for the distribution or retail of electricity or for a security deposit.
o) Where the Customer owes Festival Hydro money for distribution services, an expansion deposit or security deposit;

a) What is the difference in these two reasons for disconnect?

b) The latter condition ("o") is not limited to amounts being "overdue". At any given time, a customer may "*owe Festival Hydro money for distribution services*". Are customers who are in arrears of a month subject to disconnection?

c) What are FHI's customer bill reminder policies?

Response:

a) *Condition "h" relates to overdue amounts on a customers electricity bill, while condition "o" relates to unpaid amounts for work that was completed to provide a distribution service/connection to a customer.*

b) No, this is not for billing arrears, this is where the customer did not provide adequate payment for the connection of a distribution service.

c) FHI follows the schedule for bill reminders, as laid out in the Customer Service Rules, by the Ontario Energy Board, most recently updated on March 5, 2020. https://www.oeb.ca/newsroom/2020/new-ontario-energy-board-customer-service-rules-strengthen-consumer-protection

1-VECC-5
Interrogatory:

Reference: Exhibit 1, Attachment 1-7 Conditions of Service

FHI's posted Conditions of Service contains this reason for disconnect:
d) A material decrease in the efficiency of Festival Hydro's Distribution System.

a) What is contemplated by this reason for disconnect. Please provide examples of the types of conditions that would need to exist for this reason for disconnect to be implemented.

Response:

a) This reason for disconnecting is to ensure that FHI has recourse should a customer install equipment that degrades the power factor or increases distribution losses of FHI at a distribution system level and a mutually acceptable resolution is unable to be found.

An example of this types of condition would be:

- *Power factor at an IESO wholesale point is degraded below market rules, putting FHI in non-compliance and potential fines, with a main cause being a customer's equipment, and no resolution to the problem being found.*

1-VECC-6
Interrogatory:

Reference: Exhibit 1, Attachment 1-7 Conditions of Service

FHI's posted Conditions of Service section 2.3.2.4 states in part:
Whenever practical and cost effective, as determined by Festival Hydro, arrangements suitable to the Customer and Festival Hydro will be made to minimize any inconvenience. Festival Hydro will endeavour to provide the Customer with reasonable advance notice of a planned interruption.

a) Please provide FHI's written policies on customer notification for planned outages.

Response:

a) FHI does not have a written policy on customer notifications in addition to what is stated in the Conditions of Service. Typically, FHI updates template letters to inform affected customers when a planned interruption will take place, including information such as the duration, potential rain date, and contact information.

These letters are then delivered to all affected customers in advance of the outage.

1-VECC-7
Interrogatory:

Reference: Exhibit 1, Attachment 1-7 Conditions of Service

a) Section 2.4.5.3 sets out the payment options for customers. While FHI offers pre-authorized bank payment it is not clear whether the option is available for a customer to list FHI as a payee in their on-line account banks (i.e. not preauthorized payments but payment as selected by customer from a list of banks payees). Please clarify if this form of payment is available to customers.

b) What is the third-party fee for Visa and Mastercard payment. If a customer chooses electronic billing is this fee waived?

c) On an annual basis for the latest 12 months please provide the percentage of bills paid by the different methods listed (i.e. 'a' through 'e').

Response:

a) Yes, FHI customers are able to add Festival Hydro as a payee through their bank.

b) FHI customers wishing to pay their bill by credit card (not limited to Visa or Mastercard) can do so through Paymentus. Customers are charged a service fee *of 2.5% on the transaction by Paymentus, at the time they make their payment. FHI does not offer pre-authorized payment via credit card.*

c) *This information is not tracked by FHI.*

1-VECC-8
Interrogatory:

Reference: Exhibit 1, Attachment 1-11 Business Plan, page 16

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

a) Please update the above table to include 2023 results.

Response:
a) *These results are not yet available on the draft scorecard.*

1-VECC-9
Interrogatory:

Reference: Exhibit 1, Attachment 1-13, 2022 Audited 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			

a) What accounts for the large increase in Bank indebtedness as between 2021 and 2023?

Response:
a) *There are a few reasons for the increase:*
   1) Higher capital program specifically relating to building renovations.
   2) Higher cost of power invoice paid in December 2023 compared to 2021.
   3) Increase in regulatory asset balance in 2023 compared to 2021.

1-VECC-10
Interrogatory:

Reference: Exhibit 1, Attachment 1-16, Scorecard

a) Please update FHI's Scorecard to include 2023 outcomes.

Response:

a) The 2023 Preliminary Scorecard has been included as Attachment 9.

1-VECC-11
Interrogatory:

Reference: Exhibit 1, Attachment 1-16, Scorecard

a) FHI last filed its last cost of service rates in 2014 based on a 2015 test year. The typical IRM period for FHI therefore expired on the rate year of 2019. Typically, this would have resulted in FHI filing for 2020 rates in early 2019. Please explain why the utility deferred filing for new cost of service rates prior to the COVID pandemic and why it continued to defer rate rebasing subsequent to the COVID pandemic.

b) Please file each request for deferment and the Board's response to that request.

Response:

a) FHI cannot speak to prior management's decisions to delay prior to the pandemic. FHI's current executive team determined that a Cost of Service was necessary and began early stages of planning in 2021. It was determined that a realistic timeframe based on labour resources was for January 1, 2025, rates.

b) Please see documents in Attachment 13.

EXHIBIT 2 – RATE BASE AND CAPITAL

2-VECC-12
Interrogatory:

Reference: Exhibit 2, Attachment 2-2 DSP, 5.4 (Appendix 2-AB)

a) Please explain how the capital contribution forecast of $327k for 2025 was derived.

b) What are the actual capital contributions received or billed in 2024 to date?

Response:

a) *The 2025 capital contribution forecast was derived using a combination of historical data as well as expected projects in 2025.This included:*

- *A municipally road relocation project of Highway 83 in Dashwood, for which the Public Service Works on Highways Act is being used to estimate a contribution of $47,000.*
- *New services for subdivision connections and service upgrades, which is estimated at $131,000. This is based on historical capital contributions from service upgrades and the number of new services forecasted to be installed, based on available subdivision lots.*
- *New subdivisions, based on the build of three subdivisions identified after discussions with developers and based on information available which is estimated as follows:*
-

Thames West Phase 2: $81,900
Thames Crest Phase 2B: $125,500
520/525 Orr: $199,500

- *Rebates to Customers for subdivisions and expansions, including:*
Totaling -$257,700

Project	***Capital Contributions***
Highway 83 Dashwood	*$47,000*
New Services	*$131,000*
New Subdivisions	*$406,900*
Rebates	*$-257,700*
Total	*$327,200*

b) *The latest actual capital contributions billed are $157,249, based on June 30, 2024.*

2-VECC-13

Interrogatory:

Reference: Exhibit 2, Appendix A – Narratives - Metering

a) Are meters purchased under the Metering Program (200k in 2024 and 112k in 2025 compatible with the AMI 2.0 program. If not, what steps are being taken to minimize any "crossover" meter requirements?

Response:

a) *In 2024 and 2025, all meters for residential and GS<50 customers will be compatible with the AMI 2.0 program and will be purchased under that program.*

All instrument transformers and metering configurations will also be compatible with the AMI 2.0 program and meters intended to be purchased under it.

All other meters for larger commercial and industrial customers, historically less than 10 per year, and instrument transformers, installed and purchased under this program will be part of FHI's MV90 system that is not planned to be part of FHI's mesh network, and these meters are intended to be used for its full-service life.

2-VECC-14
Interrogatory:

Reference: Exhibit 2, Appendix A – Narratives – New Services/ Subdivisions

a) Please explain the distinction between "new services" category of spending and that of "subdivisions"

b) Please provide the current status of the three subdivision projects for 2025 (Thames West Phase 2, 520/525 Orr and Thames Crest Phase 2B). Specifically indicate the current and expected date for lot preparations, road layout and electricity plant installation and energizing of circuits.

Response:

a) *New Services encompasses requests for new/upgraded services from customers and developers. This includes secondary connections in subdivisions, in-fill lots, new commercial services, service upgrades to existing residential and commercial customers.*

Subdivisions encompasses costs for installing the civil work, transformers, and primary infrastructure for new developments.

b) *520 Orr – lot preparations/road layout have started in Q3 2024, electrical plant installation and energization – Q1 2025*

525 Orr – lot preparations/road layout – Q2 2025 – electrical plant installation and energization is expected follow in Q4 2025

Thames Crest Phase 2B – lot preparations/road layout – Q1 2025, electrical plant installation and energization – Q3 2025

Thames West Phase 2 (This is under new ownership now and is being called Festival West) - lot preparations/road layout – Q2 2025 – electrical plant installation and energization would be Q4 2025

2-VECC-15
Interrogatory:

Reference: Exhibit 2, Appendix A – Narratives – AMI 2.0

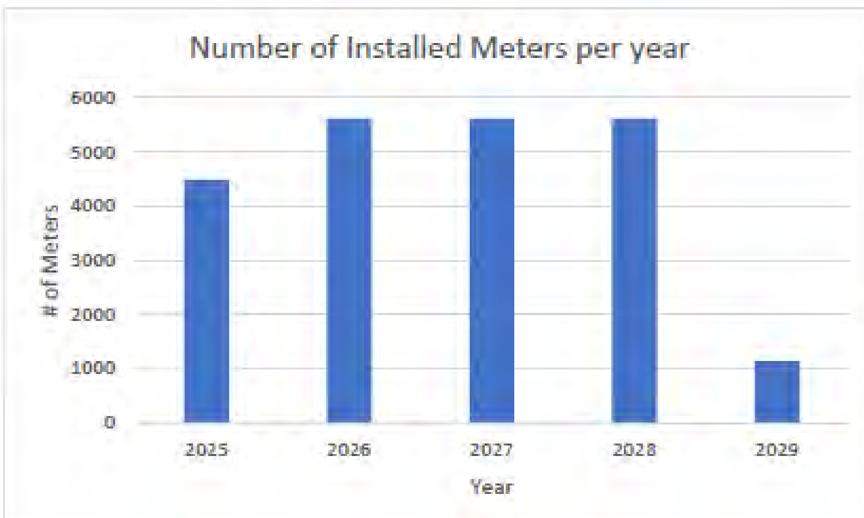


Figure 1: Yearly Meter Deployment Plan

a) Did FHI undertake an AMI review/implementation study? If yes, please provide that study.

b) When are the results of the AMI 2.0 Pilot expected to be provided?

c) What is the cost of the AMI pilot? How many meters are expected to be installed?

d) Please provide the GNATT chart(s) showing the timelines and milestones for this project.

e) What would be the cost reduction in 2025 if only half of the expected AMI 2.0 meters are installed in 2025?

f) What is the expected life of the new AMI 2.0 meters?

Response:

a) *FHI did not complete an AMI review/implementation study. FHI identified the need to replace their existing AMI network for the numerous reasons outlined in Exhibit 2, Appendix A – Narratives – AMI 2.0. As part of the comprehensive RFP process, FHI requested proposed implementation project plans from all vendors which included, at a minimum:*

-Identify all tasks to integrate the AMI into the Utility's production environment, including hardware/software installation, configuration of the software, user training, testing, and cut-over to production.

-Be separated into phases (e.g., initiation, planning, execution, closeout)

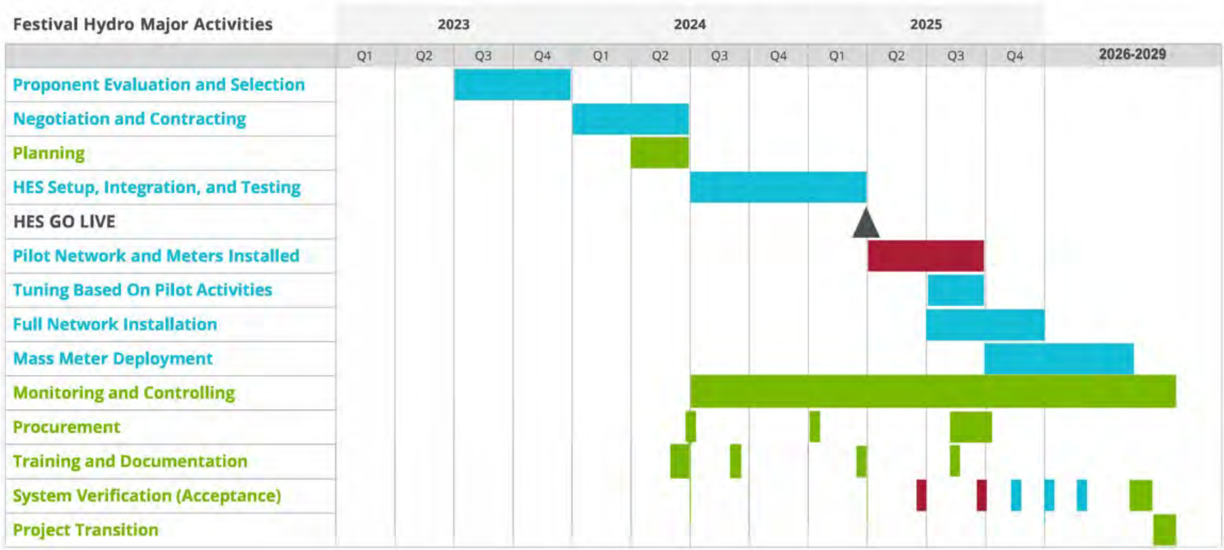
-Identify all testing activities (test plan development, test script development, testing support, test results, etc.) and testing phases (unit, system, integration, user acceptance, etc.).

This assisted FHI in understanding the vendors proposed implementation methodologies and plans, as well as the proposed timing to assist in developing the implementation timeline.

b) *FHI expects the results of the AMI 2.0 Pilot to be ready in Q2 of 2025.*

c) *The number of meters expected to be installed is 600. The cost of the AMI pilot is estimated to be $160,000 to purchase the meters and network equipment, as well as install the devices.*

d) *The latest GANTT chart is shown below, however as FHI and their selected vendor move through the planning stage this chart will continue to be updated and refined.*



e) *The cost reduction in 2025 if half the AMI meters are installed would be approximately $600,000. However, extending the AMI installation lengthens the time that FHI must allocate costs and resources to maintaining two Head End Systems, delays the benefits that AMI 2.0 brings to its customers, and requires AMI 1.0 meters that are past their expected service life to remain installed, as their conditions continue to degrade.*

f) *The vendor has indicated that the expected life of the new AMI 2.0 meters is 20 years.*

2-VECC-16
Interrogatory:

Reference: Exhibit 2, Appendix A – Narratives – Underground Renewal (PDF 310)

	2018	2019	2020	2021	2022	2023
Km of cable replaced	3.5	2.3	2.9	2.5	5.5	1.3

a) Please amend the above table to show the average cost per km installed and include the years 2024 and 2025 (forecast).

b) If FHI's UG Renewal program were reduced to its 2024 level of spending in 2025 what projects would be deferred?

Response:

a) The below table has been updated to reflect the cost/km and 2024 through 2025 years.

	2018	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***	***2025***
Km of cable replaced	*3.5*	*2.3*	*2.9*	*2.5*	*5.5*	*1.7*	*4.3*	*4.4*
Cost/km ($ '000)	*$121.7*	*$183.5*	*$125.9*	*$176.4*	*$128.7*	*$318.8*	*$188*	*$270*
Length of Duct Installed	*30m*	*0m*	*8m*	*30m*	*0m*	*880m*	*260m*	*1km*
Number of Tx installed	*10*	*2*	*1*	*1*	*0*	*9*	*15*	*17*

As highlighted in FHI's Materiality Narrative "Underground Renewal" in historical years (including 2024) many of the projects FHI completed only involved the replacement of cable, requiring only minimal civil work and transformer replacements. With the main exception being 2023, however that lead to a significantly lower amount of underground cable being replaced. FHI has also updated the km of cable replaced in 2023, as a data error occurred, this number has been updated to reflect actuals.

Beginning in 2025, FHI plans to balance investments in this area by completing projects that replace cable in duct, and those that are not in duct, or suitable mechanical protection, or those that are not looped as per current industry practice. The effect of that is that the cost/km increases as in FHI's experience, civil work can be up to half the cost of the entire project, so while in 2024 and 2025 the amount of cable being replaced is the same, 2025 sees 750m more duct being replaced.

Furthermore, from 2021 to 2023 FHI saw an increase of 36% to install primary underground cable, the majority of which is driven by material cost increases.

b) *If FHI was forced to reduce UG renewal spending to 2024 level (equating to a reduction of $379,000) the following projects would be deferred.*

- *Barron St. Townhomes*
- *Ingersoll St. Switchgear cable replacement*
- *A portion of Maxwell St. would be reduced to meet the remainder of the reduction*

The impact of this would be approximately 1km of cable identified by the ACA as being in poor condition would not be replaced. It also would prevent the planned switchgear replacement on Ingersoll St of an asset deemed in very poor condition.

Furthermore, it prevents the looping of the primary distribution network in the Barron St. townhomes area until the project is completed and prevents Maxwell

St. from having additional transformers added and customers balanced between transformers as FHI plans for the increased demands expected of the distribution system due to residential electrification.

2-VECC-17
Interrogatory:

Reference: Exhibit 2, Appendix A – Narratives – Buildings

a) Given the age, condition and location of the current FHI buildings what consideration was given to moving to a new location(s)?

b) Please itemize the $2.165 in 2024 and $505k in 2025 that is being spend on building (material categories of $100k or more).

Response:

a) Please see the above Referenced Narrative, Section A5 "Comparative Historical Expenditures" for information regarding the different options FHI considered prior to renovating the existing building.

b) In 2024, the following projects were budgeted for:

- *1st Floor Renovation Total budget: $1,200,000*
  - *Doors and Windows: $123,630*
  - *Finishes (ceilings, drywall, paint, floor): $177,450*
  - *Mechanical (HVAC and Plumbing): $271,400*
  - *Electrical/Data: $172,500*

  The remainder of the items are all under $100,000 but includes costs such as architectural and engineering drawings, furniture, demolition, cabinetry/appliances.
- *2nd Floor Renovation Total budget: $940,000*
  - *Doors and Windows: $137,730*
  - *Finishes (ceilings, drywall, paint, floor): $165,359*
  - *Mechanical (HVAC and Plumbing): $125,350*
  - *Electrical/Data: $123,050*

  The remainder of the items are all under $100,000 but includes costs such as architectural and engineering drawings, furniture, demolition, cabinetry/appliances.

In 2025, The only project above $100,000 budgeted under buildings is to replace the administration building roof based on the 2023 third party report, which is budgeted at $400,000 based on a 2023 quote.

2-VECC-18

Interrogatory:

Reference: Exhibit 2, Appendix A – Narratives - Fleet

a) Please list the type and cost of each vehicle being replaced in 2024 and 2025. Please indicate what vehicles have already been purchased and at what cost.

Response:

a) *In 2024, a 42' single bucket truck was budgeted to be replaced. Following a competitive tender process, this truck was purchased in 2022 for $435,000.*

   Since FHI's Application was completed, the bucket truck delivery has been moved into 2025 based on a delay in the chassis delivery. It is now estimated that the chassis will be delivered in October 2024, but the body and aerial installation, and final delivery of the truck will not take place until 2025. FHI expects to pay for the chassis in 2024, with the remainder of the costs now moving into 2025.

   In 2025, the 1985 forklift and 2013 pickup truck were planned to be replaced.

   $55,000 was budgeted for the forklift, and following a competitive RFQ process has been purchased for replacement for $53,000.

   $70,000 was budgeted for the pickup truck and is currently undergoing a competitive RFQ process.

EXHIBIT 3 – CUSTOMER AND LOAD FORECAST

3-VECC-19
Interrogatory:

Reference: Exhibit 3, page 6, Table 3-2

a) Please explain how the Billed Weather Normal values were derived.

Reference: Exhibit 3, page 7, Table 3-3

a) Please confirm that the counts for Street Lighting are based on number of devices and not number of connections as suggested in the Table's title.

Response:

a) The weather normal values are the actual values adjusted by the weather normal conversion factor displayed in Exhibit 3, Page 12, Table 3-6. The weather conversion factor is determined consistent with the approach outlined by the OEB Appendix 2-IA.

a) Confirmed.

3-VECC-20
Interrogatory:

Reference: Exhibit 3, page 9
Load Forecast Model, Inputs Tab

Preamble: The Application states:

"*FHI notes that Purchases from the IESO were adjusted by Long-Term Load Transfers (until cessation in 2017), Embedded Generation, and Wholesale Market Participant data*".

a) It is noted that the LTLT are positive in the years 2014-2016 but negative in 2017. Please explain what led to the change in 2017.

b) Was the Wholesale Market Participant (WMP) data adjusted for losses or are the values used the kWh delivered to the WMP?

Response:

a) FHI had Long Term Load Transfers to and from Hydro One Networks Inc. (HONI) from 2014-2017. In 2017, the transfers from HONI exceeded the transfers to HONI.

b) The WMP data is adjusted for losses.

3-VECC-21
Interrogatory:

Reference: Exhibit 3, page 9

Preamble: The. Application states:

"*A COVID 19 "flag" has also been used as an input variable for the regression model. This variable is used to capture the lower usage for FHI's commercial and industrial customers during March, April, and May of 2020*."

a) Please explain the basis for setting the COVID 19 "flag" at 1.0 for just the months of March, April and May 2020.

b) Were any other COVID-based variable tested (e.g. variables that included more months)? If so what alternatives were tested and why were they rejected?

Response:

a) FHI observed a significant decrease in purchases from March-May 2020.

b) Yes, see 3-Staff-16.

3-VECC-22
Interrogatory:

Reference: Exhibit 3, pages 5 and 10

Preamble: The Application states (page 5):

"*The updated regression analysis removed Full Time Employment as an independent variable from the regression model, as the regional employment independent variable was not statistically significant*."

a) Were any other economic or demographic (e.g. customer count) variables tested? If so, what other variables were tested and why were they rejected?

b) If not tested, please provide a version of the Purchased Power model that also includes monthly customer count (Residential, GS<50, GS>50, Large Use and WMP) as an independent variable. Along with the model, please provide the regression statistics, the 2025 projected purchases and the resulting customer class results for 2025.

Response:

a) FHI tested a customer count variable and an employment rate variable. For the employment rate variable, see 3-SEC-23. For the customer count variable, *FHI included Residential, GS<50, GS>50, and Large Used. FHI rejected the regression analysis with the customer count variable because it did not result in a significant T Stat amount. Results are included below:*

Statistic	Value
R Square	82%
Adjusted R Square	80%
F Test	54.8
MAPE (monthly)	2.0%
T-stats by Coefficient Intercept	1.4
Heating Degree Days	8.9
Cooling Degree Days	10.1
Number of Days in Month	4.4
Spring/Fall Flag	- 2.1
Customer Count	- 1.2
Number of Work Days in Month	4.2
COVID 19 Flag	- 9.8
Strat-Bruce Employment (000's)	1.8

b) *N/A.*

3-VECC-23
Interrogatory:

Reference: Exhibit 3, page 12, Figure 3-1 and Table 3-6

a) Can FHI explain the large variance between actual and predicted purchases in the years 2017 and 2021?

Response:

a) *A large proportion of FHI's consumption is driven by the GS 50 to 4,999 kW and Large Use rate classes. The drivers of these rate classes are not easily explained by external factors, thus, making it difficult for FHI to predict purchases. This is reflected in the relatively lower R Square value of 80%.*

3-VECC-24
Interrogatory:

Reference: Exhibit 3, page 15

a) Please provide the actual customer/connection count for each customer class as of June 30, 2024. If not available, please provide the actual customer/connection count for the most recent month available.

Response:

a) *See 3-SEC-22.*

3-VECC-25
Interrogatory:

Reference: Exhibit 3, page 18, Table 3-16
Load Forecast Model, Rate Class Load Model Tab

The customer class values set out in Table 3-16 for the "Ratios Used in the kW Forecasts" don't match those in the Rate Class Load Model Tab. Please reconcile.

Response:

a) *See 3-SEC-24.*

3-VECC-26
Interrogatory:

Reference: Exhibit 3, pages 10 & 19

a) Please provide a schedule that sets out:
   i. The monthly purchases for 2024 for those months where actual values are available. The values should be comparable to those used in the Load Forecast Model, i.e., include adjusted for the WMPs and Embedded Generation.
   ii. The predicted monthly purchases for the same months, using the Purchased Power model and the actual 2024 values for the independent variables.

Response:

a)
   i. See Table below:

Year	Month	IESO kWh	Embedded Generation kWh	LTLT kWh	Wholesale Market Participant kWh	Total Wholesale Purchases kWh
2024	January	55,966,941	50,267		249,054	56,266,262
2024	February	50,587,451	174,238		227,315	50,989,004
2024	March	51,088,151	260,656		242,896	51,591,703
2024	April	48,121,146	347,161		238,824	48,707,132
2024	May	49,506,834	360,362		260,972	50,128,168
2024	June	51,604,767	389,986		274,155	52,268,908

ii. See table below

Year	Predicted Purchases
2014	620,928,910
2015	620,826,501
2016	626,187,871
2017	618,269,421
2018	628,538,440
2019	623,172,328
2020	601,461,207
2021	624,592,745
2022	621,889,885
2023	613,090,396
2024	620,832,976
2025	619,344,441

EXHIBIT 4 – OPERATING EXPENSES

4-VECC-27
Interrogatory:

Reference: Exhibit 4, page 20

"*2016 - $152,977 – Contract labour increased in 2016 due to this being the first year that IT services were outsourced to FHSI*."

a) What was the offsetting benefit of external contracting IT that made it economical to increase contracted labour costs payable to FHI's affiliate?

b) Please provide the business case that supported the outsourcing of IT costs and was reviewed/approved by FHI management

Response:

a) External IT contracting with FHI's affiliate has provided the ability to add the redundancy, diversified skillsets and capabilities needed to meet FHI's IT needs. Being able to resource appropriately to address increased digital operations as well as requirements such as the OEB cyber security framework allowed FHI to reduce reliance on one or two individuals while delivering greater value than other external consultants.

b) The business case for outsourcing IT costs was handled through the regular FHI budgeting process. As initiatives to modernize FHI's IT infrastructure and address cybersecurity requirements increased in the past 5 years, utilizing the skillset and capabilities within FHI's affiliate company provided the required cost-effective resources while maintaining intimate knowledge of FHI's systems and people. This strategy increases in-house ability to manage day to day and project work and decreases risk through cross-training and reducing reliance on one or two individuals.

4-VECC-28
Interrogatory:

Reference: Exhibit 4,

a) Please provide a listing of the incremental cyber security costs since 2025 noting which are annual and which are one-time costs.

Response:

a) Below is the breakdown of incremental cyber security costs since 2015. These projects have been delivered based on both OEB and cyber insurance requirements and guidelines.

Solution	***One Time Cost***	***Annual Cost***
Next generation firewalls	*$12,495*	*$10,500*
Vulnerability management	*$18,500*	*$5,350*
Device lock-down protection		*$6,800*
Enhanced EDR	*$10,000*	*$7,500*
Security Incident & Event Management (SIEM) + 3rd party security monitoring		*$39,300*
3rd party support – policy development, testing, training	*$65,000*	*$25,000*
Privileged access management	*$28,000*	*$5,000*
Cybersecurity solution for AS400		*$10,000*
Cybersecurity awareness training and phishing simulation system		*$5,400*
Cybersecurity support services		*$118,000*
Total	*$133,995*	*$232,850*

This list does not include expanded initiatives related to information protection/privacy.

4-VECC-29
Interrogatory:

Reference: Exhibit 4, pages 53-

Appendix 2-M

	Regulatory Cost Category	**USoA Account**
	(A)	(B)
	Regulatory Costs (Ongoing)	
	OEB Annual Assessment	5655
	OEB Section 30 Costs (OEB-initiated)	5655
	Expert Witness costs for regulatory matters	
	Legal costs for regulatory matters	
	Consultants' costs for regulatory matters	5630
	Operating expenses associated with staff resources allocated to regulatory matters	5615
	Operating expenses associated with other resources allocated to regulatory matters [1]	5655
	Other regulatory agency fees or	5655

		assessments	
		Any other costs for regulatory matters (please define)	5610
		Intervenor costs	5655

a) FHI appears to have created an Appendix 2-M with only one time application costs. Above is shown a typical Appendix 2-M by category filing. Please fill out this table including the following columns:
   i. Last Rebasing (year)
   ii. Sum of Historical Years (date-to-date)
   iii. 2024 Bridge Year
   iv. 2025 Test Year.

b) It is unclear why the Application -Related one-time costs of $500k are the sum of the 2024 Bridge Costs and the sum of historical years costs 2016-2023 costs. Please explain and describe these historical costs being ascribed to the one-time application costs.

Response:

a) *As stated in the OEB's letter received on April 11, 2024 'Filing Requirements for Electricity Distribution Rate Applications for 2025 Rates', under Models it is noted, "The OEB has also updated Appendix 2-M of the Chapter 2 Appendices. The OEB will no longer require distributors to file on-going regulatory costs in Appendix 2-M. The focus of Appendix 2-M will therefore be the incremental one-time regulatory costs associated with the application." FHI used the OEB template and did not create its own Appendix 2-M.*

b) *Costs related to this Application including consultant and minimal legal costs began in 2023 as the preparation of the Application began. There were no one time costs included that do not relate to this Application.*

4-VECC-30

Interrogatory:

Reference: Exhibit 4, page, 52, 2.4.3.3

a) Please provide a list of all utility memberships (e.g. EDA, CHEC Group, USF etc.) and the associated annual membership fees for the years 2015 through 2025 (forecast).

Response:

a) *See chart below.*

Association	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EDA	42,339	47,800	48,800	49,800	50,800	51,800	52,300	52,300	54,900	56,300	59,900
USF	8,750	8,750	8,750	8,750	8,750	7,950	8,750	8,750	9,000	9,405	9,405
	51,089	56,550	57,550	58,550	59,550	59,750	61,050	61,050	63,900	65,705	69,305

FHI has several other smaller membership that are less than $1.5K such as AEUSP (Association of Electrical Utility Safety Professionals), OnMAG (Ontario Mutual Assistance Group) and PHBA (Perth Huron Builders Association)

4-VECC-31
Interrogatory:

Reference: Exhibit 4, pages

Benefits	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Statutory					
CPP	123,838	133,930	154,204	161,427	166,988
EI Employer Portion	44,208	46,739	52,704	50,977	51,069
EHT	72,724	74,430	79,946	87,823	92,091
WSIB	22,982	10,515	27,052	35,579	37,309
Total Statutory	**263,752**	**265,614**	**313,906**	**335,806**	**347,457**
Company					
OMERS	353,752	365,116	404,465	511,325	545,359
Health	158,447	175,100	213,061	276,979	318,526
LTD	38,963	46,492	49,256	64,032	73,637
Dental	64,567	68,532	72,773	94,605	108,795
Life Insurance	62,747	63,556	62,224	80,891	93,024
Total Company	**678,476**	**718,796**	**801,779**	**1,027,832**	**1,139,341**
Benefits Prior to EFB	942,228	984,409	1,115,684	1,363,638	1,486,800
Employee Future Benefits	(4,252)	(228,047)	127,151	117,642	122,936
Total Benefit Costs	**937,976**	**756,362**	**1,242,835**	**1,481,280**	**1,609,736**

a) Total benefit costs nearly doubled as between 2022 and what is forecast to be incurred in the 2025 Test Year. What amount of this increase is attributable to the increase in the associated year's FTE (41 as compared to 45)? What are the other main drivers of this cost increase?

Response:

a) *The estimated cost for the increase in FTEs is $101K (excluding employee future benefits). The remaining amount is $401K.*

The $401K is due to increases in individual benefit amounts. See the 'per employee' increase for each component of benefits. For some increases are due to increases in wages (such as OMERs) and others are based on the cost of benefits (such as health and dental).

CPP	16%
EI	2%
EHT	15%
WSIB	231%
OMERS	39%
Health	70%
LTD	48%
Dental	48%
Life Insurance	36%

4-VECC-32
Interrogatory:

Reference: Exhibit 4, pages

Corporate Cost Allocation
- 2025

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FHI	*City of Stratford*	Street Light Maint	Cost	100%	$163,123
FHI	City of Stratford	Water/Sewage Bill	Cost	100%	$539,532
FHI	City of Stratford	Building Rent	Market	100%	$38,339

Corporate Cost Allocation
- 2023

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FHI	*City of Stratford*	Street Light Maint	Cost	100%	$149,367
FHI	City of Stratford	Water/Sewage Bill	Cost	100%	$549,376
FHI	City of Stratford	Building Rent	Market	100%	$36,851

a) Why have the revenues for Water/Billing services provided to the City of Stratford declined almost 2% from 2023 to 2025 whereas FHI own billing costs have increased by over 32% (from $708,003 to $938,614 -Appendix 2-JD) over that same period?

Response:

a) *See 4-EP-6 as Water Billing revenue has been updated in 2-H.*

4-VECC-33
Interrogatory:

Reference: Exhibit 4, pages 20 & 29

"*An internal compensation review for non-union staff and an external compensation review for executive staff were completed and the impacts were incorporated into the budget. FHI also projected similar increases levels to benefits as it had seen in 2022 and 2023*."

An Executive Compensation review was completed in 2023 for 2024. These results were built into 2025 estimates.

a) Please provide the above noted compensation review (redacting any personal information).

Response:

a) Please see 4-Staff-20 and 4-Staff-21.

4-VECC-34
Interrogatory:

Reference: Exhibit 4, pages 12-

Metering: In 2015 FHI had nearly zero contracted meter reads for non-communicating meters, by 2025 this cost is approximately $30K/year. FHI also had internal metering staff that is now contracted out solely to ERTH

FHI previously had an in-house IT FTE to assist with the CIS and billing, but this work has been moved to FHSI. There has also been a substantial amount of third-party work required for regulatory upgrades to the CIS

a) How many employees (or FTEs) were reduced due to the contracting out of IT functions?

Response:

a) One.

4-VECC-35
Interrogatory:

Reference: Exhibit 4, page 27

"*Customer Service, Billing, Collecting and Software - $514,471 – Labour has increased in this area due to a new billing position added in 2025 as well as ten years* *of step and inflationary increases totaling $170K. Contract labour has increased by $170K for the outsourcing of bill print, meter data management and settlement."*

a) Please provide the business case that was used to justify the contracting out of bill print, meter data management and settlement.

b) How many FTE were reduced in making this change?

Response:

a)

1) The inserting machine that FHI presently owns was purchased in 2014 and is beyond end of life, with parts no longer available as of 2023. A quote for a replacement inserting machine was obtained totaling $38,725. This did not include the required software needed to print bar codes onto bills for sending specific inserts to specific customers, and this carries a licensing and maintenance contract of $9K/year.

2) Consideration was also given to the time spent by the Billing Coordinator to run this machine, as well as the space that is required in the building for this machine (machine itself sits on about 2' x 7' and then a separate area for mail preparation, sorting and printer is also required), and ensuring an appropriate environment to contain the noise such a machine produces. This area was repurposed as part of the building renovation and there is no longer a space for a bill print area.

3) Additionally, the current bill printer was requiring replacement (estimated cost $13K) and would need additional configuration to print bills in the new format, and climate-controlled space is required to store both envelopes and billing shells, which ceased to be offered by FHI's previous paper and envelopes vendors in 2021.

Meter Data Management and a portion of Settlement is being brought back in-house in the transition to the new CIS in July 2024. Utilismart is still being used for MV90 data for certain commercial customers (both consumption and demand), ICI Program data analysis, and GS>50 customer interface.

b) *No FTEs were reduced with outsourcing of bill print. All aspects of billing, aside from print and mail is still completed in house by the Billing Coordinator.*

4-VECC-36

Interrogatory:

Reference: Exhibit 4, pages 33-

a) Please provide a table showing: (i) all job position/classifications, (ii) number of FTEs (headcount) in that position and, (iii) position salary range for the years 2015, 2023 and 2024. Please note if the calculations are done on a year end-or year average basis. For each job classification please also indicate if the position is subject to incentive pay.

Response:

a) *2023 Mearie Salary Survey has been included in Attachment 3. FHI has also included the 2017 Mearie Salary Survey in Attachment 14 in order to provide an estimate of ranges for 2015 as it does not have access to the 2015 survey.*

# Positions	Incentive	2015
3	No	In or below 2017 Mearie Salary Survey
9	No	In or below 2017 Mearie Salary Survey
16	No	In or below 2017 Mearie Salary Survey / Comparable LDC Union Agreements
15	No	As per public Collective Agreement

# Positions	Incentive	2023
4	Yes	Within ranges noted in Mearie Salary Survey
8	No	Within ranges noted in Mearie Salary Survey
18	No	Within ranges noted in Mearie Salary Survey / Comparable LDC Union Agreements
14	No	As per public Collective Agreement

# Positions	Incentive	2024
4	Yes	Comparable external data for 2024 (Mearie) is not available at this time to provide ranges
8	No	Comparable external data for 2024 (Mearie) is not available at this time to provide ranges
18	No	Comparable external data for 2024 (Mearie) is not available at this time to provide ranges / Comparable LDC Union Agreements for 2024 can be used to estimate ranges
14	No	As per public Collective Agreement

4-VECC-37

Interrogatory:

Reference: Exhibit 4, Appendix 2-JD

a) Account 5315 – Customer Billing has increase significantly as between 2021 ($671k) and forecast 2025 (938k). Please explain why.

Response:

a) *This variance includes new or increased costs:*
External IT consulting costs - $55K
Cyber security - $40K
IBM Server support - $20K
CIS Hosting - $60K
ERP increases to subscriptions/support - $92K

4-VECC-38
Interrogatory:

Reference: Exhibit 4, Appendix 2-JD

a) Notwithstanding a significant increase in overhead renewal capital spending in 2025, OM&A maintenance of overhead plant has significantly increased since 2023. Please explain why if more overhead is being replaced than in the past there is still an increase in maintenance cost of the remaining that plant.

b) Please describe how the forecast amount of $1,133,279 for 2025 overhead services (account 5130) was derived.

Response:

a) *In 2023, FHI, when updating their Activity Performance Benchmarking metrics for the OEB, discovered that USoA 5130 was abnormally high compared to peers in the industry. This led FHI to investigate further, and FHI has since realized that their USoA 5130 has certain costs that other LDC's likely do not. As explained in 1-Staff-1, FHI plans to investigate and re-align these accounts to be closer to typical industry practice, however that is not expected to be completed until 2025.*

   Based on the work that meets the definition of USoA 5130. FHI's costs remain level from 2023 into 2025. Going from actuals of $168,030 in 2023, to a budgeted cost of $168,050 in 2025.

   FHI is not forecasting a significant increase in capital spend on overhead plant and an increase in maintenance costs of overhead plant.

b) *The forecast amount for 5130 was derived by looking at historical labour, material and contracting costs and forecasting those forward based on recent trends, and inflationary increases.*

   It was also derived by looking at upcoming contracts or services that need to be renewed (e.g. fleet services) and estimating this cost increase.

There was also planning and budget set aside to account for replacement staff that are planned to be hired for expected retirements, and the training requirements that accompany new hires.

Finally, an additional FTE that was hired in 2024 to assist in managing FHI's facilities, fleet and buildings has been accounted for in 2025 budgeting for their time.

4-VECC-39
Interrogatory:

Reference: Exhibit 4, Appendix 2-JD

a) Please provide FHI vehicle maintenance expense for each year 2015 through 2025 forecast. Are these amounts subsumed in Account 5675 – Maintenance of General Plant? If not, please explain under what USoA account shown in Appendix 2-JD these costs are captured.

Response:

a) *Please see below for FHI's vehicle maintenance expenses from 2015 through 2025. Please note that 2024 and 2025 are both forecasted numbers based on budget.*

Currently these amounts are subsumed in Account 5130.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Vehicle Maint. Expense ($'000s)	230.40	247.60	282.50	293.30	322.30	226.30	314.70	338	341.50	382.10	419.80

4-VECC-40
Interrogatory:

Reference: Exhibit 4, Appendix 2-JD

a) Please provide a list of the "Outside Services Employed in each year 2022, 2023 and 204 and 2025 forecast.

Response:

a) *See chart below.*

	2022	2023	2024	2025
Property Monitoring and Maintenance	79,751	48,835	85,000	90,500
Audit, Tax and Legal Services	42,997	113,523	76,500	89,075
Corporate Services	33,418	34,709	20,500	41,525
	156,166	197,067	182,000	221,100

*included in corporate services are customer and public survey costs, Mearie survey, actuarial costs etc.

EXHIBIT 5 – COST OF CAPITAL AND CAPITAL STRUCTURE

5-VECC-41
Interrogatory:

Reference: Exhibit 5, page 11

"*FHI is requesting that the notional debt attract the weighted average cost of actual Long-Term Debt rather than the current deemed long-term debt rate issued by the Board. FHI is actively moving closer to the deemed 60/40 split to ensure FHI receives the benefit of lower debt rates while still retaining flexibility and debt capacity for future capital needs. For example, the actual split proposed in 2025 is 54/46 debt to equity which has increased from 2022, which was 50.5/49.5 debt to equity*."

a) FHI's long-term debt capital structure has historically, and continues, to be significantly underleveraged (comparing actual debt to Board deemed structure). FHI only achieves approximately 75% of its deemed long-term debt allowance for the purpose of calculating rates. Please explain why the Utility does not more closely finance in line with its deemed capital structure.

b) Please explain how FHI diversifies it long-term debt portfolio?

c) FHI states it expects to now increase its actual long-term debt structure in 2025. During the past two years the cost of debt has significantly increased as evidenced by FHI own estimates of the cost of future long-term debt. Please explain why a strategy of proportionally increasing its long-term debt during periods of high debt costs (as opposed to the prior periods of lower costs) constitutes prudent financial planning.

d) Given FHI's practice of underleveraging during periods of low-cost debt why is it reasonable to price 2025 notional long-term debt at the higher amount of 4.75% based on its actual and forecast 2025 long-term debt rather than the lower amount of 4.58% based on the Board last published deemed long-term debt rate?

Response:

a) *In the past FHI did not use external debt to finance its ongoing capital plan and instead only obtained debt financing for larger one-time capital expenses such as Smart Meters and the Transformer Station. FHI is slowly transitioning, as noted, to ongoing or more frequent capital financing, while ensuring the management of financing costs and attempting to take advantage of lower debt rates.*

b) *FHI uses both fixed term loans and swap loans depending on the most advantageous products at the time when debt is being pursued. FHI also considers the number of years of repayment and staggers execution dates to diversify its debt. FHI monitors external market information and rates weekly to determine trends in rates.*

c) *Swap loan #2 was a 3-year forward fix loan that was contracted in 2021 to take advantage of the low rates at that time, which was extremely prudent. It was estimated that debt would be required at the latest by the end of 2024. FHI drew on a portion of this debt in 2023 and will not realize the benefit of the forward fix rate until December 31, 2024. FHI did not request more than $5M at that time as it did not want to take on more debt than it needed. At that time, FHI did not plan to replace CIS and ERP. 2025 proposed debt, while higher than the rate achieved in 2021, is still significantly cheaper than the cost of equity.*

d) *Notional debt was calculated based on current market conditions and the cost to increase debt over the rebasing period will likely be higher than 4.75% even as rates decrease in future years.*

5-VECC-42
Interrogatory:

Reference: Exhibit 5, pages 5-6

a) Please provide the basis for the forecast cost of 6.06% for the loan expected to be issued on January 1, 2025. Specifically, please show how this estimate relates to current corporate long-term bond yields or other market indicators of future long-term debt rates.

b) What due diligence has FHI undertaken to ensure its preferred lender is offering a competitive rate?

c) Given the current high interest environment why is it prudent to finance through 25-year loans rather than shorter period (e.g. 5-20 years) in order to diversify its interest rate risk?

Response:

a) *As received by RBC on February 16, 2024, “Indicatively, as at today, had we booked a forward fix CORRA/SWAP loan for $10,000,000 for advance Jan 2nd, 2025, with a 10-year SWAP and a 10-year CORRA term with repayment over 10 years, the all-in rate would have been 6.05%.” Based on current market rates published for June 2024, yields are estimated at 3.5-4.75% which would not include a bank stamping fee, which based on FHI’s last agreement was 1.81%.*

b) *As noted, FHI monitors rate trends weekly. FHI benefits from a long-term financial and risk relationship with RBC including lower costs on monthly transactions and services to finance with RBC, however rates are often compared to competitors, specifically when new debt is being reviewed. The swap component of the loan is the same regardless of the bank. The stamping fee component is competitive and FHI requests that RBC provides information on the competitiveness of this rate.*

c) *2-OB was corrected as part of the IR process, the 2024 and 2025 Swap loans are 10 years.*

5-VECC-43
Interrogatory:

Reference: Exhibit 5, Appendix 2-OB

a) Please recalculate the weighted cost of long-term debt (i.e. Appendix 2-OB) substituting the cost of both notional debt and the New Loan (i.e. line 5) at an interest rate of 4.58%. Please also provide the revenue requirement impact of making this change.

Response:

a) *See recalculated weighted cost of long-term debt and revenue requirement impact below:*

2025 Weighted Cost of Long-Term Debt (Appendix 2-OB)

Year 2025

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Shareholder Loan	City of Stratford	Affiliated	Fixed Rate	1-Nov-00	Demand	$15,600,000	0.0458	$ 714,480.00	
2	Bank Loan	RBC	Third-Party	Fixed Rate	4-Nov-21	4	$ 107,715	0.0262	$ 2,822.13	
3	Swap Loan #1	RBC	Third-Party	Fixed Rate	31-May-13	25	$ 8,601,500	0.0474	$ 407,711.10	
4	Swap Loan #2	RBC	Third-Party	Fixed Rate	31-Dec-24	10	$ 4,813,816	0.0402	$ 193,515.40	
5	New Loan	RBC	Third-Party	Fixed Rate	1-Jan-25	10	$ 4,875,800	0.0458	$ 223,311.64	
Total							$33,998,831	4.53%	$1,541,840.28	

Revenue Requirement Computation

Application Summary	2025 Test	2025 Test	Variance
Weighted Debt Cost Rate	4.75%	4.53%	-0.22%
Average Net Fixed Assets	64,668,717	64,668,717	-
Working Capital Allowance	5,699,781	5,699,781	-
Rate Base	**70,368,497**	**70,368,497**	**-**
Working Capital Allowance	7.50%	7.50%	0.00%
Regulated Return on Capital	4,637,878	4,554,804	- 83,074
OM&A including Property Taxes	9,430,261	9,430,261	-
Amortization Expense	3,114,180	3,114,180	-
PILs	304,086	304,086	-
Service Revenue Requirement	**17,486,405**	**17,403,331**	**- 83,074**
Less: Revenue Offsets	1,197,894	1,197,894	-
Base Revenue Requirement	**16,288,511**	**16,205,437**	**- 83,074**

5-VECC-44

<u>Interrogatory:</u>

Reference: Exhibit 1, Attachment 1-11 – FHI Business Plan, page 15

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%

a) Please revise the above table to include the years 2015 through 2017 and 2023.

<u>Response:</u>

a) See chart below.

Indicator	2015	2016	2017	2023
Liquidity: Current Ratio	0.46	0.55	0.50	0.53
Leverage: Total Debt to Equity Ratio	1.26	1.32	1.32	0.99
Regulatory ROE: Deemed	9.30%	9.30%	9.30%	9.30%
Regulatory ROE: Achieved	14.24%	7.37%	8.43%	8.62%

EXHIBIT 6 – REVENUE REQUIREMENT AND REVENUE DEFICIENCY OF SUFFICIENCY

6-VECC-45
Interrogatory:

Reference: Chapter 2 Appendices, Appendix 2-H
Exhibit 6, page 22

a) With respect to Account #4210, please provide the details supporting the 2023, 2024 and 2025 Joint Pole Use revenues (i.e. number of poles and annual rate).

b) Please explain why there are no actual or forecast values for Account #4405 (Interest and Dividend Income).

c) Please provide the basis for the 2023 and 2024 forecast values for the following Accounts:
   i. #4220
   ii. #4225
   iii. #4235
   iv. #4315

Response:

a) *See chart below.*

	2023	2024	2025
# of Poles	4,363	4,314	4,314
Rate	22.35	22.35	37.78
Joint Pole Attachment Revenue	97,513	96,418	162,983
Originally included 2025 at 22.35 in budget			83,288
Correction required to 2-H			79,695

b) *4405 includes interest revenue from DVAs. In the past it earned funds on its bank balance and intercompany loan however the bank balance is in a bank indebtedness position and the intercompany is also in a payable position in 2025.*

c) *i. #4220 – 2023 is yearend actual. 2024 has been updated based on 2024 projections (76% of prior year) which have materially changed since the budget was created. See changes in 2-H.*

ii. #4225 – 2023 is yearend actual. 2024 took the average of the past 3 years and increased by 1%. Actuals to June 30 for 2024 are trending to align with estimate.

iii. #4235 – 2023 is yearend actual. 2024 used 2023 projection at the time of budget preparation with the exception of Account Set Up/Change of Occupancy Fees and NSF Fees which have been consistently decreasing by $5K per year, this trend was incorporated into 2024 budget. Actuals to June 30 for 2024 are trending to align with estimate. However, 4235 is being amended in 2-H to account for 6-SEC-34 IR.

iv. #4315 – 2023 is yearend actual. 2024 used 2023 projection at the time of budget preparation plus added an inflationary increase for property taxes billed. Actuals to June 30 for 2024 are trending to align with estimate.

A summary of 2025 2-H changes have been included below:

USoA	Other Revenue	2025 Test	2025 Updated Test	Variance	Explanation
4082	RS Rev	27,259	29,413	2,154	Updated for revised RTSR Rates as requested in 8.0-VECC-51
4210	Rent from Electric Property	128,633	208,328	79,695	Update based on Joint Pole Rates identified in 6.0-VECC-45
4220	Other Electric Revenues	181,697	121,075	- 60,622	Update based on material variance in projections for 2024 and 2025 since original budget prepared
4235-1	Miscellaneous Service Revenues	70,801	83,425	12,624	Update based on Specific Service Charges identified in 6-SEC-34
4375	Revenues from Non-Utility Operations	947,880	976,429	28,549	Update based on Shared Service adjustments identified in 4-EP-6, also adjusted in 2-N.
4390	Miscellaneous Non-Operating Income	52,982	22,145	- 30,837	Update based on material variance in projections for 2024 and 2025 since original budget prepared
Total Adjustments				**31,562**	
			Original 2-H	1,166,332	
			Revised 2-H	1,197,894	

* 4220 and 4390 were updated based on material changes to 2024 actuals, the remainder of accounts are trending in line with budgets.

EXHIBIT 7 – COST ALLOCATION

7-VECC-46
Interrogatory:

Reference: Cost Allocation Model, Tab 7.1
Exhibit 3, page 7

a) Please explain why the number of meters used for the Residential, GS and GS.50 classes in Tab 7.1 (Meter Capital) don't match the 2025 forecast number of customers per Exhibit 7 for these classes.

b) Do any of the customers actually have more than one meter?
   a. If so, how many additional FHI owned meters are installed for each customer class?

Response:

a) See 7-Staff-38.

b) No, see 7-Staff-38.

7-VECC-47
Interrogatory:

Reference: Exhibit 7, pages 6-7
FHI's Conditions of Service, Sections 2.1.1.1 and 2.1.1.2

a) It is noted that FHI's Conditions of Service only addresses the payment of connection/services costs for the Residential and GS classes. Where is the responsibility for connection/services for the Sentinel, USL, Street Lighting and Large Use classes documented?

Response:

a) In Section 3.8 "Unmetered Connections" of FHI's Conditions of Service, reference is made to costs that Sentinel, USL and streetlighting connections are responsible for. Specifically, the first sentence states that "Unmetered connections are treated as General Service less than 50kW rate class accounts." Meaning that FHI treats the cost responsibilities the same as these customers.

In Section 3.4 "Large User General Service (Greater than 5000kW)" FHI uses the term General Service in the section heading to indicate that Section 2.1.1.2 "Connection Charges – General Service Class Customers" is the applicable section to reference for connection charges.

7-VECC-48
Interrogatory:

Reference: Exhibit 7, pages 7 – 8

Preamble: The Application states (page 7):

"*In determining the weighting factors for Billing and Collecting, an analysis of Accounts 5315 – 5340, except 5335, was conducted and costs were assigned to each class based on the specific nature of the costs*."

a) Please provide a copy of the analysis deriving the Billing and Collecting weighting factors.

b) If not clear from this analysis, please explain why the Billing and Collecting weighting factor for the Large Use class is less than that for the GS>50 class.

Response:

a) See 7-Staff-31.

b) N/A.

7-VECC-49
Interrogatory:

Reference: Exhibit 7, pages 9 - 10

a) Are the costs associated with maintaining/updating the records regarding the kWh and kW use per device/connection for the Street Lighting, Sentinel and USL classes tracked and allocated to the respective classes?
   i. If yes, in what account(s) are they tracked and where is the allocation done in the CA Model?
   ii. If not, in what account(s) are they tracked and how are they subsequently allocated to customer classes?

Response:

a)
   i. FHI tracks the costs in 5315. This account is included in the weighting factors for Billing and Collecting.

   ii. N/A.

EXHIBIT 8 – RATE DESIGN

8-VECC-50
Interrogatory:

Reference: Exhibit 8, page 8 /Load Forecast Model, Rate Class Load Model Tab / RTSR Workform, RRR Data Tab

Preamble: The Application states:

"*FHI has two > 50kW customers that will be charged on a gross load billing basis from Hydro One for wholesale transmission services due to load displacement generation greater or equal to 1 MW with non-renewable generation and/or equal to or greater than 2 MW for renewable generation (wind, solar, biomass, bio-15 oil, bio-gas, landfill gas, or water). As a result, FHI proposes to charge the RTSR to these customers on a gross load basis. FHI has amended the RTSR for gross load billing for these two customers*."

a) Please confirm that the RRR data used in the RTSR Workform is based on 2023.

b) Please explain why the 2023 kW values for the Large Use, Sentinel and Street Lighting classes used in the RTSR Workform don't match the 2023 kW values as set out in the Load Forecast Model for these classes.

c) Exhibit 8 states that the billing kW used in the RTSR Workform has been gross-up to account for the fact for two > 50kW customers FHI will be charged on a gross load billing basis from Hydro One for wholesale transmission services. However, the GS>50 kW value used in the RTSR is 886,551 kW which is less than the sum of the 2023 GS>50 and WMP billing kW (880,547+17,350=897,897 kW) set out in the Load Forecast Model. Please reconcile.

d) For the two GS>50 customers with embedded generation, is the generation metered separately?
   i. If yes, does FHI own the meters?
   ii. If yes, does FHI read the meters?

e) With respect to the RTSR Workform, please confirm that the billing units in Tab 5 are based on the same year as the customer class usage data in Tab 3

Response:

a) Confirmed.

b) *The kW values for the Large Use, Sentinel and Street Lighting classes used in Tab 3 of the RTSR Workform matches the kW values set out in the Load Forecast model for these classes and no explanation is required.*

c) *FHI has not amended the RTSR for gross load billing as the RTSR is based on 2023 data. The RTSR value used in the RTSR model matches the sum of the 2023 GS> 50 and WMP billing kW (876,527 + 10,024= 886,551 kW) It appears this question is comparing 2023 RTSR data to 2025 Load Forecast data rather than 2023 in both models.*

d) *Yes, both of these installations have the generation metered separately.*
   i. *Yes, FHI owns the meters.*
   ii. *Yes, FHI is able to read the meters and has them in our Settlement System (Utilismart).*

e) *Confirmed.*

8-VECC-51
Interrogatory:

Reference: Exhibit 8, pages 9 - 10

Preamble: The Application states:

"*The report stated that the rates are subject to an adjustment mechanism using the annual adjustment factor applied in the OEB's incentive regulation mechanism. For the purposes of this Application, FHI is using the proposed inflation factor of 4.8% on 2024 charges as outlined in Attachment 8-3 as per FHI_2025_Tariff_Schedule_and_Bill_Impact_Model_20240426 live Excel in Tab 3 Regulatory Charges. Table 8-9 below provides the Proposed Charges for Retail Service charges in its 2025 Test Year budget*." (page 9)

And

"*The increase in Retail Service Charges due to inflation has been included in projections for Other Revenue*." (page 10)

a) Please update the proposed 2025 Retail Service Charges to reflect the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024.

b) Does this update impact FHI's forecast Other Revenues for 2025? If yes, please provide an updated version of Appendix 2-H.

Response:

a) *See the proposed 2025 Retail Service Charges reflecting the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024.*

b) *See table below.*

Retail Service Charge	Current Charge	Inflation Factor	Proposed Charge
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$ 117.02	3.6%	$ 121.23
Monthly fixed charge, per retailer	$ 46.81	3.6%	$ 48.50
Monthly variable charge, per customer, per retailer	$ 1.16	3.6%	$ 1.20
Distributor-consolidated billing monthly charge, per customer, per retailer	$ 0.69	3.6%	$ 0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	-$ 0.69	3.6%	-$ 0.71
Service Transaction Requests (STR)	$ 0.59	3.6%	$ 0.61
Request fee, per request, applied to the requesting party	$ 0.59	3.6%	$ 0.61
Processing fee, per request, applied to the requesting party	$ 1.16	3.6%	$ 1.20
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party up to twice a	No Charge	3.6%	No Charge
More than twice a year, per request (plus incremental delivery costs)	$ 4.68	3.6%	$ 4.85
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the notice of switch charge. Applicable only to letters that are sent by standard hard copy)	$ 2.34	3.6%	$ 2.42

8-VECC-52
Interrogatory:

Reference: Exhibit 8, page 11

Preamble: The Application states:

"*Income Tax Letter – Currently FHI has a $15 Income Tax Letter charge. Based on how this is used in current practice, FHI is requesting that this be called Bill Copy Charge with no change to the amount.*

Service Call – Customer Owned Equipment and Service Call – After Regular Hours – FHI is requesting that the two Service Call charges be changed to be listed as Time & Materials instead of $30 and $165 respectively. In FHI's experience the cost of these effects can vary and each service call is tracked by a separate work order and can be easily billed on time & materials."

a) How is the Income Tax Letter used in "current practice"?

b) Will customers have to pay the Bill Copy Charge of $15 if they request a another/duplicate copy of their monthly bill delivered by mail or e-mail?

c) How many instances of a Service Call-Customer Owned Equipment were there in 2023, what were the causes for such calls and what was the range of actual costs incurred for such a service call?

d) How many instances of a Service Call-After Hours were there in 2023, what were the causes for such calls and what was the range of actual costs incurred for such a service call?

e) Are customers billed for either a Service Call – Customer Owned Equipment and Service Call – After Regular Hours if the issue is a matter of safety?

Response:

a) Please see 8-Staff-42 (b).

b) FHI does not charge a customer to email them a copy of their bill and works hard to ensure all customers know how they can access the last 24 months of bills electronically through its website, regardless of whether they have enrolled in paperless billing.

c) In 2023 FHI recorded 35 instances of these types of service calls. Typical causes of calls were partial or no power, which were determined to be customer equipment issues, or isolations to provide customers the ability to complete their repairs safely.

FHI did not track every single one of these, as under its conditions of Service, FHI will provide disconnect and reconnect during regular hours free of charge to customers.

However, isolations of High voltage equipment have been tracked from $500-$1,200, and anecdotally, for low voltage residential issues, it is typically ½-1 hour of on-site time in addition to travel time, which would range from $60 to $250 depending on location.

d) In 2023 FHI recorded 73 instances of these types of service calls. Typical causes of calls were partial or no power, emergency locates, or disconnect and remove service.

FHI does not have tracking for every single one of these instances, however, based on the data available, the actuals ranged from $175 (minimum call out charge for staff) to $400 for residential issues, and over $1,000 if requiring High Voltage isolation or work for the customer.

e) Historically FHI has never billed either of these charges for safety matters.

8-VECC-53
Interrogatory:

Reference: Exhibit 8, pages 11 - 12

Preamble: The Application states:

"*As part of EB-2023-0194, wireline pole attachments rate has been set at $37.78 effective January 1, 2024. FHI does not have an LDC specific charge and will charge the OEB approved rate to its pole line attachments. FHI will update for 2025 rates when they become available*."

a) Please update the 2025 Specific Charge for Access to The Power Poles in Table 8-10 to reflect the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024.

b) Does this updated rate for the 2025 Specific Charge for Access to The Power Poles impact FHI's forecasted Other Revenue for 2025? If yes, please provide an updated version of Appendix 2-H.

Response:

a) See table with update 2025 Specific Charge for Access to the Power Poles in Table 8-10 to reflect the 3.6% inflation factor for 2025 as published by the OEB on June 20, 2024, below:

Specific Service Charges	Current	Proposed
Customer Administration		
Arrears Certificate	$ 15.00	$ 15.00
Income Tax Letter	$ 15.00	$ -
Bill Copy Charge	$ -	$ 15.00
Credit Reference/Credit Check (Plus Credit Agency Costs)	$ 15.00	$ 15.00
Returned Cheque (Plus Bank Charges)	$ 15.00	$ 15.00
Account Set Up Charge / Change of Occupancy Charge (Plus Credit Agency Costs If Applicable)	$ 30.00	$ 30.00
Meter Dispute Charge Plus Measurement Canada Fees (If Meter Found Correct)	$ 30.00	$ 30.00
Non-Payment of Account		
Late Payment - Per Month (Effective Annual Rate 19.56% Per Annum or 0.04896% Compounded Daily Rate)	$ 0.02	$ 0.02
Reconnection At Meter - During Regular Hours	$ 65.00	$ 65.00
Reconnection At Meter - After Regular Hours	$ 185.00	$ 185.00
Reconnection At Pole - During Regular Hours	$ 185.00	$ 185.00
Reconnection At Pole - After Regular Hours	$ 415.00	$ 415.00
Other		
Service Call - Customer Owned Equipment	$ 30.00	Time & Materials
Service Call- After Regular Hours	$ 165.00	Time & Materials
Temporary Service Install & Remove - Overhead - No Transformer	Time & Materials	Time & Materials
Temporary Service Install & Remove - Underground - No Transformer	Time & Materials	Time & Materials
Temporary Service Install & Remove - Overhead - With Transformer	Time & Materials	Time & Materials
Specific Charge For Access To The Power Poles - $/Pole/Year (With The Exception of Wireless Attachments)	$ 37.78	$ 39.14

b) *See 4-EP-6, 2-H has been updated.*

8-VECC-54
Interrogatory:

Reference: Exhibit 8, page 13

Preamble: The Application states:

"*FHI is proposing to update the LV rate for the 2025 Test Year and has projected 2025 LV costs based on 2023 volumes and applied 2024 rates in the amount of $302,912*".

a) Please provide the derivation of the $302,912.

b) Please confirm that HONI bills its ST Rates charged to FHI on a gross demand for customers with load displacement generation at 1MW or above, or 2MW or above for renewable generation, installed after October 1998.
   i. If confirmed, please indicate whether FHI proposes to bill LV charges to its two GS>50 customers with embedded generation on a gross load basis.

Response:

a) FHI applied 2024 rates to the 2023 volumes. The calculation is provided in Attachment 15.

b)
   i. FHI does not propose to bill LV charges to its two GS 50 to 4,999 kW customers with embedded generation on a gross load basis. FHI will be charged on a gross load billing basis from Hydro One for wholesale transmission services. FHI proposes only to charge the RTSR to these customers on a gross load basis.

8-VECC-55
Interrogatory:

Reference: Exhibit 8, page 15, Table 8-14
Load Forecast Model, Rate Class Energy Model Tab

a) Please reconcile the annual purchases for 2019-2023 as set out in the Rate Class Energy Model Tab (Column B) with the A (1) and A (2) wholesale purchases for the same years set out in Table 8-14.

Response:

a) *FHI excluded Wholesale Market Participant volumes in the Wholesale and Retail volumes in Table 8-14. If Wholesale Market Participant volumes are excluded from the annual purchases for 2019-2023 in the Rate Class Energy Model (Column B), the annual purchases agree to A(1) in Table 8-14*

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9-VECC-56
Interrogatory:

Reference: Exhibit 9, page 13, Table 9-4

a) Please revise Table 9-4 as necessary subsequent to any changes made as a result of responding to interrogatories or other updates and show the amount sought for disposition in this application and the proposed length of the associated rate rider.

Response:

a) *See below.*

Account Descriptions	Account Number	Principal Amounts as of Dec 31, 2023	Carrying Charges to Dec 31, 2023	Principal Disposals Jan 1, 2024 (EB-2023-0021)	Interest Disposals Jan 1, 2024 (EB-2023-0021)	Principal and Interest	Projected Carrying Charges 2024	Total Disposition 2025
Group 1 Accounts								
LV Variance Account	1550	188,664	8,667	92,018	6,445	98,868	5,306	104,174
Smart Metering Entity Charge Variance Account	1551	-106,168	-4,918	-52,124	-3,485	-55,476	-2,967	-58,443
RSVA - Wholesale Market Service Charge	1580	673,320	76,184	1,321,482	87,634	-659,612	-35,584	-695,196
Variance WMS – Sub-account CBR Class B	1580	9,270	-1,992	-37,630	-2,812	47,720	2,575	50,295
RSVA - Retail Transmission Network Charge	1584	987,971	47,746	549,375	38,077	448,266	24,079	472,344
RSVA - Retail Transmission Connection Charge	1586	655,002	24,109	226,196	14,423	438,492	23,541	462,033
RSVA - Power (excluding Global Adjustment)	1588	-4,441	-85,609	684,003	-41,833	-732,220	-23,201	-755,421
RSVA - GA	1589	666,571	52,131	420,147	24,590	273,965	3,068	277,033
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	-	-	-	-	-	0	-
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	1,005	7,262	1,005	7,262	-0	-	-
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	47,565	-27,688	50,781	- 26,842	-4,062	-177	-
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	-66	-5,679	-	-	-5,745	-4	-5,749
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	2,530	13,636	-	-	16,166	139	-
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	28,794	76,979	-	-	105,772	3,992	-
Total for Group 1 Accounts		**3,150,018**	**180,827**	**3,255,253**	**103,459**	**- 27,867**	**767**	**- 148,930**
Group 2 and Other Accounts								
OEB Cost Variance Account	1508	202,826	16,675				63,186	282,687
Wire Pole Attachment Var Acct	1508	-400,126	-30,326				-90,408	-520,860
ULO implementation costs	1508	61,710	847				3,388	65,945
Retail Cost Variance Account - Retail	1518	41,074	4,096				8,203	53,373
Retail Cost Variance Account - STR	1548	-1,008	-110				-163	-1,281
PILs and Tax Variance for 2006 and Subsequent Years - Recover PILs	1592	-370,548	-30,642				-	-401,190
Total for Group 2 and Other Accounts		**- 466,072**	**- 39,460**	**-**	**-**	**-**	**- 15,794**	**- 521,327**
Total Deferral and Variance Account Balances		**2,683,945**	**141,367**	**3,255,253**	**103,459**	**- 27,867**	**- 15,027**	**- 670,257**

All are requested to be a one-year disposal. OPEB DVA removed, OEB Fees and Joint Pole updated. See below for Joint Pole Table update and see 9-VEC-59 for OEB Fees update.

Account Descriptions	Total Billed Wire Attachments	Wire Attachments Recorded in Revenue	Variance
2018	(98,373)	(90,099)	(8,274)
2019	(190,156)	(97,256)	(92,900)
2020	(195,274)	(109,153)	(86,121)
2021	(192,097)	(92,702)	(99,395)
2022	(150,096)	(96,434)	(53,663)
2023	(157,287)	(97,513)	(59,774)
2024 - Estimate	(162,587)	(96,418)	(66,169)
Closing Interest Balances as of Dec 31, 2023 Adjusted for Dispositions During 2024			(30,328)
Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31, 2024 Balance Adjusted For Disposition During 2024			(24,237)
Total Claim - Wire Pole Attachments			**(520,860)**

9-VECC-57
<u>Interrogatory:</u>

Reference: Exhibit 9, page

"*The second variance is in 1592 PILs and Tax Variance – CCA Changes in the amount of $300,519. Similarly to above, the account was corrected after the 2023 financial statements were completed and FHI will adjust in 2024 upon approval of the claim amount in this account*."

a) Please clarify the nature and magnitude of the above described error and correction.

<u>Response:</u>

a) Prior to a detailed review in early 2024, FHI was accruing an estimate annually based on internal guidance in 2018. FHI completed a detailed review with its external corporate tax provider and determined that the amount was understated going back to 2018 and this amount was updated accordingly. The correct amount was calculated and is included in the updated DVA Continuity included in this submission.

9-VECC-58
<u>Interrogatory:</u>

Reference: Exhibit 9, page 19

Table 9-11 OPEB Variance

Account Descriptions	2018	2019	2020	2021	2022	2023	2024	Total
Current service and interest costs	69,618	72,000	76,274	76,354	75,211	71,634	74,858	515,949
Benefits paid	(122,293)	(125,436)	(135,524)	(127,022)	(123,718)	(112,576)	(117,642)	(864,211)
Total Cash method	(52,675)	(53,436)	(59,250)	(50,668)	(48,507)	(40,942)	(42,784)	(348,262)
OPEB costs built into rates from 2015	33,793	34,147	34,677	35,336	36,396	37,524	39,100	250,972
Difference	(18,882)	(19,289)	(24,573)	(15,332)	(12,111)	(3,418)	(3,684)	(97,290)
Closing Interest Balances as Of Dec 31, 2023 Adjusted for Dispositions During 2024*								-
January 1, 2024, to December 31, 2024, on Dec 31, 2024 Balance *								-
Total OPEB Claim								**97,290**

a) Please explain why Table 9-11 does not include the years 2015 through 2017 (i.e. since last rebasing)

b) Please provide the basis/calculation of the "*OPEB costs built into rates from 2015*". Specifically, please explain the relationship between the amounts shown in this row in Table 9-11 and the Amounts shown in Accounts 5645 and 5646 as Shown in Appendix 2-JD.

<u>Response:</u>

a) *Prior to 2018, variances weren't tracked as the variance account was established effective January 1, 2018.*

b) *See response to 9-Staff-48 a).*

9-VECC-59

<u>Interrogatory:</u>

Reference: Exhibit 9, page 14

Table 9-5 1508 OEB Cost Variance

OEB Fees	Included in Rates	Amount Spent	Variance
2016	60,990	69,274	8,284
2017	61,874	93,494	31,620
2018	62,338	87,364	25,026
2019	62,993	88,940	25,947
2020	63,969	89,253	25,284
2021	65,185	86,377	21,192
2022	67,140	95,256	28,116
2023	69,222	106,579	37,357
2024 -- Estimate	72,129	119,237	47,109
Closing Interest Balances as of Dec 31, 2023 Adjusted for Dispositions During 2024			16,675
Projected Interest from Jan 1, 2024, to December 31, 2024, on Dec 31, 2024, Balance Adjusted For Disposition During 2024			12,019
Total Claim - OEB Fees			**278,629**

"*This account was authorized by the OEB in its letter Revisions to the Ontario Energy OEB Cost Assessment Model, dated February 9, 2016. In that letter the OEB established Account 1508 – Other Regulatory Assets Sub-Account OEB Cost Assessment Variance. The purpose of this account is to record differences between the annual OEB cost assessment currently approved in rates and the actual OEB cost assessment amounts charged by the new cost assessment model, effective April 1, 2016*."

a) Please update the above table for two columns showing:
   i. the actual OEB Cost Assessment (net of any Section 30 assessments),
   ii. Typically, a utility with 2015 based rates would be expected to apply for 2020 rates in 2019. annual interest. Please provide any evidence which shows the Board's acceptance that the FHI should continue to book amounts into Cost Assessment account after it sought to defer rebasing.

b) Please explain how the 2024 estimate of OEB assessment costs was calculated.

Response:

a)

i. This only includes the actual quarterly OEB Cost Assessment costs. Section 30 assessments are expensed.

ii. *As stated in the letter "Regulated entities are to cease recording amounts in these accounts when their rates, payment amounts or fees (as applicable) are rebased/reset (cost of service or custom IR) incorporating an updated forecast of cost assessments.*

Carrying charges at the OEB-prescribed rate are to be calculated using simple interest applied to the monthly opening balances in the accounts (exclusive of accumulated interest) and recorded in a separate sub-account.

Regulated entities are expected to seek disposition of the variance account balances when their rates, payment amounts or fees, as applicable, are next rebased/reset, and the accounts will be closed to any further entries at that time."

The letter does not state that amounts should cease to be recorded if the typical rebasing period is not met.

b) *2024 costs were estimated to be one quarter at $27,237 (2023's invoice amount) + three quarters at $30,667 = $119,237. This amount is understated as the three remaining quarters are being billed at $31,993 for a total of $123,216. This amount has been updated in the DVA continuity.*

OEB Fees	Included in Rates	Amount Spent	Variance
16	60,990	69,274	8,284
17	61,874	93,494	31,620
18	62,338	87,364	25,026
19	62,993	88,940	25,947
20	63,969	89,253	25,284
21	65,185	86,377	21,192
22	67,140	95,256	28,116
23	69,222	106,579	37,357
24 - Estimate	72,129	123,216	51,088
Closing Interest Balances as of Dec 31, 2023 Adjusted for Dispositions During 2024			16,675
Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31, 2024 Balance Adjusted For Disposition During 2024			12,098
ıtal Claim - OEB Fees			**282,687**

End of document.

Attachment 1

2-Staff-6 – Festival Hydro 2004 Public Safety Survey

INNOVATIVE RESEARCH GROUP

Survey Results

Public Awareness of Electrical Safety Scorecard

Festival Hydro Inc.

April 2024

STRICTLY CONFIDENTIAL

Key Findings

As required by the Ontario Energy Board (OEB), all Ontario-based LDCs must measure public awareness of electrical safety every two years and submit these results as part of their annual Scorecard. 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 approved 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 (51%) would definitely call before digging.
- **Impact of touching a power line:** Almost all respondents (92%) think touching a power line is "very dangerous".
- **Proximity to overhead power line:** 1-in-5 respondents (22%) believe they should maintain a distance of 3 to 6 metres. Almost half (45%) believe they should maintain a distance of 6 metres or more.
- **Danger of tampering with electrical equipment:** 9-in-10 respondents (88%) believe tampering with equipment is "very dangerous".
- **Proximity to downed power line:** 3-in-4 (74%) believe they should maintain a distance of 10 metres or more.
- **Actions taken in vehicle in contact with wires:** Nearly all respondents (90%) believe they should stay in the vehicle until power has been disconnected from the line.

Festival Hydro has an overall score of 81% on the Public Safety Awareness Index (up slightly from 2022 at 77%).

- **Highest at-risk groups:** Those who are not aware of the type of electricity service at their residence (73% score) and those who reside in a farm or not in a house or condo (72% 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 55+ (83% score) have the highest Safety Awareness Index score. Following behind are those who live in a fully detached house (83% score), Women 35-54 (82%) and Men 35-54 (81%).

2024 Safety Awareness Dashboard

22%

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

92%

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

51% Would ***definitely*** call before digging

Overall Public Safety Awareness Index Score

81%

90%

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

88%

74%

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 2024 *Public Awareness of Electrical Safety Scorecard* survey as required by the Ontario Energy Board (OEB).

- This survey was conducted by telephone among **403** randomly-selected Ontario residents, 18 years or older, currently residing in **Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, or Zurich,** between March 11th and March 28th, 2024.
- 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**.
- 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.*

INNOVATIVE RESEARCH GROUP

Methodology | Previous Tracking

This survey is a tracking survey. The results from this year have been compared to the 2022 and 2016 Public Awareness of Electrical Safety Scorecard survey. Details below:

2024 Public Awareness of Electrical Safety Scorecard survey

Method: Telephone
Field Dates: March 11th – March 28th, 2024
Sample Frame: Ontarian residents, 18 years or older, currently residing in Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, or Zurich
Sample Size: Total sample size n=403, n; weighted proportionately down to n=400.

2022 Public Awareness of Electrical Safety Scorecard survey

Method: Telephone
Field Dates: March 1st – March 11th, 2022
Sample Frame: Ontarian residents, 18 years or older, currently residing in Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, or Zurich
Sample Size: Total sample size n=408, n; weighted proportionately down to n=400.

2020 Public Awareness of Electrical Safety Scorecard survey

Method: Telephone
Field Dates: March 2nd – March 16th, 2020
Sample Frame: Ontarian residents, 18 years or older, currently residing in Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, or Zurich
Sample Size: Total sample size n=403, n; weighted proportionately down to n=400.

2018 Public Awareness of Electrical Safety Scorecard survey

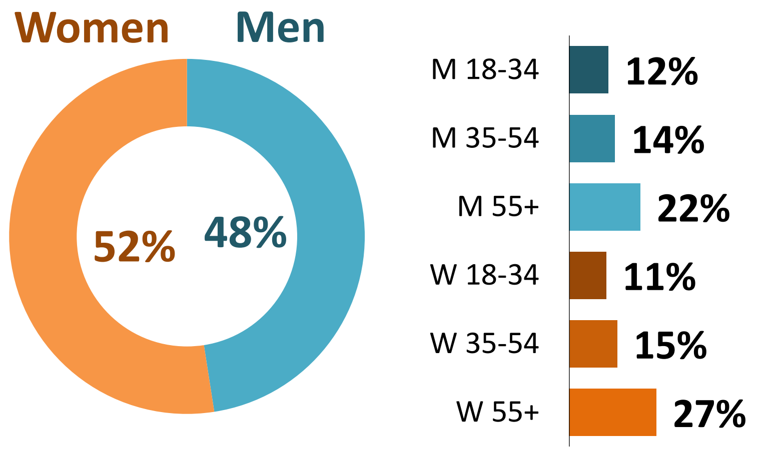
Method: Telephone
Field Dates: March 6th – March 11th, 2018
Sample Frame: Ontarian residents, 18 years or older, currently residing in Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, or Zurich
Sample Size: Total sample size n=415, n; weighted proportionately down to n=400.

2016 Public Awareness of Electrical Safety Scorecard survey

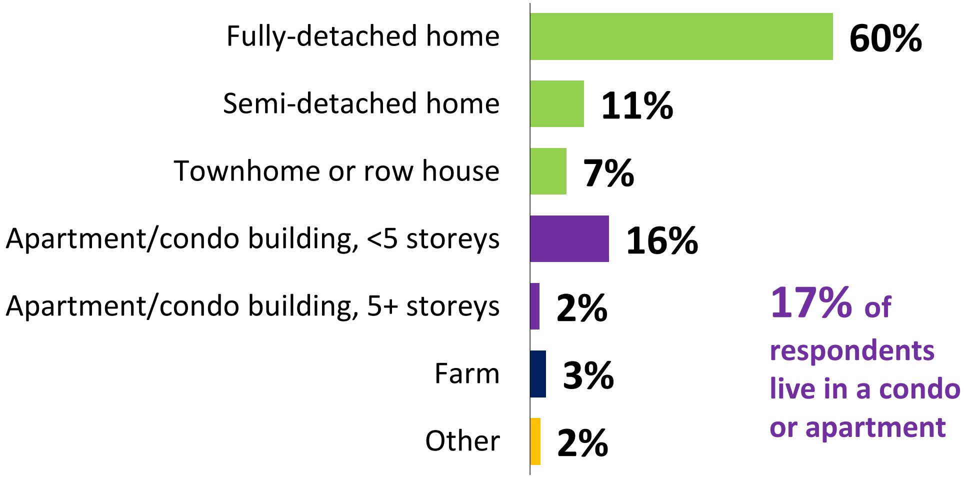
Method: Telephone
Field Dates: March 1st – March 5th, 2016
Sample Frame: Ontarian residents, 18 years or older, currently residing in Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth, or Zurich
Sample Size: Total sample size n=400, n; weighted proportionately to n=400.

Demographics | Respondent Profile

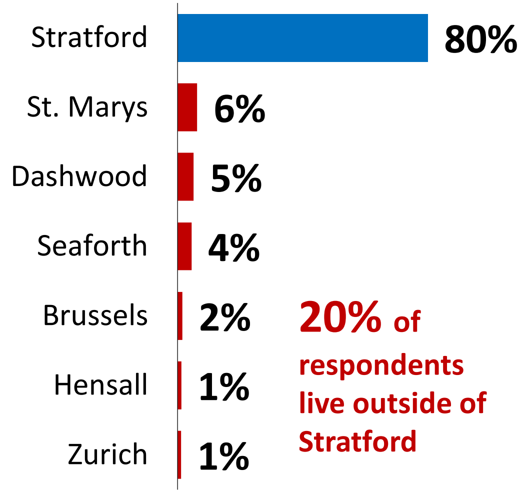
Age-Gender



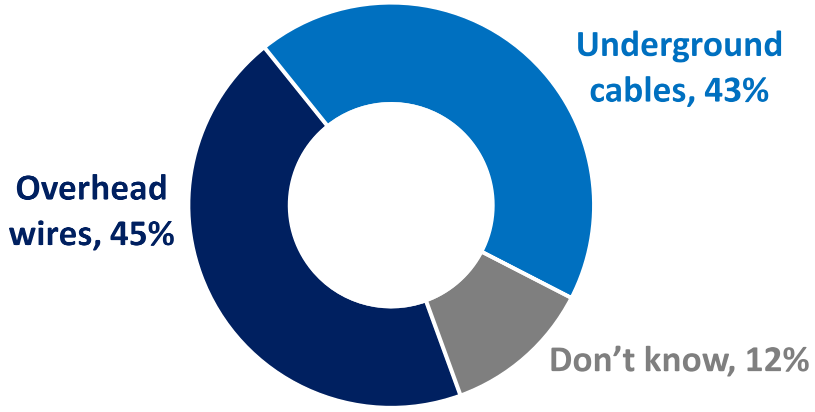
Primary Residence



Region

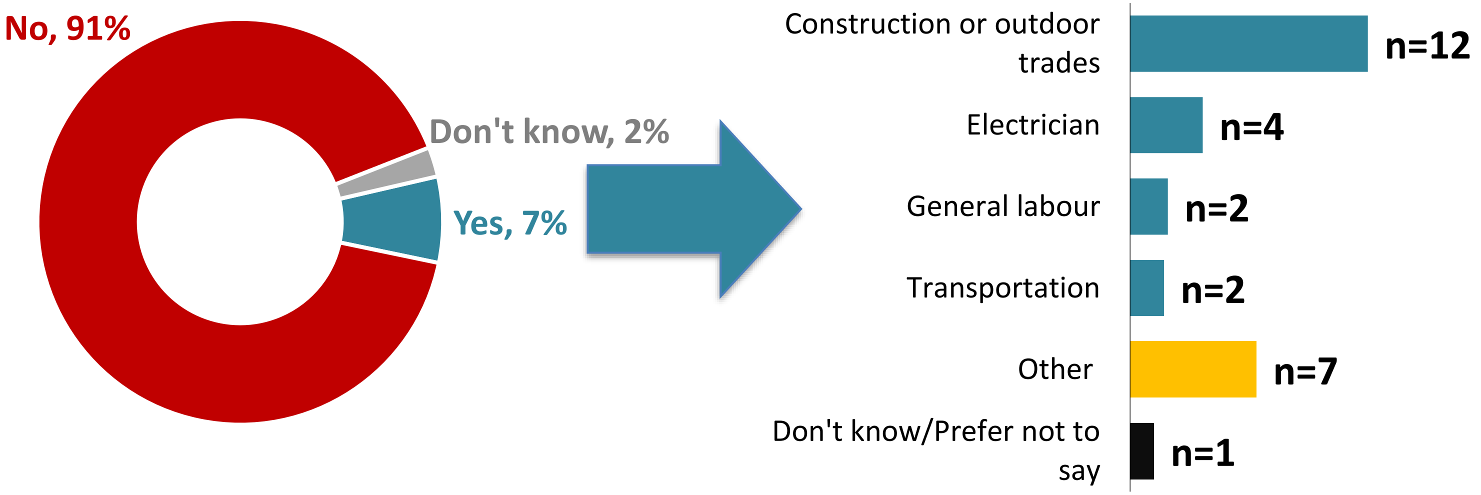


Does your primary residence receive electricity through …



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

Work close to power lines (n=27)



Awareness of Electrical Safety

INNOVATIVE
RESEARCH GROUP

Likelihood to Call Before You Dig

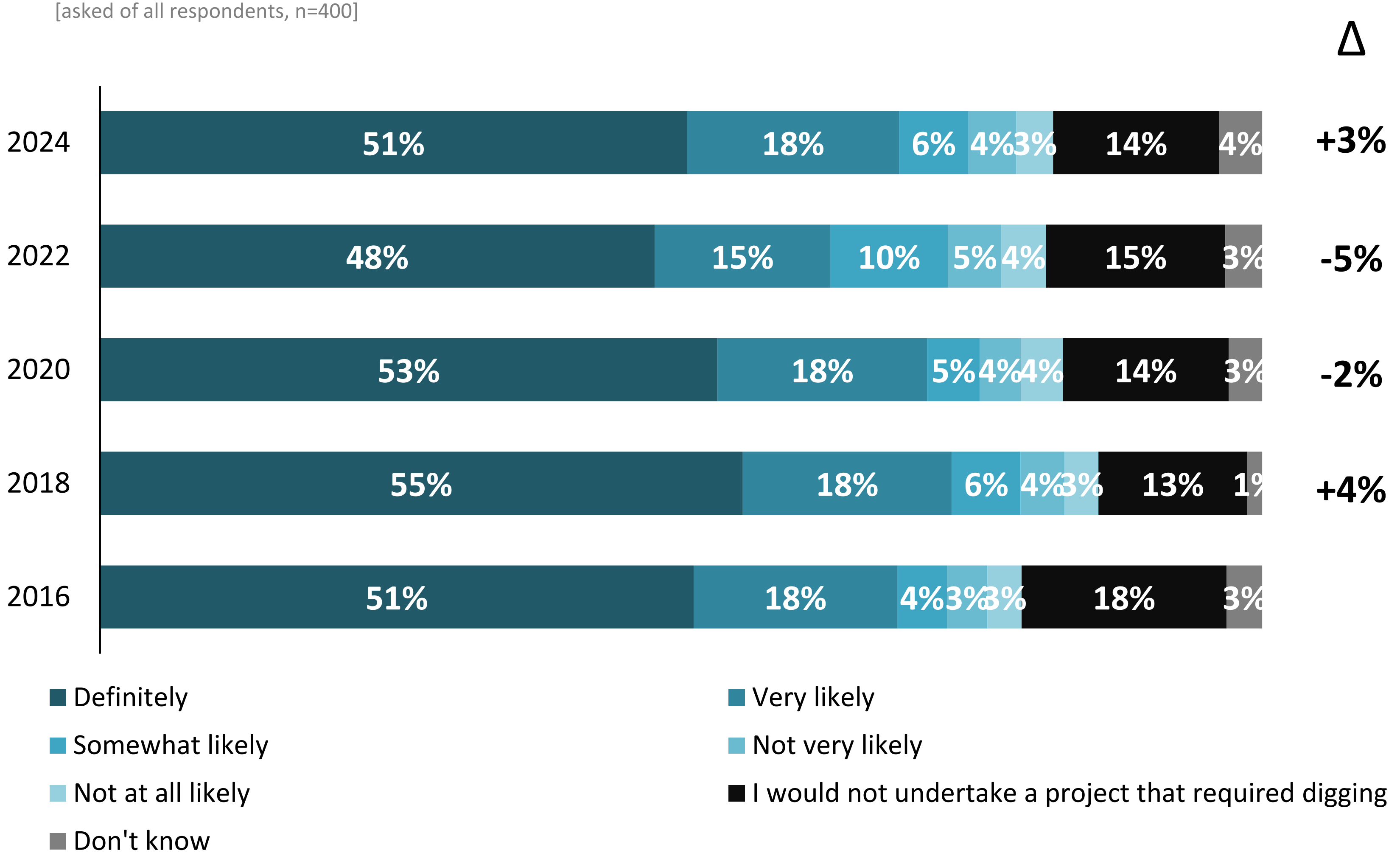
Half (51%) would 'definitely' call; highest among those who receive electricity through underground cables

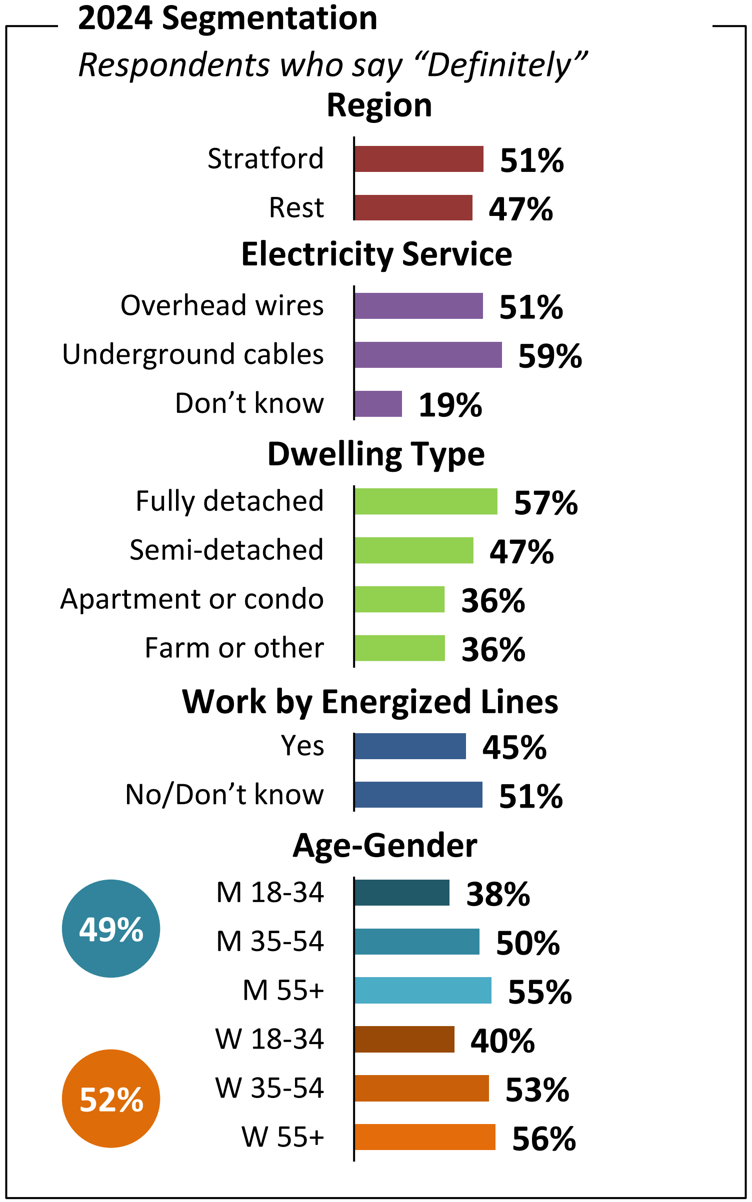
Q

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?

Best Answer: Definitely

[asked of all respondents, n=400]





Note: Differences that are statistically different from the previous wave of results (best answer) are highlighted in red (95% confidence) or blue (90% confidence).

Impact of Touching a Power Line

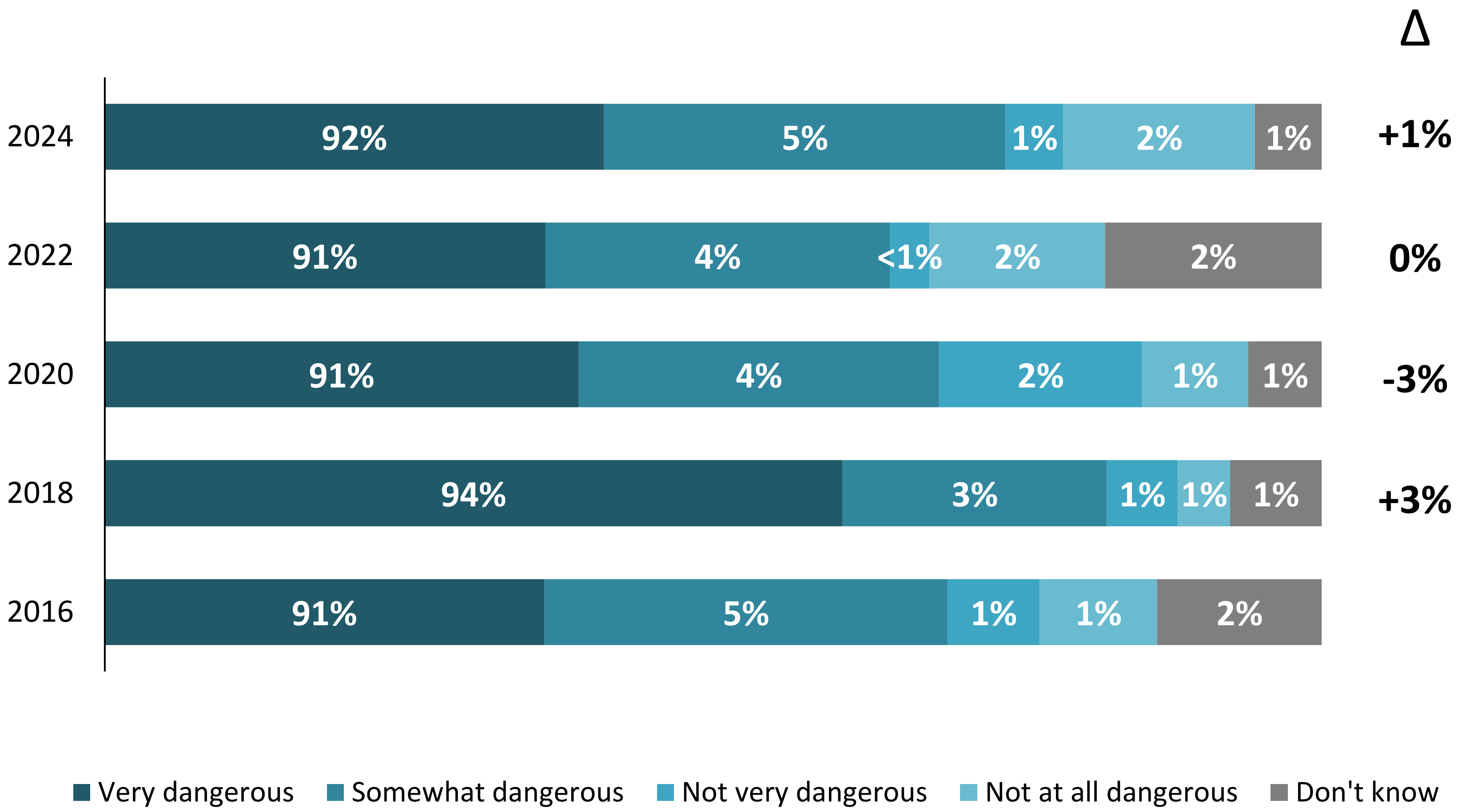
Almost all (92%) say 'very dangerous'; lowest among those in a farm or other type of dwelling

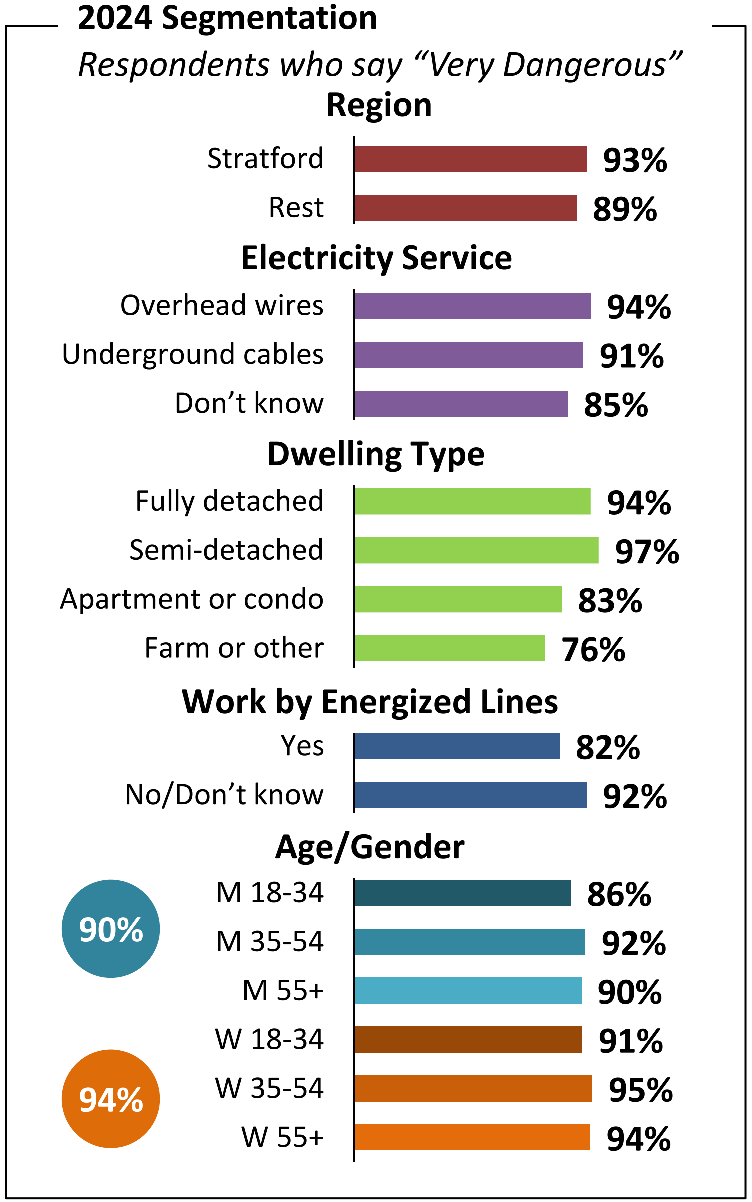
Q

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

Best Answer: Very Dangerous

[asked of all respondents, n=400]





Note: Differences that are statistically different from the previous wave of results (best answer) are highlighted in red (95% confidence) or blue (90% confidence).

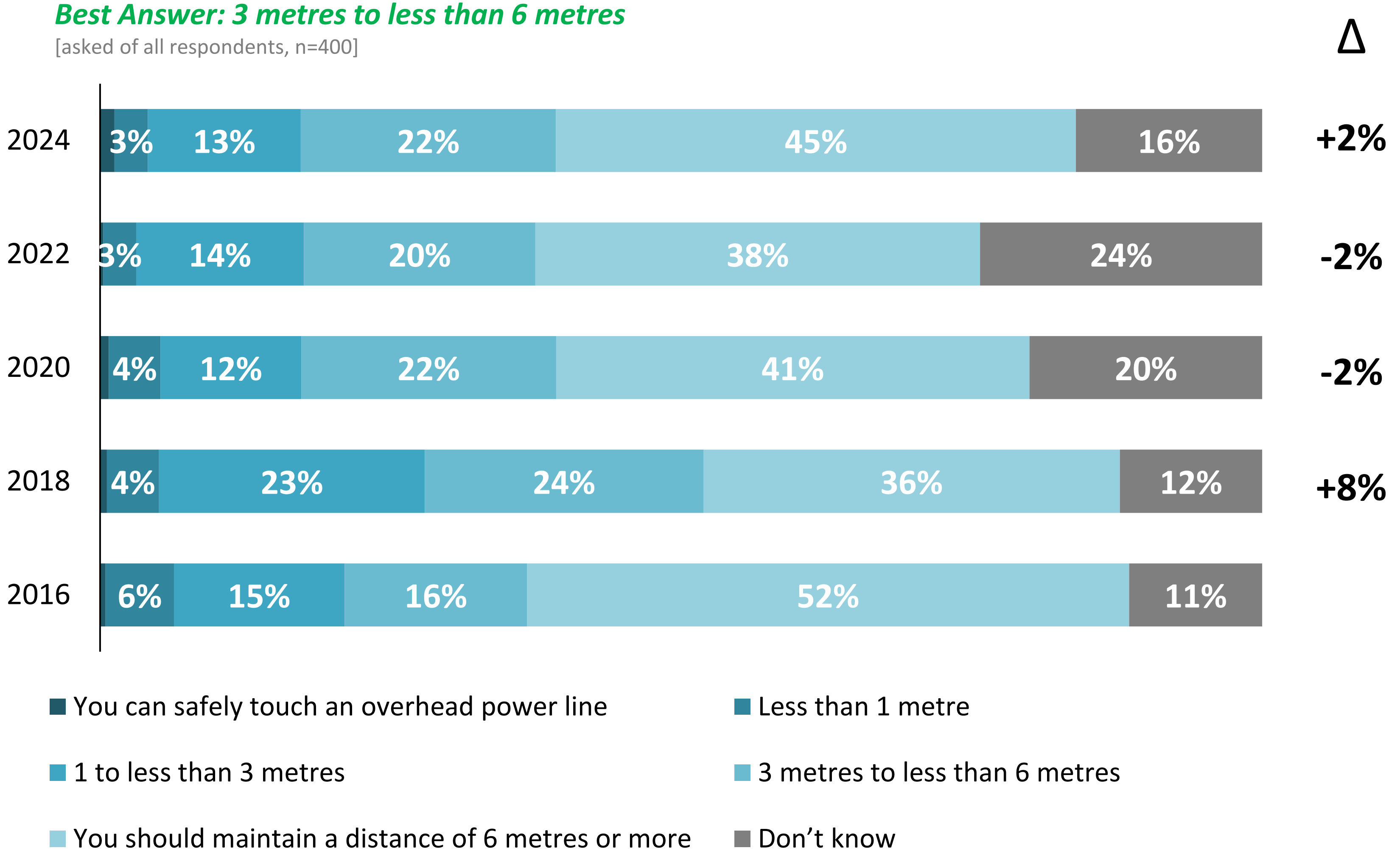
Proximity to Overhead Powerline

1-in-5 (22%) say '3 to less than 6 meters' is safe; lowest is among those who live in apartments or condos

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?

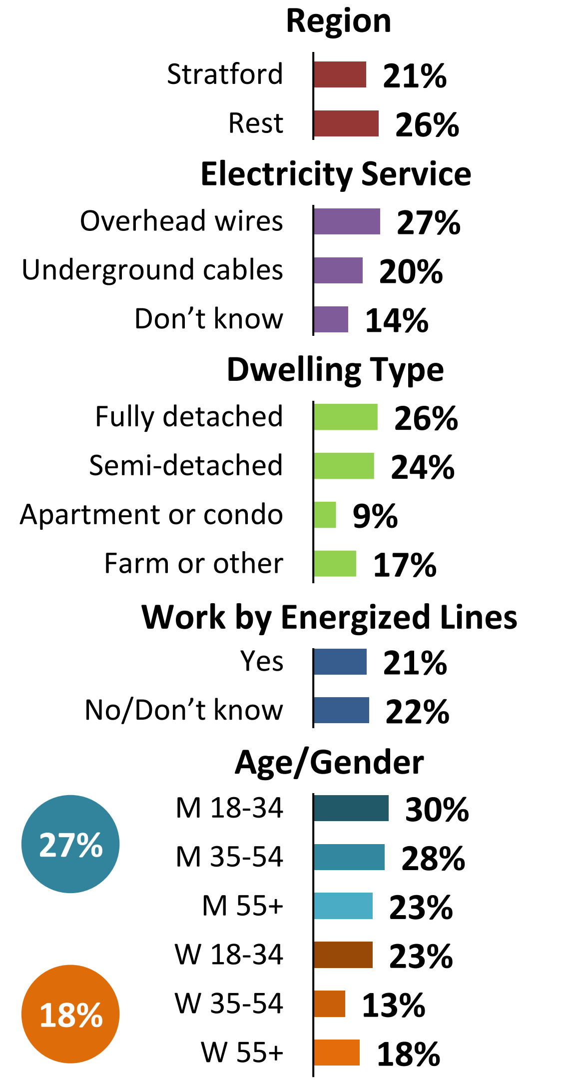
Best Answer: 3 metres to less than 6 metres

[asked of all respondents, n=400]



2024 Segmentation

Respondents who say "3m to <6m"



Note: Differences that are statistically different from the previous wave of results (best answer) are highlighted in red (95% confidence) or blue (90% confidence).

Danger of Tampering with Equipment

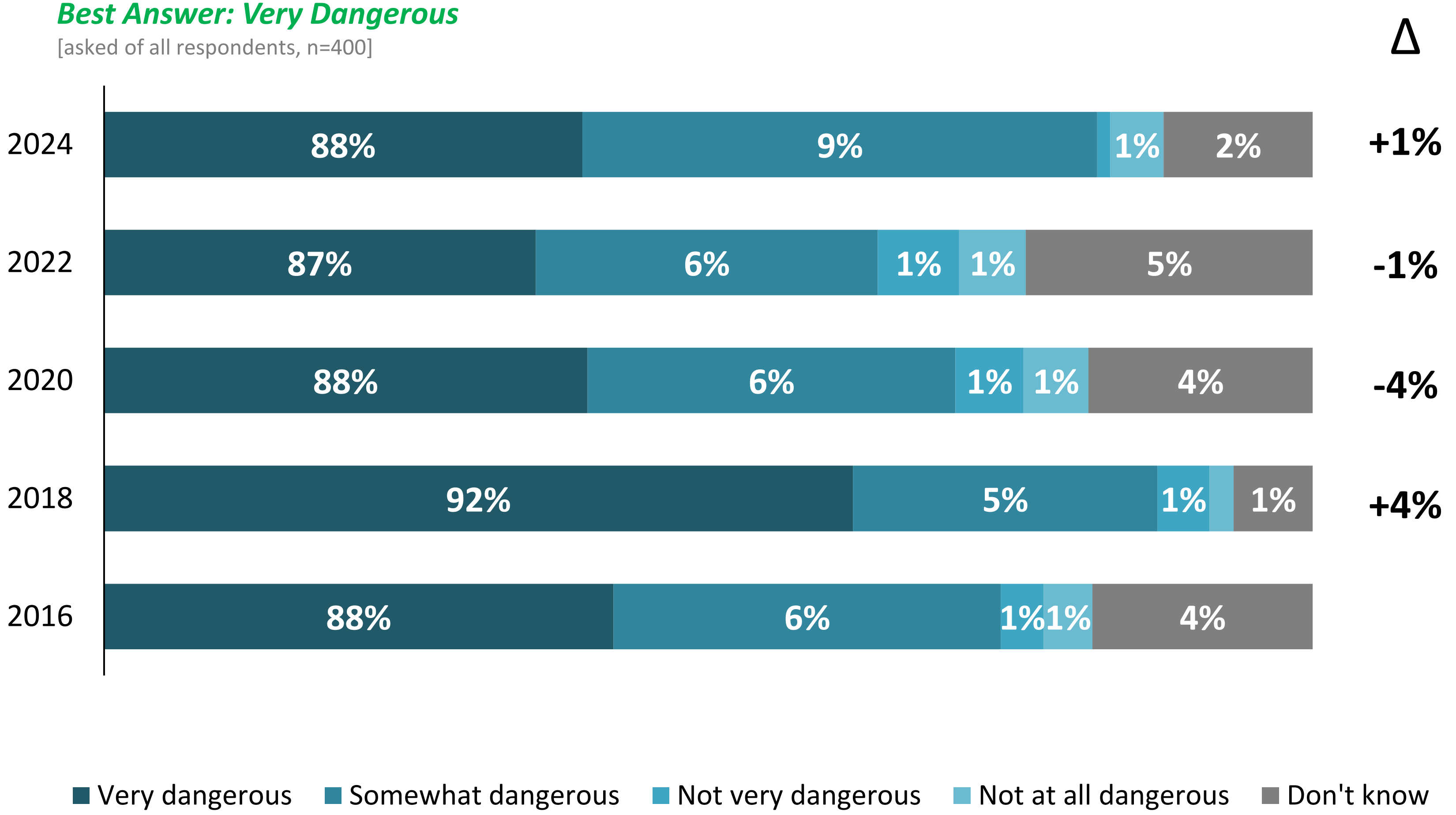
Almost all (88%) of the respondents say it's 'very dangerous' to tamper with equipment; highest among men aged 35-54

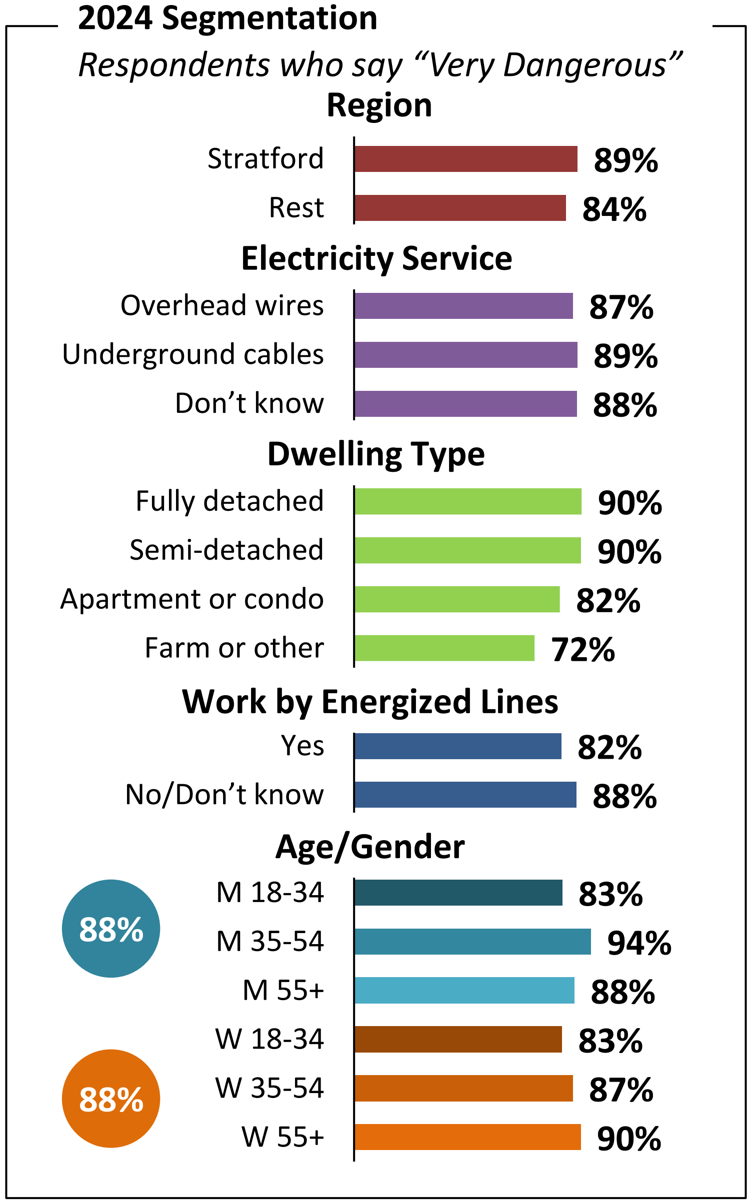
Q

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?

Best Answer: Very Dangerous

[asked of all respondents, n=400]





Note: Differences that are statistically different from the previous wave of results (best answer) are highlighted in red (95% confidence) or blue (90% confidence).

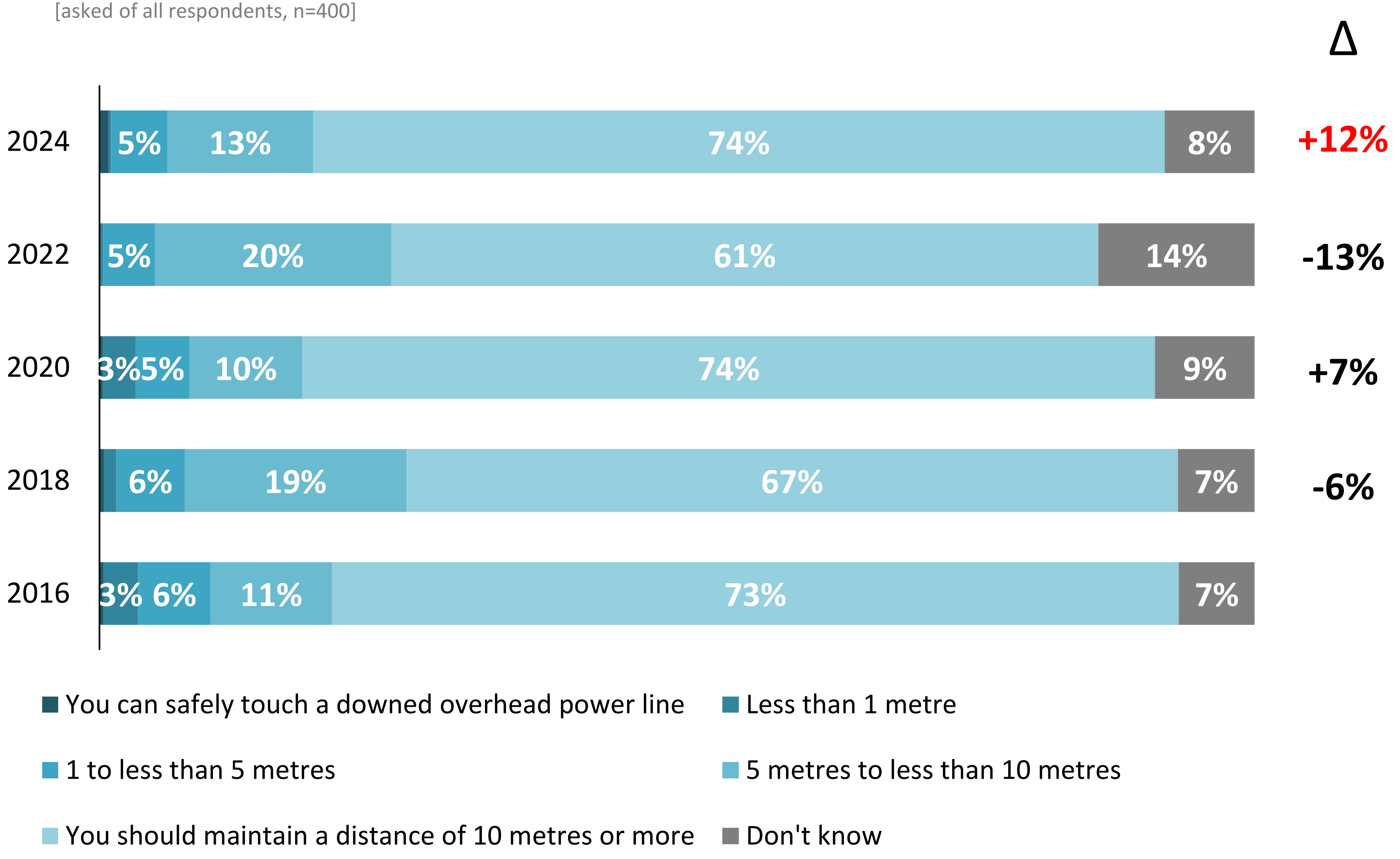
Proximity to Downed Power Line

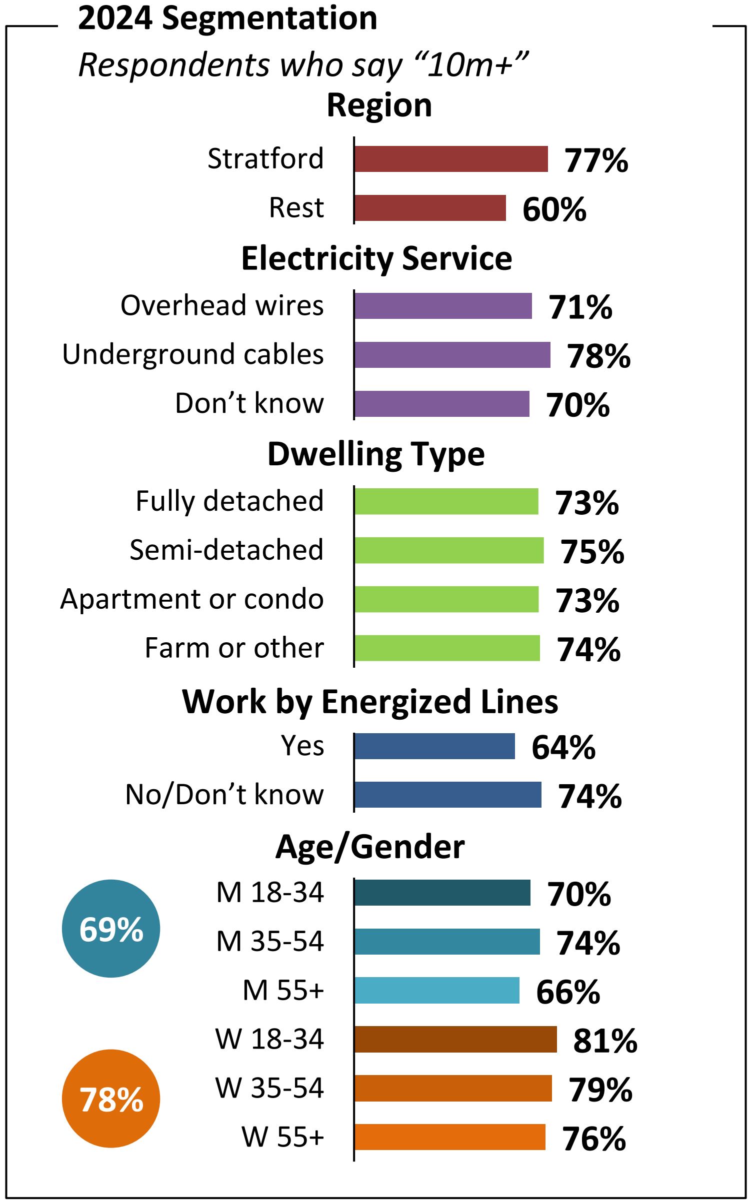
3-in-4 (74%) say '10 meters or more', up 13 points since 2022; highest among women aged 18-34

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?

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

[asked of all respondents, n=400]





Note: Differences that are statistically different from the previous wave of results (best answer) are highlighted in red (95% confidence) or blue (90% confidence).

Actions Taken in Vehicle in Contact with Wires

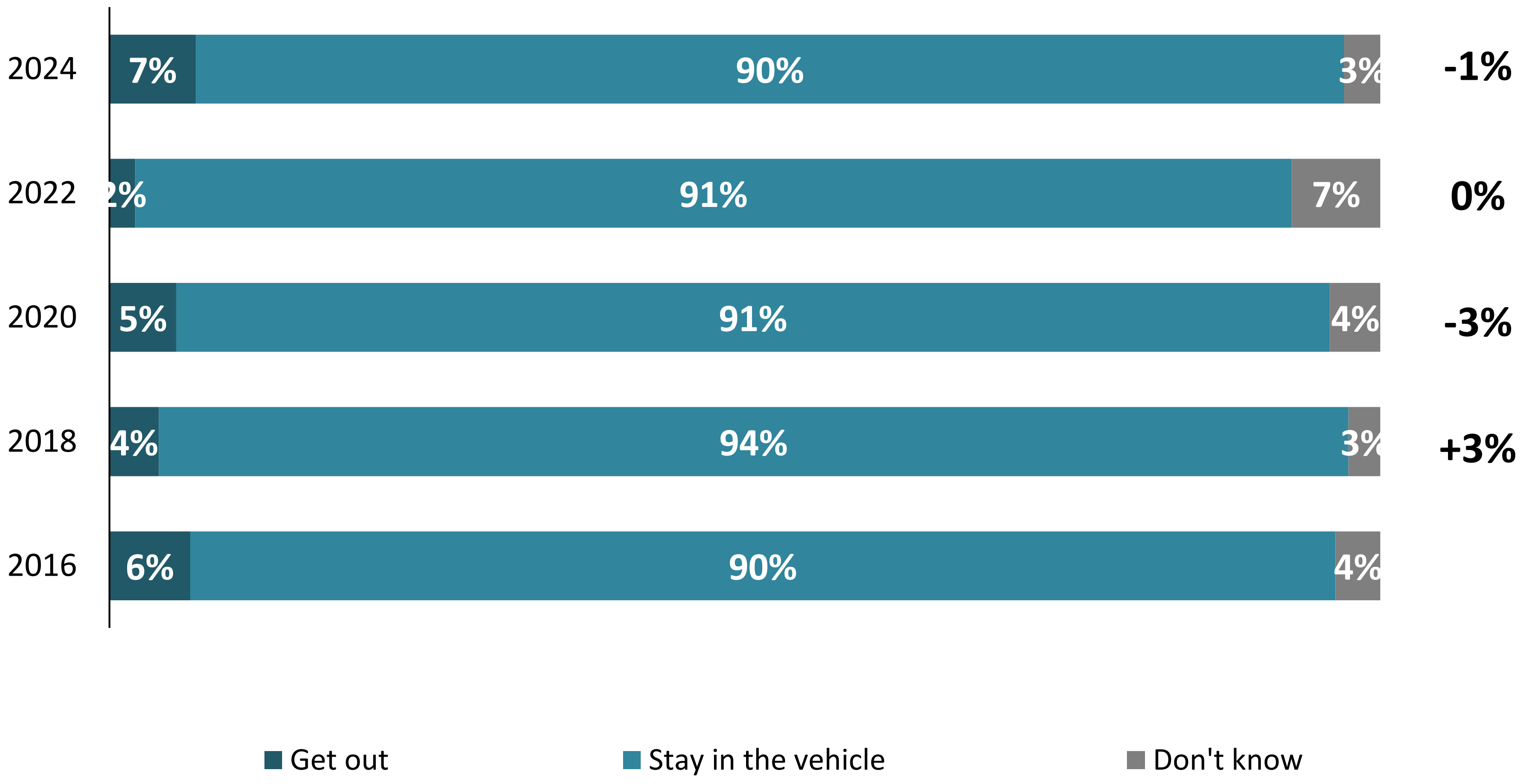
Nearly all (90%) respondents say to ‘stay in the vehicle’; results remained steady since 2016

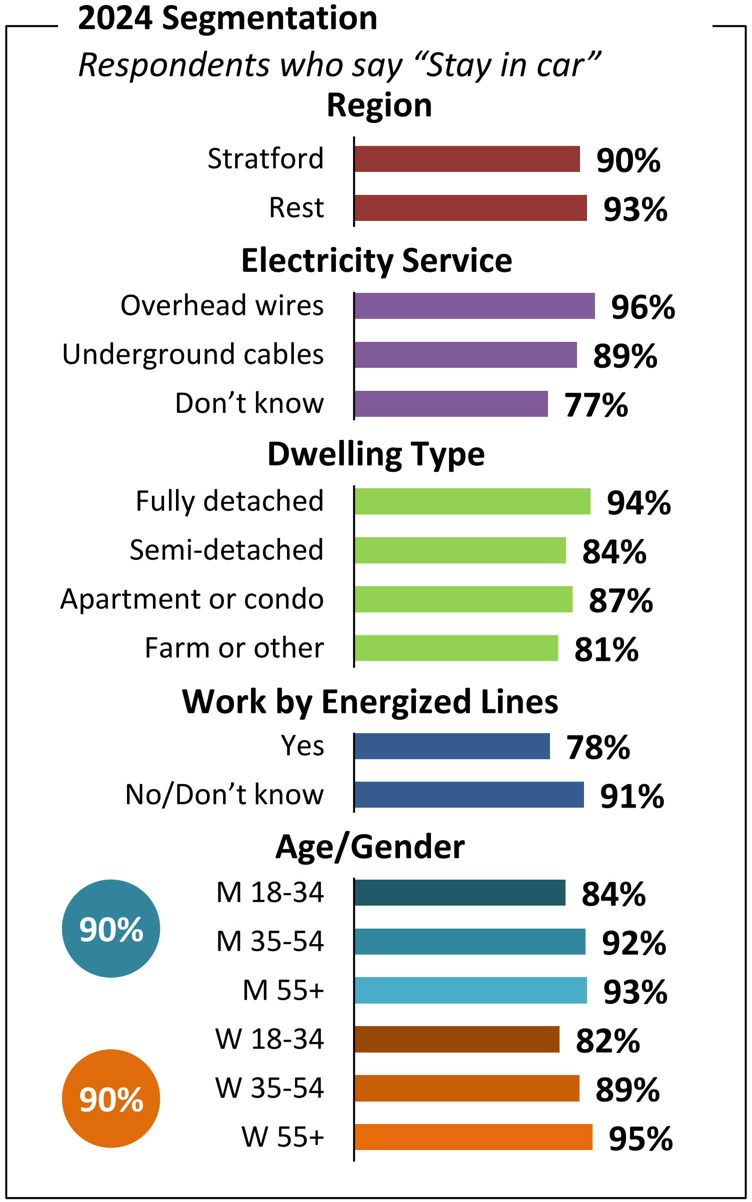
Q

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?

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

[asked of all respondents, n=400]





Note: Differences that are statistically different from the previous wave of results (best answer) are highlighted in red (95% confidence) or blue (90% confidence).

Actions Taken by Age-Gender

Women aged 18-34 are the least likely to choose 'stay in vehicle', followed by men aged 18-34

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?

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

[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	7%	14%	4%	3%	18%	8%	2%
Stay in the vehicle until power has been disconnected from the line	90%	84%	92%	93%	82%	89%	95%
Don't know	3%	2%	4%	4%	--	2%	3%

INNOVATIVE RESEARCH GROUP

Overall
Safety Awareness Score

INNOVATIVE
RESEARCH GROUP

Calculating the Public Safety Awareness Index Score

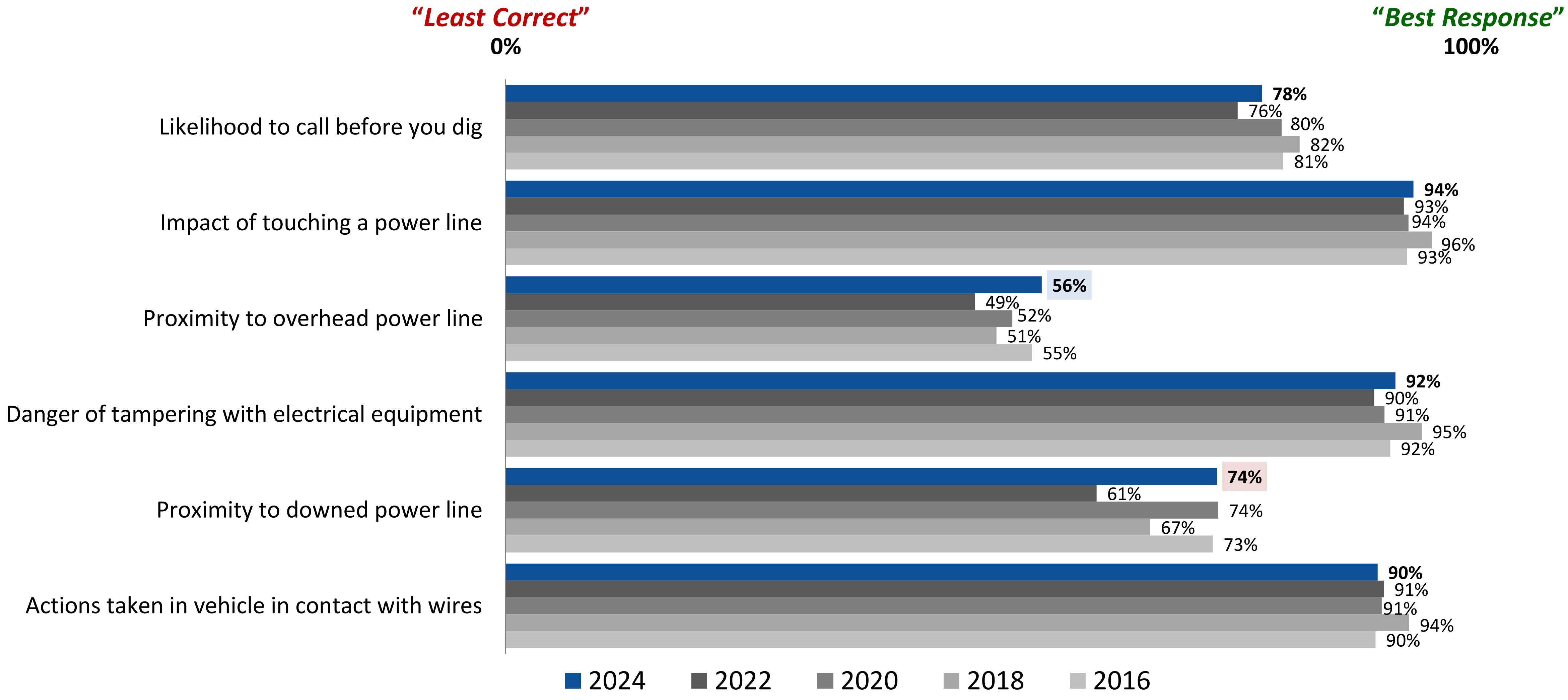
Each answer to core safety awareness questions will be allocated points based on the accuracy of the response. Responses deemed "*Best Answer*" will be allocated 1 point, while lesser answers will be awarded progressively less points. Responses are then indexed to create a single comparable Public Safety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

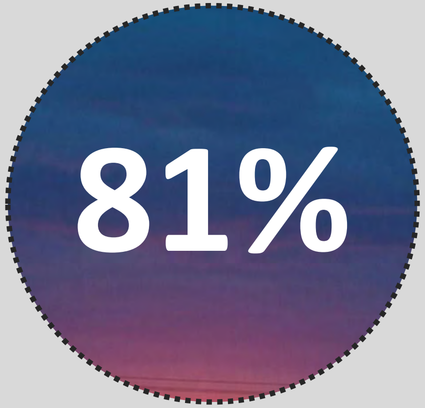


Note: Differences that are statistically different from the previous wave of results are highlighted in red (95% confidence) or blue (90% confidence).

Safety Awareness Score | Segmentation

Festival Hydro Inc.

2024 Safety Awareness Score



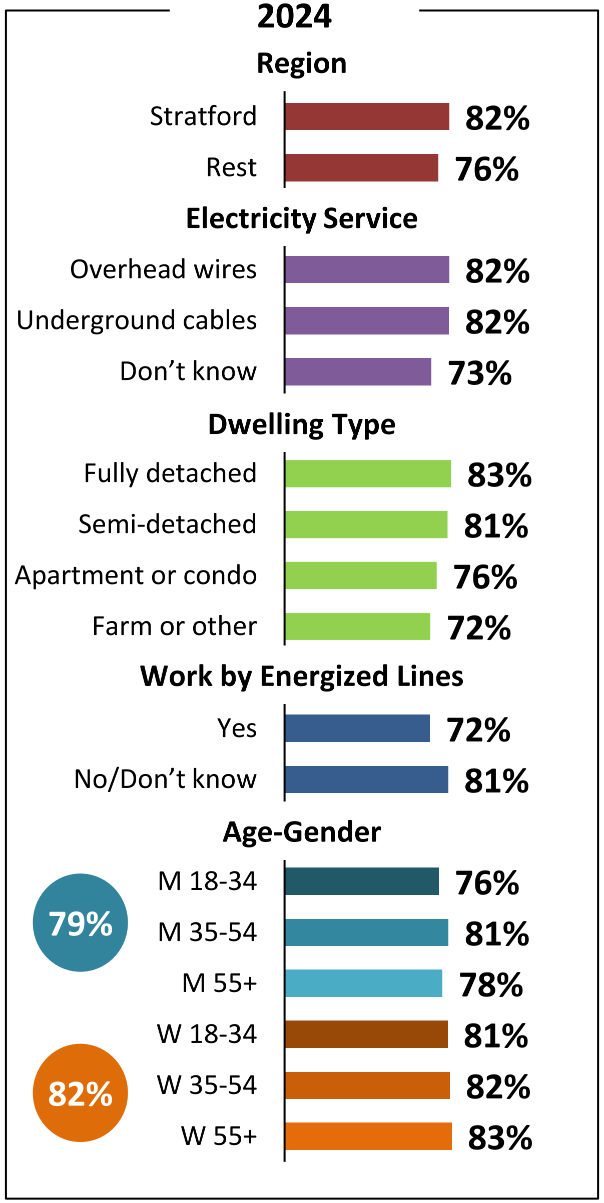
Historical Safety Awareness Scores:

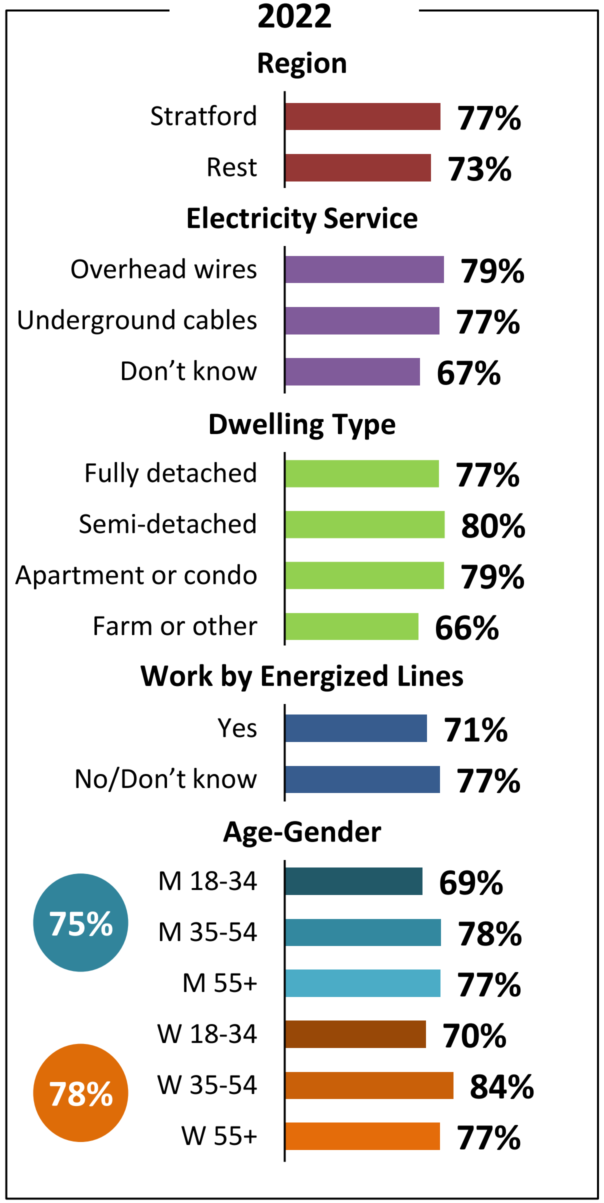
2022: 77%

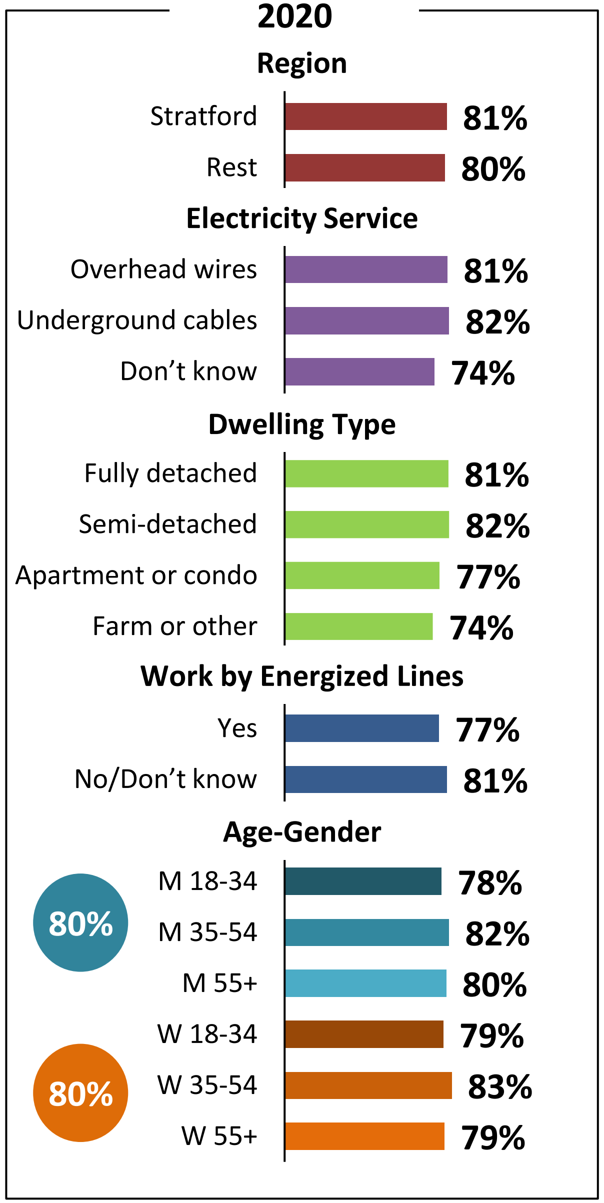
2020: 80%

2018: 81%

2016: 80%







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Martha Villarreal Lopez, Consultant
Cameron Moffatt, Research Analyst

Attachment 2

4-Staff-20 – Appendices A-C

RECOMMENDATIONS from the HR COMMITTEE MEETING Regarding the Executive & CEO Compensation Review

Meeting: December 12, 2023

FHI Compensation Philosophy

Is to attract and retain top talent and therefore utilizes a targeted job rate based on the market 50th percentile (P50) with a market salary range of P25 to P75, recognizing that newly promoted individuals should take a minimum of two years to reach the job rate.

Effective January 1, 2024, all salary ranges for the positions cited below include cost of living increases (COLA).

THE HR COMMITTEE RECOMMENDS:

1. For the positions of CFO and the Vice President, Engineering and Operations effective January 1, 2024, the P50 job rate be increased to $[redacted], with a minimum salary range of $[redacted] (80%) and a maximum of $[redacted] (120%).

2. For the position of Vice President, Information Technology effective January 1, 2024, the P50 job rate be increased to $[redacted], with a minimum salary range of $[redacted] (80%) and a maximum salary of $[redacted] (120%).

   Any incumbents are to be moved to the appropriate position within the range by the CEO in a fashion consistent with Festival Hydro's compensation philosophy, set out above.

   In addition, non-CEO executives are eligible for a performance incentive of 15% of base salary upon achievement of business objectives mutually agreed upon between the CEO and the non-CEO executive.

   The CEO, through the HR Committee, will advise the Board when an executive employee qualifies for a salary adjustment above the P50 job rate.

3. For the position of CEO effective January 1, 2024, the CEO receive an increase to $[redacted] (P50 job rate), with a minimum salary range of $[redacted] (80%) and a maximum of $[redacted] (120%).

   In addition, upon achievement of business objectives mutually agreed upon between the Board and the CEO, that the CEO be eligible for a target incentive of 25% of base salary with an incentive range of 0.5 times to 1.35 times the target of 25% of base salary.

Festival Hydro Inc.
President & CEO Compensation Review

Final Report to Board of Directors

December 14, 2023

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Current Compensation

- Festival Hydro's incumbent President & CEO was appointed to the role in early September of 2021
  - Internally promoted from VP of Engineering & Operations, after having acted as Interim President & CEO for about two months
- Incumbent President & CEO's salary is at the current job rate, established in 2021
  - Following the last market review in 2021, the expectation was set with the incumbent President & CEO to move to the new job rate (based on the 2021 market) after two full years of successful performance in the role, as well as the establishment of an incentive plan, effective for the 2022 fiscal year
- In January of 2023, the incumbent President & CEO, received a [redacted] increase in salary, and a target bonus increase to 25% for 2023 (had been at 15% for 2022)
  - Current mix between fixed and variable pay is 80% fixed / 20% variable

Salary Range	Minimum Salary (80%)	FHI Job Rate (100%)	Maximum Salary (120%)
President & CEO	[redacted]	[redacted]	[redacted]

Compensation Element	President & CEO Compensation	Compensation Mix (% of Total Cash)
Base Salary	[redacted]	80%
Bonus (at 25%)	[redacted]	20%
Total Cash	[redacted]	

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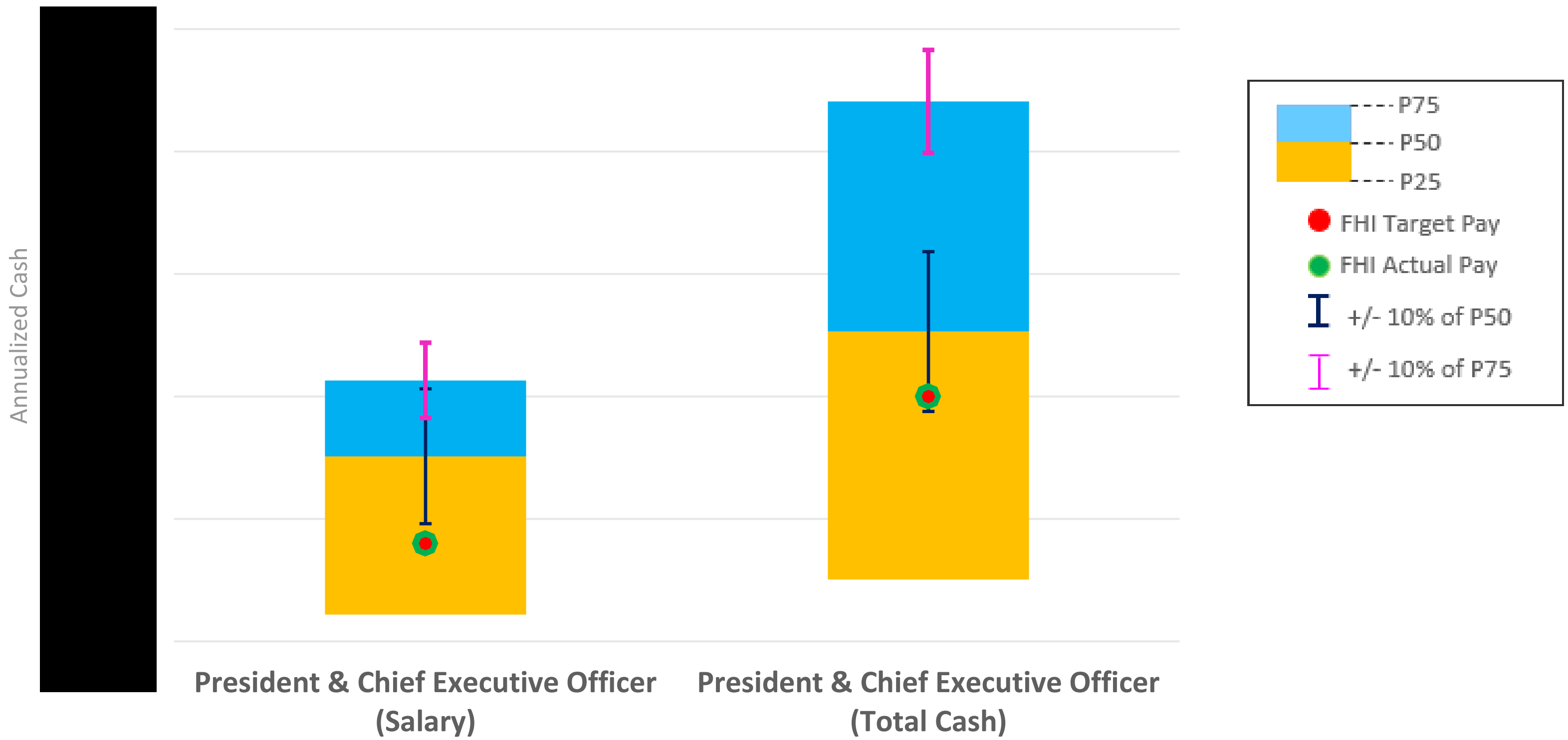
President & Chief Executive Officer



Internal Position	# of Incumbents	FHI Actual Pay	FHI Design Pay	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
President & CEO (Salary)	31	[redacted]								P50 = 26.25% P75 = 38.45%
President & CEO (Total Cash)	31									

Recommendation

CEO Recommendations - Salary

- LBCG recommends increasing the target job rate (salary range midpoint) for the President & CEO role by [redacted] to approach the market rate
  - [redacted] increase in job rate
- Additionally, LBCG recommends maintaining the current target bonus amount of 25% of base salary, consistent with market target bonus level and to maintain the current compensation mix

Current Range

Executive Position	Minimum (80%)	FHI Job Rate (100%)	Maximum (120%)
President & CEO	[redacted]	[redacted]	[redacted]

[redacted]

Proposed Range

Executive Position	Minimum (80%)	FHI Job Rate (100%)	Maximum (120%)
President & CEO	[redacted]	[redacted] ~ P50	[redacted]

Around P75 of [redacted]

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Proposed Total Cash Range

Target Bonus of 25%

For new hires or new in a role at this organizational level or promotions.

For fully experienced in role and consistently meeting expectations.

For sustained exceptional performance and to serve as a pay maximum.

Salary	*Building Capability* Range Minimum (80%)	*Proficient with Solid Performance* Range Midpoint (100%)	*Sustained High Performance* Range Maximum (120%)
President & CEO	[redacted]	[redacted]	[redacted]

At market P25 of [redacted]

At market P50 of [redacted]

Close to market P75 of [redacted]

Total Cash Target Bonus of 25%	Range Minimum (80%)	Range Midpoint (100%)	Range Maximum (120%)
President & CEO	[redacted]	[redacted]	[redacted]

Above market P25 of [redacted]

Close to market P50 of [redacted]

Slightly below market P75 of [redacted]

Costing

President & CEO Cost

- Given that the incumbent President & CEO has been in the role for just over two years, the incumbent's salary should increase to at least the midpoint/job rate as he has achieved full proficiency in the role and is meeting performance expectations
- Target bonus to remain at 25% as this is market-competitive and maintains the prevalent compensation mix in the LDC market of 80/20 fixed/variable
  - Incremental increase for this role is [redacted]

President & CEO	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
Current	[redacted]	25%	[redacted]	[redacted]	[redacted]	[redacted]
Proposed	[redacted]	25%	[redacted]	[redacted]	[redacted]	[redacted]
Change (%)	[redacted]	0%	[redacted]	[redacted]	[redacted]	[redacted]
Change ($)	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

*Additional cost for benefits is only applied to base salary.

Total Incremental Costs

- The total incremental cost for the recommended salary increases for all four executives, including benefits load, is ~[redacted]
  - These increases in salary of [redacted] total corresponds to an [redacted] increase to total executive salary load (payroll) of the four executives
  - Costs assume merit increases for the VP of Engineering & Operations, for the Chief Financial Officer, and for the President & CEO incumbents
  - Costs also assume that performance targets will be met as bonus amounts are costed at target payout levels

Executive Position	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
President & CEO	[redacted]	25%	[redacted]			
Three Executives		15%				
Change ($)						

*Additional cost for benefits is only applied to base salary.

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Appendix

Other Options Modelled

- Other options were modeled to increase the President & CEO's compensation to market-competitive levels by increasing both the salary and bonus target, thereby shifting the compensation mix

A: Increase salary and target bonus

President & CEO	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
Current	[redacted]	25%	[redacted]	[redacted]	[redacted]	[redacted]
Proposed	[redacted]	30%	[redacted]	[redacted]	[redacted]	[redacted]
Change (%)	[redacted]	20%	[redacted]	[redacted]	[redacted]	[redacted]
Change ($)	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

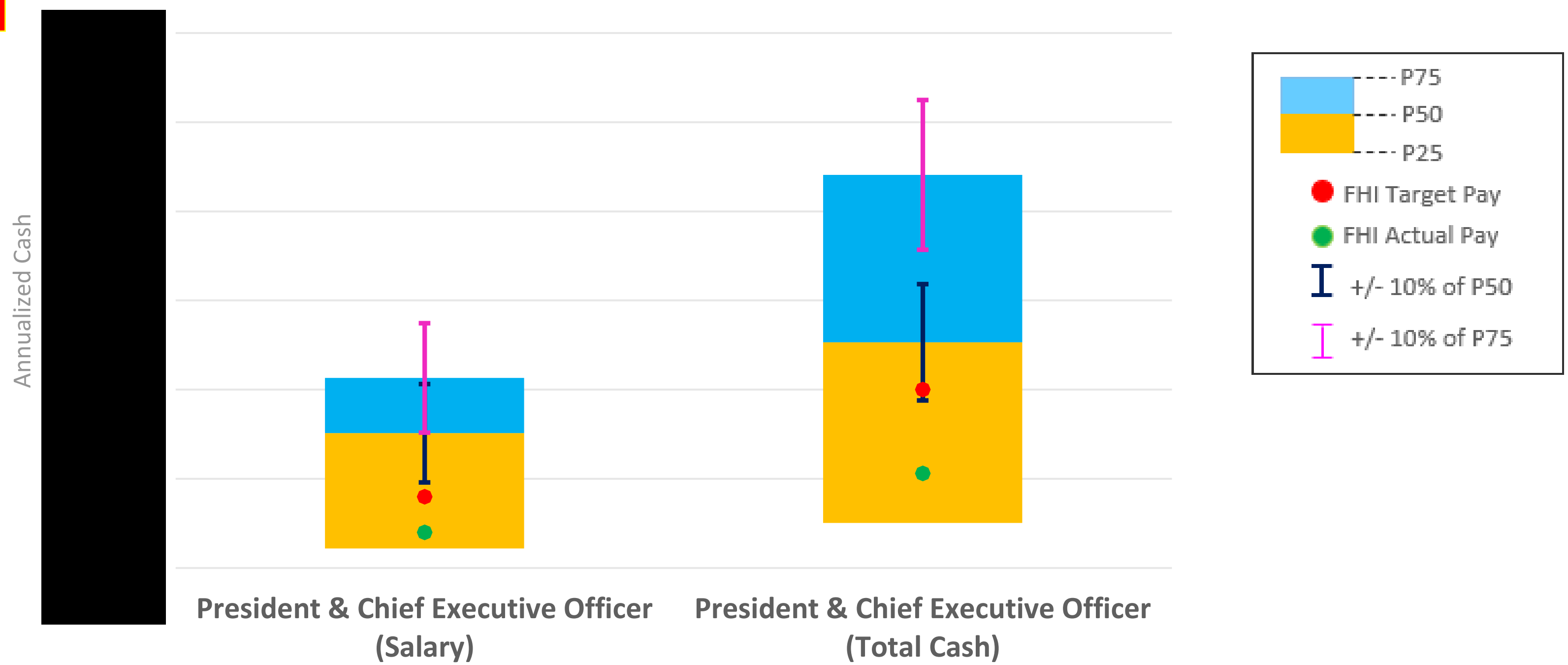
B: Modest salary increase and target bonus

President & CEO	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
Current	[redacted]	25%	[redacted]	[redacted]	[redacted]	[redacted]
Proposed	[redacted]	30%	[redacted]	[redacted]	[redacted]	[redacted]
Change (%)	[redacted]	20%	[redacted]	[redacted]	[redacted]	[redacted]
Change ($)	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

*Additional cost for benefits is only applied to base salary.

Incumbent's 2022 Compensation

President & Chief Executive Officer



Internal Position	# of Incumbents	FHI Actual Pay	FHI Design Pay	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
President & Chief Executive Officer (Salary)	31	[redacted]								P50 = 26.25% P75 = 38.45%
President & Chief Executive Officer (Total Cash)	31									

Recommendation from 2021 President & CEO Compensation review

Recommendations

Short-Term

1. Implement a compensation strategy and target level of pay based on the market 50th percentile
2. The Board needs to provide guidance on whether incentive pay plan is intended to bring compensation to market P50 level or to exceed market (to P75) for overperformance on annual objectives
3. Establish parameters for incentive pay plan, including maximum payout for overperformance and minimum threshold of bonus payout
   - In LDC market, average maximum payout is 1.35x target amount for CEOs
   - In LDC market, typical bonus rate for threshold performance is 50% of target bonus amount

Medium-Term

4. Set expectations with incumbent President & CEO around future substantial increases in base salary being tied to the LDC market moving, once compensation reaches market level
5. Continue practice of annual COLA as it is prevalent market practice and entrenched within LDCs

Recommendation from 2021 President & CEO Compensation review

ase in Salary and Target Bonus

Shifting the Mix of Fixed vs. Variable Compensation

- Enhance the variable pay component with a formalized incentive pay plan to the President & CEO compensation offering
    - Market-competitive bonus target for President & CEO role is 25%
- For 2022, increasing base salary by [redacted] to [redacted] and adding a 25% target bonus opportunity would increase target total cash by [redacted]
- For 2023, increasing salary by another [redacted] to [redacted] with a 25% target bonus would further increase target total cash by $[redacted]
- Any compensation increase will cost FHI an additional 25% for benefits and pension, assuming that bonus amounts would be pension eligible earnings

	Salary	Target Total Cash	Target Bonus ($)	Target Bonus (%)	Total Cash Mix (Fixed)	Total Cash Mix (Variable)
Current	[redacted]	[redacted]	[redacted]	5%	95.2%	4.8%
Proposed (Yr 1)	[redacted]	[redacted]	[redacted]	25%	80%	20%
Proposed (Yr 2)	[redacted]	[redacted]	[redacted]	25%	80%	20%

MEARIE Survey Participant List

2023 Management Salary Survey of Local Distribution Companies

Alectra Utilities Inc.
Bluewater Power Distribution
Burlington Hydro Inc.
Centre Wellington Hydro Ltd.
E.L.K. Energy Inc.
Elexicon Energy Inc.
Enova Power Corp.
Entegrus Powerlines Inc.
ENWIN Utilities Ltd.
EPCOR Electricity Distribution Ontario Inc.
ERTH Power Corporation
Essex Powerlines
Festival Hydro Inc.
Fort Frances Power Corporation
GrandBridge Energy Inc.
Greater Sudbury Utilities
Grimsby Power Inc.
Halton Hills Hydro Inc.
InnPower Corporation

Kingston Hydro
Lakeland Power Distribution Ltd.
London Hydro Inc.
Milton Hydro Distribution Inc.
Newmarket-Tay Power Distribution Ltd.
Niagara Peninsula Energy Inc.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Orangeville Hydro Limited
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Peterborough Utilities Group
PUC Services Inc.
Rideau St. Lawrence Distribution
Sioux Lookout Hydro Inc.
Synergy North
Wasaga Distribution Inc.
Welland Hydro-Electric System Corp.

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Thank you!

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Festival Hydro Inc.
Executive Compensation Review

Final Report to Board of Directors

December 14, 2023

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Agenda

- Approach
- Current Salary Structures
- Compensation Framework
  - Annual Salary Increases
  - Incentive Payout Ranges
- Market Review
- Recommendations
  - Design Considerations
  - Proposed Ranges
  - Costing

Approach

Festival Hydro Data and Scoping

- Consultation with CEO, all Executives, Board Chair and HR Committee Chair
- Document review
- Explore views on paying for performance, variable pay and mix of compensation

Market Data Review

- Identify benchmark jobs for market comparison
- Assess job scope comparability
- Review quantitative market compensation data

Data Analysis and Reporting

- Compare market data to current salaries and bonus targets
- Assess ranges and recommend adjustments for external equity
- Determine any cost impact

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Current Salary Structure

- Festival Hydro has a tenure-based salary band structure for its non-unionized employees below the Executive level, which includes for the Director of People and Safety
  - 6 steps in each salary band, with the top step being the job rate that takes 5 years to achieve
- Structure has a consistent 4% increase between successive steps
- There are two levels of pay for the VPs, with the first level having a [redacted] increase from the Director top step/job rate
  - The second level of VP pay has a [redacted] increase from the first level of VP pay

Step 1	Step 2	Step 3	Step 4	Step 5	Step 6
80%	84%	88%	92%	96%	100%

4% 4% 4% 4% 4%

Pay Level	Director	VP I	VP II	CEO
Increase in Job Rate		[redacted]	[redacted]	[redacted]

Executive Salary Structure

- Festival Hydro has two levels of pay for its Executive roles with the job rate (midpoint of the salary range) calibrated to the middle of the external LDC market and the maximum tied to the market top quartile (75th percentile)
  - The salary range for the CFO and the VP of Engineering & Operations has a midpoint about [redacted] than the midpoint for the VP of Information Technology
- Current practice is to start new incumbents below their salary range midpoint and to move to midpoint as they build capability over time

VP – Salary	Minimum (80%)	FHI Job Rate (100%)	Maximum (120%)
CFO VP of Engineering & Operations	[redacted]		
VP of Information Technology			

VP – Total Cash (with 15% Target Bonus)	Minimum (80%)	FHI Job Rate (100%)	Maximum (120%)
CFO VP of Engineering & Operations	[redacted]		
VP of Information Technology			

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Compensation Framework

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Annual Salary Increases

Cost-of-Living Adjustment

- Common market practice is to provide annual increases as cost-of-living adjustments (COLA) to employees at all organizational levels within LDCs
  - Many LDCs also increase the salary ranges every year
- COLAs are often tied to the negotiated general wage increases in the collective agreements for an LDC's unionized staff
- Festival Hydro's budgeted increase for 2024 is [redacted] for non-unionized staff
  - Current practice has been to provide the increase each January
- The table below represents average salary increases in 2023 and projected increases for 2024 in the LDC market

	FHI 2024 Projected Salary Increase*	2023 Market Salary Increase	2024 Projected Market Salary Increase
Executive/VP	[redacted]		
Director			

*This amount is for 12 months, effective in January.

Incentive Payout Ranges

- Variable / incentive pay plans that are target based typically have a target amount that is a percentage of base salary to be paid out with the successful achievement of specific goals and objectives
- Incentive plan designs typically have a range of payout levels around the bonus target amount
  - Plan participants have expectations of payout at target or above or below, depending on both organizational and individual performance outcomes
  - Superior performance, or overachievement of performance targets can result in payouts above target, which should result in above-market compensation, and conversely, performance below expectations or underachievement could result in below-market compensation (and bonus payouts below target)
- Currently, Festival Hydro's maximum bonus target payout level for overachievement on all metrics is 1x

Position	President & CEO	Executive / VP	Director
Festival Hydro			
Maximum Payout	**1.0x**	**1.0x**	**1.0x**
Payout at Threshold	**0.8x**	**0.8x**	**0.8x**
LDC Market			
Maximum Payout - average	1.40x	1.39x	1.31x
Maximum Payout - modal	*1.0x*	*1.0x*	*1.0x*
Payout at Threshold – average	0.55x	0.54x	0.52x
Payout at Threshold – modal	*0.5x*	*0.5x*	*0.5x*

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Market Review

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Market Segments

- In reviewing the market data, multiple market segmentations were assessed and compared for each Executive position
  - In general, the market values were fairly consistent with the overall sample of all participating LDC organizations and thus used for market comparison figures throughout this report

Metric	LDC Market Median	Market Segment	Festival Hydro
Number of Customers	28,324	20,000 to 39,999	22,500
Number of Full-Time Equivalent Employees	55 FTE	20 to 49.9 FTE	41 FTE
Gross Revenue	$19.6 Million	$10 to $20 Million	$11.5 Million
Region in Ontario	All	Southern Ontario	Southern Ontario

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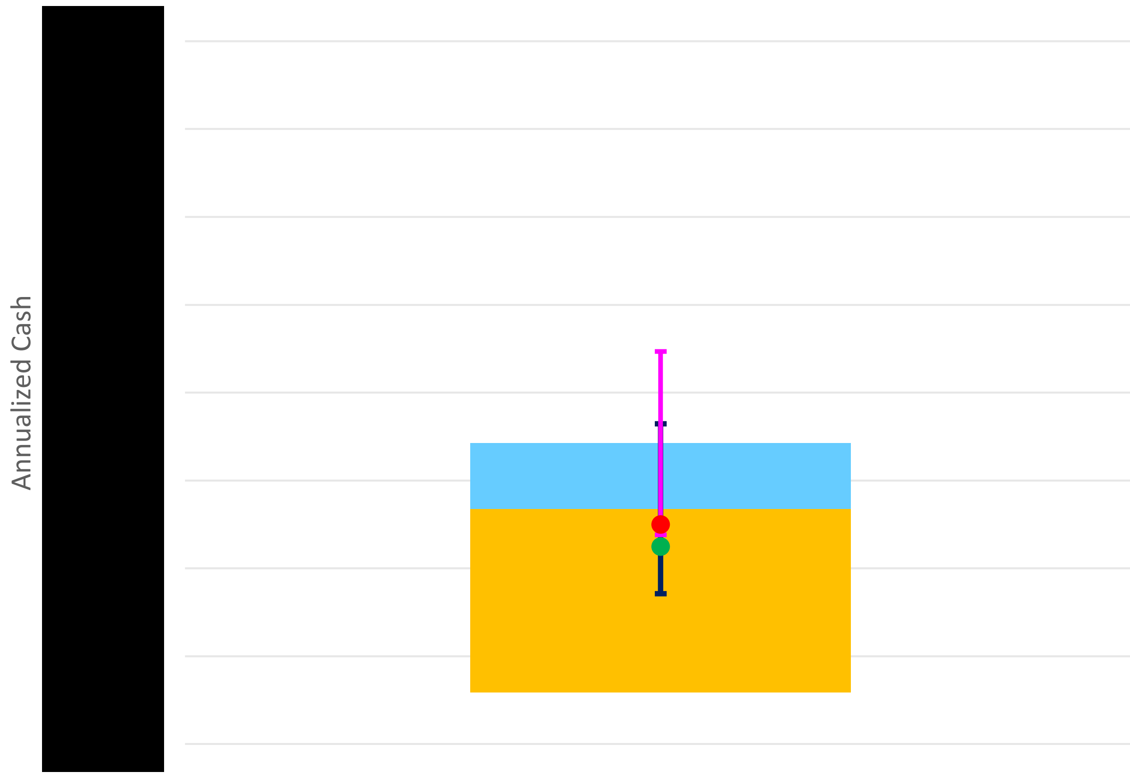
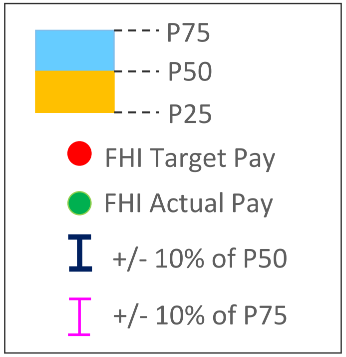
Presentation of Data





Internal Position	# of Incumbents	FHI Actual Pay	FHI Design Pay	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
Xxx	Xx	$xxx,xxx	$xxx,xxx	$xxx,xxx	xx%	$xxx,xxx	xx%	xx%	xx%	P50 = xx% P75 = xx%
Position Title at FHI	Number of incumbents included in analysis	Actual Salary or Total Cash at FHI	Job Rate or Job Rate plus Target Bonus at FHI	P50 Market Rate for job from MEARIE survey of LDCs	Actual pay as a percentage of market P50	P75 Market Rate for job from MEARIE survey of LDCs	Actual pay as a percentage of market P75	Design pay as a percentage of market P50	Design pay as a percentage of market P75	P50 / P75 Market Target Bonus as percent of salary

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Director of People and Safety

Internal Position	# of Incumbents	FHI Actual Pay*	FHI Design Pay (Midpoint)	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
Director of People & Safety (Salary)	17	[redacted]								P50 = 15% P75 = 22%
Director of People & Safety (Total Cash)	17									

* Data for previous incumbent as role is currently vacant.

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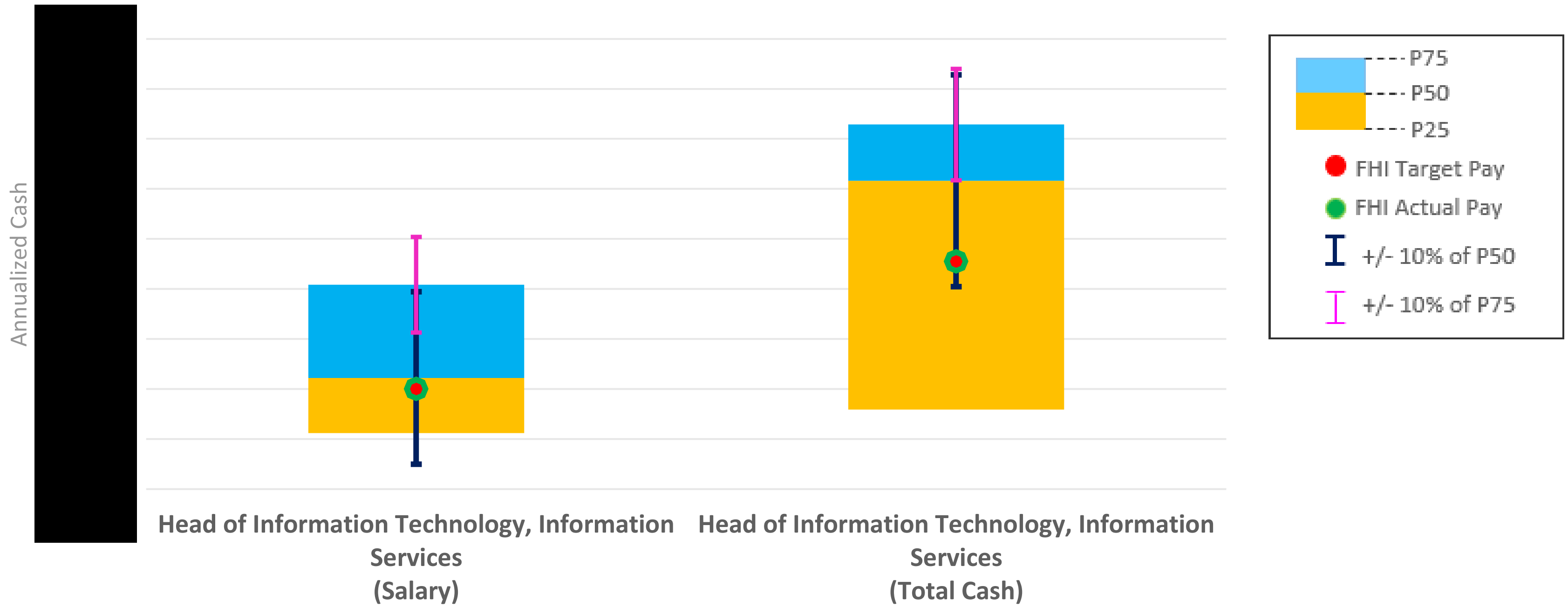
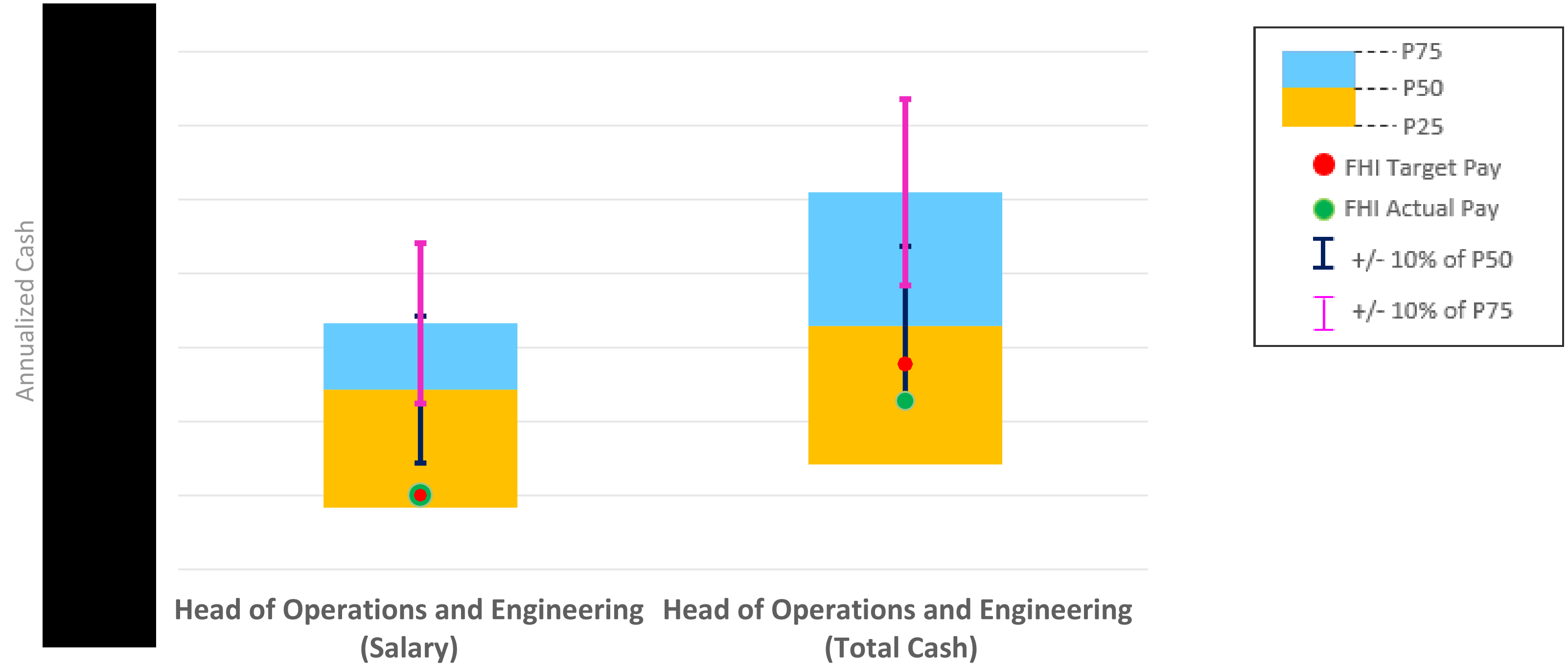
VP of Information Technology



Internal Position	# of Incumbents	FHI Actual Pay	FHI Design Pay (Job Rate)	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
VP of Information Technology (Salary)	13	[redacted]								P50 = 18% P75 = 23%
VP of Information Technology (Total Cash)	13									

VP of Engineering and Operations



Internal Position	# of Incumbents	FHI Actual Pay	FHI Design Pay (Midpoint)	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
VP of Engineering and Operations (Salary)	22	[redacted]								P50 = 15% P75 = 23%
VP of Engineering and Operations (Total Cash)	22									

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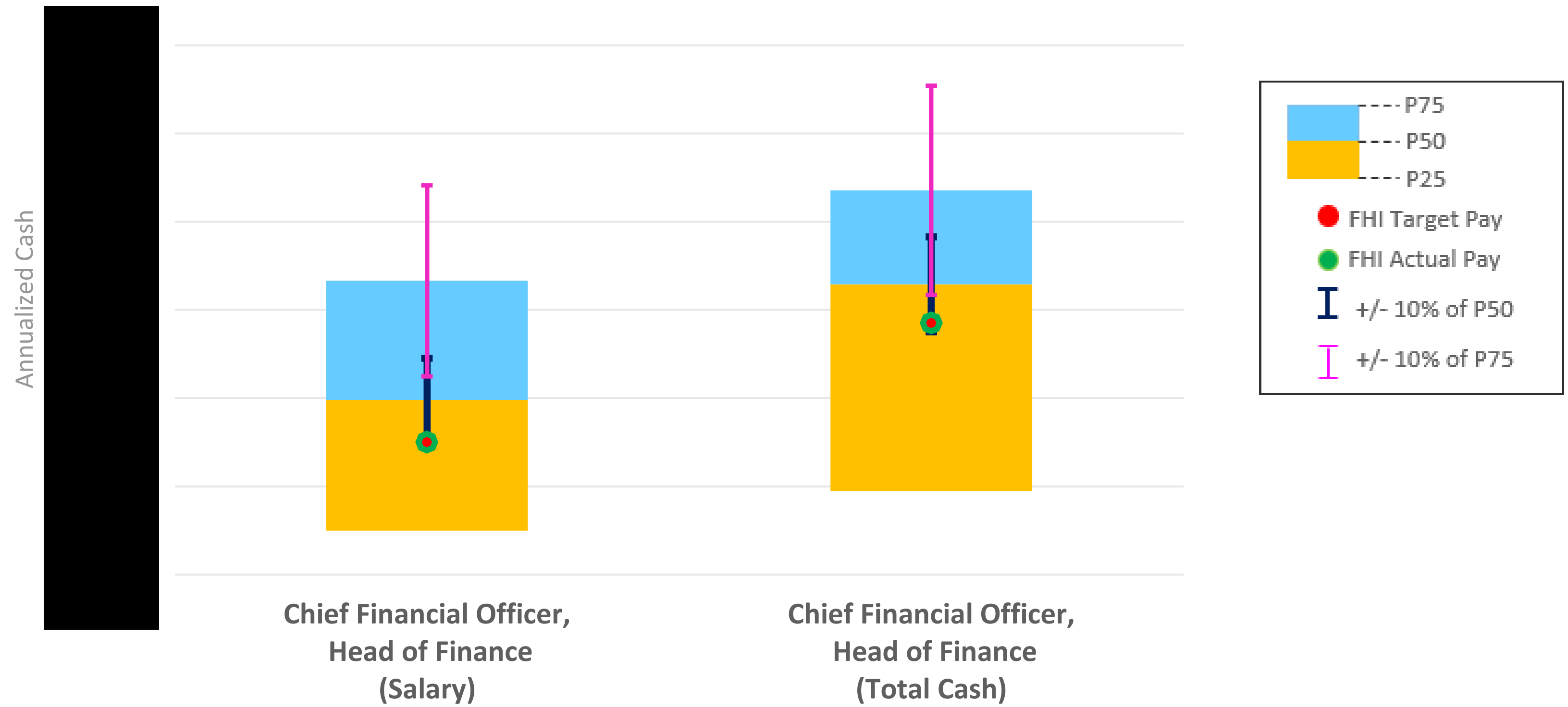
Chief Financial Officer



Internal Position	# of Incumbents	FHI Actual Pay	FHI Design Pay (Midpoint)	Market Rate P50	Actual Pay vs. Market P50	Market Rate P75	Actual Pay vs. Market P75	Design Pay vs. Market P50	Design Pay vs. Market P75	Market Target Bonus
Chief Financial Officer (Salary)	32	[redacted]								P50 = 15.5% P75 = 22%
Chief Financial Officer (Total Cash)	32									

Summary of Market Positioning

- The following table summarizes Festival Hydro's midpoints/job rates and design total cash (midpoint + target bonus) relative to both market P50 and market P75
  - Overall, the executive positions within Festival Hydro are behind market on salary, and slightly further behind market when considering total cash

Executive Position	FHI Midpoint Compared to Market P50	FHI Midpoint Compared to Market P75	FHI Total Cash Compared to Market P50	FHI Total Cash Compared to Market P75
Director of People & Safety	[redacted]			
VP of Information Technology				
VP of Engineering & Operations				
Chief Financial Officer				

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Design Considerations

1) Confirm compensation strategy around market positioning
   - Midpoint of salary ranges to be calibrated to P50 of the LDC market
     - Pay strategy should align with organizational performance strategy
   - Continue having two salary ranges for VP-level jobs
   - Top of the salary range will be higher than P75 for exceptional performance

2) Adopt an approach for periodic increases to Executive salary ranges
   - Range design provides flexibility for increases (or not) rather than discrete steps with annual increases, other than cost-of-living increases
   - Ranges do not necessarily need to increase every year by an annual cost-of-living adjustment as there is room within the salary range to provide these annual increases, along with any performance-based increases, if applicable

3) Consider having bonus payouts above target (1x bonus target percent) for overachievement on <u>all</u> goals and objectives, both organizational and individual
   - Potential to earn a bonus payout above target can serve as an additional motivating influence for some senior leaders
   - Paying out above target for exceptional performance in a given year supports compensating an Executive above market P50 for above market performance

4) In conjunction with (3), consider lowering threshold bonus payout levels to 0.5x target to be closer to market prevalent practice and to facilitate funding for others’ overachievement and corresponding payout above target

Recommendations

Director of People and Safety

- Increase the job rate by [redacted] to maintain market positioning around the [redacted] for the Head of HR benchmark job
  - Targeting pay around the [redacted] based on the actual content of the People and Safety portfolio within Festival Hydro versus what is typically expected of the Head of HR role in the external LDC market
  - The proposed job rate is consistent with the salary at the [redacted] for the Manager of HR benchmark job

Step 1 (80%)	Step 2 (84%)	Step 3 (88%)	Step 4 (92%)	Step 5 (96%)	Job Rate (100%)
[redacted]					

VP Recommendations - Salary

- Increase the target job rate (range midpoint) of the executive salary ranges to maintain market-competitive levels on base salary
- Additionally, LBCG recommends maintaining the current target bonus amount of 15% of base salary as it is consistent with market-competitive target levels and results in competitive total cash opportunities
    - Continue having effective and consistent performance management discussions, including objective setting, performance measures, and clear communication and understanding for how performance is assessed and its impact on pay

Current Ranges

Executive Position	Minimum (80%)	FHI Job Rate (100%)	Maximum (120%)
VP of Information Technology	[redacted]	[redacted]	[redacted]
CFO VP of Engineering & Operations	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

Proposed Ranges

Executive Position	Minimum (80%)	FHI Job Rate (100%)	Maximum (120%)
VP of Information Technology	[redacted]	[redacted] ~ P50	[redacted]
CFO VP of Engineering & Operations	[redacted]	[redacted] ~ P50	[redacted]

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Proposed Total Cash Ranges

VP I – Salary	Range Minimum (80%)	Range Midpoint (100%)	Range Maximum (120%)
VP of IT	[redacted]		

Above P75

VP I – Total Cash (with 15% bonus)	Range Minimum (80%)	Range Midpoint (100%)	Range Maximum (120%)
VP of IT	[redacted]		

Above P75

VP II – Salary	Range Minimum (80%)	Range Midpoint (100%)	Range Maximum (120%)
CFO VP of Eng & Ops	[redacted]		

Above P75

VP II – Total Cash (with 15% bonus)	Range Minimum (80%)	Range Midpoint (100%)	Range Maximum (120%)
CFO VP of Eng & Ops	[redacted]		

Above P75

Summary of Incremental Costs

- The total incremental cost for the recommended salary increases for these three executives, including benefits load applied only on base salary is [redacted].
    - Costs assume merit increases for the VP of Engineering & Operations and for the Chief Financial Officer incumbents
    - Costs also assume that performance targets will be met as bonus amounts are costed at target payout levels

Executive Position	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
VP of Information Technology	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
VP of Engineering & Operations	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
Chief Financial Officer	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
Change ($)	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

*Additional cost for benefits is only applied to base salary.

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Appendices

I. Costing by Position
II. Analysis Methodology
III. Survey Participant List
IV. 2021 Recommendations

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I(a) - VP of Information Technology

- Although this role has a new incumbent since August of 2023, the costs are based on a modest increase to the salary range midpoint/job rate and assumes that the new incumbent will receive a salary increase at some point during 2024
  - Bonus target to remain at 15% for consistency at the VP level
  - Incremental increase for this role is [redacted]

VP of IT	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
Current	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
Proposed	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
Change (%)	[redacted]	0%	[redacted]	[redacted]	[redacted]	[redacted]
Change ($)	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

*Additional cost for benefits is only applied to base salary.

I(b) - VP of Engineering and Operations

- Cost to move the incumbent VP of Engineering and Operations is based on increasing his salary to the proposed new salary range midpoint / job rate
- Midpoint is appropriate for experienced employees who have gained the necessary capabilities to perform at the job level, as well as demonstrating solid performance
  - Bonus target to remain at 15% for consistency at the VP level
  - Incremental increase for this role is [redacted]

VP of Engineering & Operations	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
Current	[redacted]	15%	[redacted]			
Proposed		15%				
Change (%)		0%				
Change ($)						

*Additional cost for benefits is only applied to base salary.

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I(c) - Chief Financial Officer

- Incumbent is a seasoned CFO who has demonstrated sustained high performance in all areas of accountability for both FHI and FHSI, as well as having oversight of all corporate projects
  - Salary should be positioned closer towards the maximum of the salary range
- Cost to move the incumbent CFO between the proposed new salary range midpoint and maximum is shown in the table below
  - Bonus target to remain at 15% for consistency at the VP level
  - Incremental increase for this role is [redacted]

CFO	Base Salary	Target Bonus (%)	Target Bonus ($)	Total Cash	Benefits Load (20%)*	Total Loaded Cost
Current	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
Proposed	[redacted]	15%	[redacted]	[redacted]	[redacted]	[redacted]
Change (%)	[redacted]	0%	[redacted]	[redacted]	[redacted]	[redacted]
Change ($)	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]

*Additional cost for benefits is only applied to base salary.

II - Analysis Methodology

- 2023 salaries were compared against secondary market data[1] provided by Festival Hydro Inc.
- Market salaries were aged to reflect market movement anticipated for 2024
- Market data were analyzed with commonly-used compensation statistical reporting
  - 25th percentile
  - 50th percentile – "median" of the market pay or "Market Rate"
  - 75th percentile
- Incumbent annual salary and 2023 job rate (midpoint) were compared with the "Market Rate", as well as with the market 75th percentile
- Target bonus, as a percentage of based salary, was compared to the market target incentive
- Incumbent annual salary + target bonus was also assessed against the market actual total cash (salary + bonus paid) for comparator LDCs
- Compensation is considered market-competitive if pay is within:
  - +/- 10% of Market for senior jobs

[1]The MEARIE Group's 2023 Management Salary Survey of Local Distribution Companies (see Appendix for participating LDCs).

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III - MEARIE Survey Participant List

2023 Management Salary Survey of Local Distribution Companies

Alectra Utilities Inc.	Kingston Hydro
Bluewater Power Distribution	Lakeland Power Distribution Ltd.
Burlington Hydro Inc.	London Hydro Inc.
Centre Wellington Hydro Ltd.	Milton Hydro Distribution Inc.
E.L.K. Energy Inc.	Newmarket-Tay Power Distribution Ltd.
Elexicon Energy Inc.	Niagara Peninsula Energy Inc.
Enova Power Corp.	North Bay Hydro Distribution Limited
Entegrus Powerlines Inc.	Northern Ontario Wires Inc.
ENWIN Utilities Ltd.	Orangeville Hydro Limited
EPCOR Electricity Distribution Ontario Inc.	Oshawa PUC Networks Inc.
ERTH Power Corporation	Ottawa River Power Corporation
Essex Powerlines	Peterborough Utilities Group
Festival Hydro Inc.	PUC Services Inc.
Fort Frances Power Corporation	Rideau St. Lawrence Distribution
GrandBridge Energy Inc.	Sioux Lookout Hydro Inc.
Greater Sudbury Utilities	Synergy North
Grimsby Power Inc.	Wasaga Distribution Inc.
Halton Hills Hydro Inc.	Welland Hydro-Electric System Corp.
InnPower Corporation	

Recommendation from 2021 Executive Compensation review.

Recommendations - Salary

- LBCG recommends increasing the target job rate (range midpoint) of the executive salary ranges to market-competitive levels on base salary
- Additionally, LBCG recommends implementing an incentive pay plan (bonus) to support the link between pay and performance, to reinforce leadership collaboration and to align with market practice
  - A critical precursor for merit-based pay, both salary and incentive pay, is to have effective and consistent performance management, including objective setting, performance measures, and clear communication and understanding for how performance is assessed and its impact on pay

Current Ranges

Executive Position	Minimum Salary (81%)	FHI Job Rate (100%)	Maximum Salary (118%)
CFO VP of Engineering & Operations	[redacted]		
VP of Information & Technology			

Proposed Ranges

Executive Position	Minimum Salary (80%)	FHI Job Rate (100%)	Maximum Salary (120%)
CFO VP of Engineering & Operations	[redacted]		
VP of Information & Technology			

Recommendation from 2021 Executive Compensation review.

Recommendations - Bonus

- LBCG recommends adding an incentive pay plan bonus opportunity for members of the senior leadership team (VPs and HR), in addition to increasing salaries
  - In the LDC market, bonus is typically offered to senior leadership roles
  - Given that Festival Hydro is actively recruiting for two VP roles, there is a risk of not being able to attract top tier candidates who are expecting bonus to be a market-competitive component of the executive compensation offering

CFO and VP of Engineering & Operations

Current Job Rate	Proposed New Job Rate	Target Bonus (%)	Target Bonus ($)	Target Total Cash ($)
[redacted]	[redacted]	20%	[redacted]	[redacted]
[redacted]	[redacted]	15%	[redacted]	[redacted]
[redacted]	[redacted]	10%	[redacted]	[redacted]

Market P50

VP of Information & Technology

Current Job Rate	Proposed New Job Rate	Target Bonus (%)	Target Bonus ($)	Target Total Cash ($)
[redacted]	[redacted]	20%	[redacted]	[redacted]
[redacted]	[redacted]	15%	[redacted]	[redacted]
[redacted]	[redacted]	10%	[redacted]	[redacted]

~ Market P50

Thank you!

LBCG

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Attachment 3

4-Staff-21 – 2023 Mearie Management Survey

The MEARIE Group

2023 Management Salary Survey of Local Distribution Companies

September 2023

Survey Administrators: Eckler Ltd.
Confidential and Proprietary

Contents

Introduction

The MEARIE Group is pleased to present this report of the 2023 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, Local Distribution Companies (LDCs) are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. High inflation and changing workplaces in response to the COVID-19 pandemic have also further impacted compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's LDCs to assist you and in understanding the competitive landscape and support your efforts in developing pay practices that attract, motivate, and retain high quality, high performing employees.

The survey was administered in 2023 in partnership with Eckler Ltd., who are experts in developing and managing salary surveys across all sectors of the economy. There were no significant changes to the survey for 2023. The survey was launched in May 2023 and 37 organizations provided completed survey materials to inform this report. The report is divided into two parts:

Part 1 – Study Report (this document)

- Profile of survey participants
- Overview of salary projections for 2024 salary planning, and other market trends and programs
- Information on benefits programs and offerings
- Summary of the survey methodology and definitions of terms
- Job descriptions for the 56 benchmark jobs

Part 2 – Benchmark Job Tables (provided as a separate Excel file)

- Reporting based on number of customers, number of employees, region, and revenue
- Reporting up to total cash compensation, including annual incentive or variable pay information

Confidentiality Policy

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey and the Survey on Board of Director Compensation (each, a "Survey"), as well as the Survey Administrator and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC's data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g., by geography or size).

All of the information obtained through this Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither the Survey Administrator nor The MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or the Survey Administrator or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey will also be included in the Survey Administrator's compensation database. Information in the Survey Administrator's database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of a Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests, or will co-operate with respect to any steps The MEARIE Group and/or Survey Administrator reasonably wishes to take, to contest or limit the scope of the disclosure.

The MEARIE Group will not be liable for breaches by participating LDCs or the Survey Administrator of this Confidentiality Policy.

Survey Overview

Benchmark Positions

This survey covers 56 benchmark jobs that are representative of the functions within The MEARIE Group's member organizations. No changes were made to the benchmark jobs in 2023. The job descriptions for each benchmark are provided in **Appendix C.**

Job Family	Job Code	Job Title
Executives	0000	President & Chief Executive Officer
Executives	0001	Chief Operating Officer
Executives	0002	Head of Operations and/or Engineering
Executives	0003	Chief Financial Officer / Head of Finance
Executives	0004	Head of Customer Service
Executives	0005	Head of Regulatory Affairs
Executives	0006	Head of Human Resources
Executives	0007	Head of Information Technology / Information Services
Administration	1000	Executive Assistant
Administration	1001	Administrative Assistant
Engineering	2000	Director, Engineering
Engineering	2001	Engineering Manager / Distribution Engineer
Engineering	2002	Project Engineer
Engineering	2003	Supervisor, Engineering
Operations	2500	Director, Operations
Operations	2501	Manager, Operations
Operations	2502	Manager, Control Centre
Operations	2503	Supervisor, Control Centre
Operations	2504	Supervisor, Protection and Control
Operations	2505	Supervisor, Station Maintenance
Operations	2506	Line Supervisor
Operations	2507	Manager, Meter Department
Operations	2508	Supervisor, Meter Department
Operations	2509	Manager, Continuous Improvement
Supply Chain / Procurement	3000	Director, Supply Chain Management

Supply Chain / Procurement	3001	Manager, Procurement and/or Inventory and/or Facilities and/or Fleet
Supply Chain / Procurement	3002	Supervisor, Stores/Inventory/Warehouse
Accounting/Finance	4000	Controller / Director, Finance
Accounting/Finance	4001	Manager, Accounting
Accounting/Finance	4002	Manager, Risk Management
Accounting/Finance	4003	Supervisor Accounting
Accounting/Finance	4004	Financial or Business Analyst
Accounting/Finance	4005	Accountant
Customer Service	5000	Director, Customer Service
Customer Service	5001	Manager, Customer Service and/or Billing
Customer Service	5002	Supervisor, Customer Service and/or Billing and/or Collections
Customer Service	5003	Key Account Specialist
Communications	5500	Director, Communications
Communications	5501	Manager, Communications
Communications	5502	Communications Specialist
Regulatory Affairs	6000	Director, Regulatory Affairs
Regulatory Affairs	6001	Manager, Regulatory Affairs
Regulatory Affairs	6002	Regulatory Accountant
Conservation/Demand	7000	Settlement or Rate Analyst
Information Systems/Technology	8000	Director, Information Systems
Information Systems/Technology	8001	Manager, Information Systems
Information Systems/Technology	8002	Systems and/or Program Administrator / Applications and/or Systems Support Professional
Information Systems/Technology	8003	Manager Information Security
Information Systems/Technology	8004	Network Specialist/Manager/Engineer
Human Resources	9000	Human Resources Manager
Human Resources	9001	Human Resources Generalist
Human Resources	9002	Human Resources Coordinator

Human Resources	9003	Payroll
Human Resources	9004	Manager, Health & Safety
Non-Regulated Business - Business Development Roles	N001	Executive Role - Non-Regulated Business
Non-Regulated Business - Business Development Roles	N002	Non-Executive Role - Non-Regulated Business

List of Participants

All Ontario LDC MEARIE members were invited to participate in the survey, and 37 organizations submitted completed survey materials:

Alectra Utilities Inc

Bluewater Power Distribution

Burlington Hydro Inc

Centre Wellington Hydro Ltd

E.L.K. Energy Inc

Elexicon Energy Inc

Enova Power Corp

Entegrus Inc

ENWIN Utilities Ltd

EPCOR Electricity Distribution Ontario Inc

ERTH Power Corporation

Essex Powerlines

Festival Hydro Inc

Fort Frances Power Corporation

GrandBridge Energy

Greater Sudbury Utilities

Grimsby Power Inc

Halton Hills Hydro Inc

InnPower Corporation

Kingston Hydro

Lakeland Power Distribution Ltd

London Hydro Inc

Milton Hydro Distribution Inc

Newmarket-Tay Power Distribution Limited

Niagara Peninsula Energy Inc

North Bay Hydro Distribution Limited

Northern Ontario Wires Inc

Orangeville Hydro Limited

Oshawa PUC Networks Inc

Ottawa River Power Corporation

Peterborough Utilities Group

PUC Services Inc

Rideau St. Lawrence Distribution

Sioux Lookout Hydro Inc

Synergy North

Wasaga Distribution Inc

Welland Hydro-Electric System Corp

Participant Profile

The profile of the 37 participants is summarized in the tables below. The figures are reported as provided by the participants and have not been verified.

LDC Profile (N = 37)	P25	P50	P75	Average[1]
Operating Budget, excluding cost of energy (millions)	$6.8	$14.2	$28.3	$37.6
Operating Budget, including cost of energy (millions)	$35.6	$85.6	$177.9	$254.8
Number of Employees (full-time equivalent)	25.0	55.0	122.0	120.5
Number of Union Employees (full-time equivalent)	12.0	36.0	83.0	68.0
Number of Non-Union Employees (full-time equivalent)	10.0	24.0	41.0	52.5
Number of Customers	14,423	28,324	58,421	72,171
Gross Revenue, including cost of energy (millions)	$37.2	$87.7	$191.3	$263.8
Gross Revenue, excluding cost of energy (millions)	$8.8	$19.6	$38.2	$55.5
Regulated Gross Revenue[2]	97.0%	98.6%	99.0%	96.3%
Unregulated Gross Revenue[2]	1.0%	1.4%	3.0%	3.7%

1. Where averages are significantly higher than the median (or P75) of the market, this indicates a small number of observations with a large number which skew the average data high.
2. Twenty-five (25) of the 37 participants indicated there is a split between regulated and unregulated gross revenue; the data provided for this statistic is only the organizations indicating the split. Twelve organizations are not reporting blended revenue.

All organizations that responded reported that their fiscal year end is December.

Participants were also asked to report any sister company revenue and number of employees information, if applicable. Overall, 16 organizations reported some revenue from sister companies. Where organizations did not have direct employees generating the revenue, this was due to administration of non-employee contractors, or, overseeing other staff not within the LDC and revenue sharing arrangements.

Sister Profile (N = 16)	P25	P50	P75	Average
Total Revenue (millions)	$0.3	$1.8	$13.7	$10.5
Number of Employees (full-time equivalent)	0.0	4.3	29.0	30.0

Salary Administration

Salary Adjustments

Compensation ranges, also known as salary frameworks or salary structures, are the guidelines by which companies administer compensation. These frameworks may be single job rates, step rate systems, salary ranges, or broad bands. Typically, compensation ranges are adjusted based on economic factors on a regular basis (annually). Actual compensation, or salaries paid, is the actual amount paid to employees within the role. The actual compensation of an incumbent is typically within the salary range and their position in the range/steps varies with tenure, experience and often, performance.

Organizations were asked how they adjusted salary ranges and actual salaries in 2022 and 2023, what they are forecasting for 2024.

Salary Range Adjustments

The most common month of salary range adjustments is January, followed by April. The below table shows the average salary range adjustments, excluding zeros. Survey participants are planning to increase salary ranges in 2024 by an average of 2.98%.

Year	CEO	Executive	Director	Management	Professional/ Technical	Admin	Overall
2022 (N=35)	3.86%	3.62%	3.50%	3.00%	3.05%	3.00%	3.35%
2023 (N=30)	3.53%	3.24%	3.19%	3.05%	3.14%	3.08%	3.20%
2024 (N=13)	3.27%	3.27%	3.00%	2.77%	2.77%	2.77%	2.98%

The salary range adjustment predictions have trended below what is implemented in the coming year. Given higher and sustained inflation than forecasts indicated, organizations adjusted at a higher percentage. Eckler's 2022 Salary Forecast survey also indicated that close to one-third of organizations also made a mid-year adjustment to ranges in addition to annual adjustment to attempt to maintain market position and mitigate talent loss. Historically organizations have adjusted ranges annually, or even less periodically (i.e., every 2 or 3 years with market review).

Actual Salary Increases

The most common month of actual salary increases is January, followed by April. The below table shows the average actual salary increases, excluding zeros. Survey participants are planning to increase salaries in 2024 by an average of 3.19%.

Year	CEO	Executive	Director	Management	Professional/ Technical	Admin	Overall
2022 (N=35)	2.87%	3.04%	3.05%	3.11%	3.04%	2.98%	3.07%
2023 (N=32)	3.66%	3.67%	3.63%	3.51%	3.49%	3.39%	3.57%
2024 (N=14)	2.98%	3.33%	3.22%	3.18%	3.12%	3.10%	3.19%

Similar to salary range movement, actual salary increases in 2022/2023 are higher than the predicted values in 2021/2022.

Incentive Programs

Performance Factors

For organizations that have a broad-based annual incentive plan in place, participants were asked to provide the weighting of factors that are used to determine actual bonus payouts. The below table reports the average weighting of each performance metric, by employee category. Executives and Senior Management are typically more heavily weighted toward corporate performance, while Middle Management, Professional, and Administrative jobs are typically more heavily weighted toward individual performance. Team/Department factors are not commonly used, with only five participants reporting a weighting for Team/Department performance.

Performance Factor	CEO (N=24)	Executive (N=22)	Director (N=18)	Management (N=20)	Professional/ Technical (N=15)	Admin (N=17)
Corporate	67.9%	55.9%	50.5%	40.8%	30.9%	37.5%
Individual	28.7%	36.3%	45.4%	49.4%	64.9%	60.6%
Team/ Department	2.4%	6.7%	4.1%	8.5%	4.3%	1.9%

The most common plan for management roles is 50% equal weighting between corporate and individual performance, and the most common plan for professional/technical and administrative staff is 100% individual performance.

Incentive Opportunity Range

Target-based incentive programs typically have a minimum level of performance that must be achieved to receive an incentive payout. If that threshold level of performance is not achieved, then there is no payout. Conversely, target-based incentive programs typically also have a maximum level of payout, where regardless of how much an employee exceeds their performance targets, the payout will not be any higher than the maximum. Between the payout at threshold performance and the maximum payout, incentive plans typically increase the level of payout as the performance levels also increase.

For example, if a job has an incentive target of 20% of base salary and the payout at the threshold level of performance is half of the target, then the threshold level of performance is achieved, the payout will be 10% of base salary. If the maximum incentive is 2X the target, then the payout will be capped at 40% of base salary.

The below table reports the average maximum incentive and average incentive at the threshold level of performance, as a multiple of target, by employee category. The typical maximum payout is 1X target, and the typical payout at the threshold level of performance is 0.5X target. In the broader market, it is more common to see higher maximum bonus levels as a multiple of target, especially at the Senior Management and Executive levels.

Incentive Payout Range	**CEO** (N=20)	**Executive** (N=19)	**Director** (N=19)	**Management** (N=18)	**Professional/ Technical** (N=15)	**Admin** (N=16)
Maximum Payout	1.40X	1.39X	1.31X	1.33X	1.29X	1.35X
Payout at Threshold Level of Performance	0.55X	0.54X	0.52X	0.56X	0.47X	0.50X

Compression Policies

Participants were asked if they have a formal salary compression program in place. Only 8% of participants (N=37) reported that they do have a formal program. Jobs affected include Line Supervisor and Operations Manager.

Line Supervisors

The direct supervisor of unionized staff is typically called the “Line Supervisor”. Most organizations (60%) (21 of 35 respondents) reported that Line Supervisors receive overtime compensation. The organizations that do not offer overtime to Line Supervisors typically do offer other compensation, most commonly time in lieu, but may also be a bonus or on call premiums.

The below table reports the average annual amount of overtime paid to the Line Supervisors and average union staff incumbent reporting to the Line Supervisor; 11 organizations were able to provide average annual overtime dollar amounts.

Position (N=11)	**P25**	**P50**	**P75**	**Average**
Line Supervisor	$7,350	$15,000	$23,500	$16,357
Union Staff	$10,250	$14,000	$18,966	$18,272

Both the Line Supervisor (N=21) and the union staff (N=25) roles typically have an overtime and/or on call compensation rate of 2X regular base salary.

Participants were asked if any additional staff other than front-line supervisor roles are eligible for overtime. Out of the 22 organizations that responded, 50% do offer overtime to other roles. Typically, only roles below the Supervisor or Manager level are eligible for overtime.

The below table shows the team sizes for field teams, i.e., the number of union roles per supervisor.

Team Size (N=33)	**P25**	**P50**	**P75**	**Average**
Union Roles per Supervisor	7	9	11	9

72% of LDCs (26 of 36 respondents) indicated that a company owned or leased car is provided to supervisors for work purposes.

- 23 organizations provided information about car storage. 74% of these organizations indicated that company cars can be stored at the employee's home and 26% indicated that company cars are stored at their work location.

- 25 organizations provided information about personal use of company cars. 64% of these organizations allow some level of personal use of company cars.

    - Of these 16 organizations, 81% have a mileage tracking system in place for personal use of company cars. The most common method used to track mileage of personal use of company cars is a logbook.

    - 14 organizations provided details on limitations of personal use of company cars. 43% indicated that employees can use company cars for personal use with no limitations, 29% indicated that employees can use company cars for commuting only, 14% indicated that employees can use company cars for personal use within reason, 7% indicated the employees can use company cars for personal use by exception only, and 7% indicated that only the employee can drive the company car.

- Seven organizations provided taxable benefit amounts for company cars. The median amount reported was $5,500.00, and the average amount reported was $8,081.14.

Non-Regulated Operations

Some participants in this survey earn additional revenue via non-regulated revenue channels. This section discusses the details of these non-regulated operations.

Non-Regulated Revenue

32% of organizations (N=37) indicated that they do not have any non-regulated revenue, 38% of organizations indicated that the non-regulated revenue is structured as a separate company, and 30% indicated that non-regulated revenue is embedded within the organization.

Of the organizations that have some non-regulated revenue, 20 provided details around the non-regulated revenue is supported.

Non-Regulated Revenue	Yes	No
Full time dedicated sales staff	30%	70%
Full time dedicated non-sales staff	45%	55%
Regulated company provides corporate services for a fee	75%	25%
Shared staffing arrangement with regulated company	70%	30%

Key Performance Indicators

Participants that have non-regulated sources of income were asked what the Key Performance Indicators (KPIs) for the business are, as well as proportion of each used in incentive and/or performance measurement. The below table summarizes the prevalence and average scorecard weighting of each KPI.

Key Performance Indicator	KPI Used (% Yes) (N=13)	Average Scorecard Weighting[1] (N=7)
Earnings / Net Income	62%	42.7%
Other Financial Metric	54%	36.9%
Innovation: New Product / Service Offering / Development	31%	*
Customer: Retention/New	15%	*
Other	46%	30.0%

**Insufficient data to report*

1. Average scorecard weighting is based upon organizations only where the KPI = Yes.

Of the organizations that responded "other", common descriptions were health and safety, system reliability, and individual goals.

Of the eleven organizations provided information, 45% of organizations are seeking to grow their non-regulated business 10-20% in the next three years, 36% are looking to maintain, 9% are seeking to grow 5-10%, and 9% are seeking to grow 30%.

Engineer Compensation

Many organizations (43%, N=35) differentiate compensation for engineers-in-training / P.Eng candidates. Generally, engineers can expect a pay increase once they have achieved the designation. Most commonly, engineers-in-training are paid on different salary grids/ranges than engineers with their P.Eng designation, so once the designation is achieved, the engineer moves to the licensed engineer grid/range, which is higher than the engineer-in-training grid/range. In some other cases, engineers-in-training and licensed engineers are on the same pay band, however engineers-in-training cannot achieve full job rate until they have achieved the P.Eng designation.

COVID-19 Strategies

COVID-19 Impact

Participants were asked if COVID-19 impacted different aspects of their salary administration programs.

- 5% of organizations (N=37) reported that salary range and/or actual salary increases were affected by COVID-19.
- No organizations (N=37) reported that promotions and/or salary increases were delayed due to COVID-19.
- 5% of organizations (N=37) reported that merit increase budgets were higher or lower due to COVID-19 (though this is also due to broader economic pressure beyond COVID-19).
- 7% of organizations (N=30) reported that adjustments were made mid-year to short-term variable pay programs due to COVID-19.
- 7% of organizations (N=28) reported that incentive programs were affected by COVID-19, for example adjusting key performance indicators.
- 3% of organizations (N=37) reported that pay premiums were adopted for front-line roles due to COVID-19.

COVID-19 Strategies

Organizations were asked what strategies were utilized to combat the labour challenges faced since the onset of the COVID-19 pandemic, and, if those strategies were temporary measures or have become continuous measures. The prevalence of "yes" responses overall is reported below.

Tactic (N=36)	Tactic Used: % Yes	Temporary Measure %	Continuous Measure %
Increase or introduction of employee wellness allowances	11%	0%	100%
Optional leave	8%	100%	0%
Stipends, home allowances, or other compensation allowances	8%	67%	33%

Increased benefits, including expanded EAP coverage	8%	0%	100%
Early retirement provision	6%	*	*
Permanent position eliminations/ terminations	6%	*	*
Bonus / discretionary compensation reduction	6%	*	*
Pay premiums / hazard pay	6%	*	*
Retention awards	6%	*	*
Introduction of new benefits	6%	*	*
Temporary layoffs / furloughs	3%	*	*
Spot / recognition bonuses	3%	*	*
Base salary freeze	0%	*	*
Temporary pay reduction with no hours/duties adjustment	0%	*	*
Temporary pay reduction with hours/duties also reduced	0%	*	*
Work-sharing program	0%	*	*
Amendments to car allowances	0%	*	*

**Insufficient data to report*

Details are provided for the following commonly used tactics:

- The most utilized tactic was increasing or introducing employee wellness allowances, which is a measure that continues to be in place for all organizations that offer it. Organizations increased the value of their wellness benefits and added at-home exercise equipment to their employee purchase plan program. This combined with increased benefits, including expanded EAP coverage and increased values of health care spending accounts indicate a higher concentration on employee health and wellness and building that into total rewards.

- Optional leave was temporarily offered, where employees were unable to find childcare / dependent care and could not work from home, or where employees exhausted vacation time.

- Stipends, home allowances, and other compensation allowances were typically offered on a temporary basis. For example, employees were allowed to claim workspace items through existing allowance accounts.

Remote Work

Participants were asked to provide details on their remote work policies. All respondents (N=27) indicated that they have not, nor will they be changing compensation policies for remote roles versus office-based roles.

Four organizations indicated that there are no remote employees, and all employees are in the office five days a week. Two organizations have no minimum in-office requirement and 11 organizations indicated that have a hybrid model:

- 13 organizations require employees to be in the office on occasion or on an ad-hoc basis, depending on meetings and events happening.

- Three organizations require employees to be in the office two days a week.

- Four organizations require employees to be in the office three days a week.

- Two organizations require employees to be in the office four days a week.

- One organization's hybrid model varies depending on the department.

Three organizations indicated that there are no limits to where an employee resides. Most organizations (N=26) do have a policy about employee geography limitations where:

- 12 organizations require employees to be able to meet in-office day requirements or be close to service their service territory.

- Four organizations require employees to be located in Ontario, and one additional organization indicated a preference for employees to be located in Ontario.

- Two organizations require employees to be in Canada.

- Two organization require employees to be within reasonable commute of their office / in the municipality.

Employee Engagement

Participants were asked to provide details on their employee engagement strategies. Common measures employed to keep employees engaged included:

- Increased communications reported by 11 organizations, including online check-ins, team meetings, and town halls.
- Virtual company lunches and other events, or in-person if restrictions allowed reported by six organizations.
- Wellness programs/initiatives and/or awareness training reported by four organizations.
- Employee recognition initiatives reported by four organizations.

30% of organizations (N=33) experienced higher than usual voluntary turnover during the COVID-19 pandemic. Accommodations that HR made to retain employees that were subject to added pressures due to the pandemic included:

- Work from home allowances reported by 13 organizations.
- Flexible/modified work schedules reported by eight organizations.
- Unpaid leave where work from home was not possible was reported by four organizations.
- Enhanced sick leave provisions to cover COVID-related absences were reported by two organizations.

Five organizations indicated that no formal accommodations were made.

Benefits Policies

Company Cars

Company-Owned Cars and Car Allowances

Where organizations provide a car allowance or company car as a perquisite (i.e., not cars provided for business use only), they are most commonly offered as a monthly allowance. The below table shows the monthly allowance amounts reported, by employee category.

Monthly Car Allowance	P25	P50	P75	Average
CEO (N=16)	$692	$850	$1,000	$1,076
Executive (N=13)	$584	$750	$750	$715
Director (N=5)	*	$450	*	$430
Management (N=1)	*	*	*	*

**Insufficient data to report*

Monthly leases are also offered to CEOs by three organizations. The average monthly lease reported was $1,072. Two organizations provide the CEO with a company owned car.

Reimbursement Rates

The below table shows the reimbursement rates reported for using a personal automobile for business purposes. The typical rate is 68 cents per kilometer, reported by 20 organizations and is aligned with the Canada Revenue Agency mileage rate for 2023.

Mileage (N=37)	P25	P50	P75	Average
Reimbursement Rate ($/km)	$0.61	$0.68	$0.68	$0.64

Participants were also asked to provide details regarding reimbursement for travel, meals, or other allowance coverage. Common themes identified are:

- 16 organizations provided information on meal allowances. The average daily meal allowance reported was $81.35 (N=12). Two organizations reported that meals are reimbursed based on the actual costs incurred, excluding alcohol.

- 11 organizations reported that employees must submit an expense reimbursement form and provide receipts.

- Six organizations reported that hotel and ground transportation expenses are reimbursed based on the actual costs incurred.

- Three organizations reported that they pay for highway tolls and parking, in addition to their mileage reimbursement policy.

Perquisites

Additional Benefit Level

Participants were asked to provide the basic and supplemental life insurance coverage offered to senior management, where the organization pays the premium. Generally, more organizations are providing a higher level of life insurance coverage to senior level roles.

Employee Level	Basic Coverage	Supplemental Coverage
CEO	1.5X N=17	2 – 3X N=9
Executive	1.5X N=16	2 – 3X N=9
Director	1.5X N=13	2X N=8
Management	1.5X N=13	2X N=7

Education Reimbursement

24 organizations reported having a policy for post graduate programs. Common themes in the details of these plans included:

- Six organizations report that the program must be beneficial and add value to the organization.
- Three organizations reported that employees must be pre-approved for post graduate education programs.
- Three organizations reported that their post graduate programs policy covers all employees, while one organization reported that it is only offered to management and executives.

23 organizations provided information on the qualification criteria in their policy for post graduate programs:

- Nine organizations reported that the post graduate program must be a job requirement and/or beneficial for the employee's current or future position.
- Seven organizations reported that post graduate program must be pre-approved.
- Seven organizations reported that the policy applies to all permanent employes that have completed their probationary period.
- Three organizations reported that to be eligible, the employee must be a high performer or noted as a potential leader.

Five organizations reported that there is no maximum amount that will be reimbursed for post graduate programs. Twelve organizations reported specific annual maximum reimbursement amounts.

Education Reimbursement (N=12)	**P25**	**P50**	**P75**	**Average**
Annual Maximum	$1,875	$2,500	$10,000	$6,083

24 organizations provided information on any conditions of the subsidy for the employee to repay all or part of the subsidy if they leave the company within a specified time period:

- Five organizations reported that there is no formal policy in place.
- Eight organizations reported that their repayment policy requires different percentages of repayment based on years of service.
- Where the policy has a flat pay back percentage, it is most commonly either 50% or 100% of the amount reimbursed.

Club Membership – Fitness/Wellness

The below table reports the annual value of fitness/wellness club membership fees per employee, by employee category.

Employee Category	P25	P50	P75	Average
CEO (N=19)	$200	$300	$400	$382
Executive (N=19)	$200	$300	$400	$317
Director (N=19)	$190	$300	$400	$304
Management (N=19)	$200	$300	$400	$302
Professional/ Technical (N=17)	$200	$300	$400	$296

Health Care Spending Account

The below table reports the annual value of health care spending accounts per employee, by employee category.

Employee Category	P25	P50	P75	Average
CEO (N=13)	$680	$1,700	$2,000	$1,625
Executive (N=13)	$565	$1,600	$2,000	$1,393
Director (N=12)	$500	$725	$1,263	$1,054
Management (N=10)	$500	$725	$1,263	$960
Professional/ Technical (N=9)	$500	$700	$1,350	$952

Executive Medical Plan

The below table reports the annual value of executive medical plans per employee, by employee category.

Employee Category	P25	P50	P75	Average
CEO (N=8)	$1,150	$2,713	$3,125	$2,283
Executive (N=8)	$1,150	$2,713	$3,125	$2,283
Director (N=4)	*	$3,250	*	$2,809
Management (N=0)	*	*	*	*
Professional/ Technical (N=0)	*	*	*	*

**Insufficient data to report*

Personal Computer / Internet Connection for Home Use

The below table reports the annual value of personal computers and/or internet connection for home use per employee, by employee category.

Employee Category	P25	P50	P75	Average
CEO (N=4)	*	$1,100	*	$1,024
Executive (N=4)	*	$1,100	*	$1,032
Director (N=4)	*	$1,100	*	$1,032
Management (N=3)	*	*	*	$933
Professional/ Technical (N=3)	*	*	*	$933

**Insufficient data to report*

Other Perquisites

Participants were also asked about other perquisites that were not reported as commonly offered.

- Five organizations pay for employees' membership/professional dues. At the Management level, the average annual dues paid per employee is $1,100.00.
- Social club memberships are only offered by two organizations to the CEO and Executive levels, and only one organization to other employee levels.
- One organization offers second opinion medical advice to the CEO only.

Vacation

Vacation Entitlement – CEO

The below table reports the years of service required to be eligible for the number of vacation weeks indicated for CEOs.

CEO	2 Weeks (N=11)	3 Weeks (N=20)	4 Weeks (N=28)	5 Weeks (N=31)	6+ Weeks (N=35)
Average	Start	2	5	12	16
Median	Start	2	7	14	20
Most Common	Start	Start	Start	17	25

Vacation Entitlement – Executives

The below table reports the years of service required to be eligible for the number of vacation weeks indicated for Executives.

Executives	2 Weeks (N=9)	3 Weeks (N=18)	4 Weeks (N=27)	5 Weeks (N=29)	6+ Weeks (N=31)
Average	Start	1	5	12	17
Median	Start	1	6	14	20
Most Common	Start	Start	Start	17	25

Vacation Entitlement – Directors

The below table reports the years of service required to be eligible for the number of vacation weeks indicated for Directors.

Directors	2 Weeks (N=8)	3 Weeks (N=19)	4 Weeks (N=27)	5 Weeks (N=27)	6+ Weeks (N=28)
Average	Start	1	5	13	19
Median	Start	Start	6	15	21
Most Common	Start	Start	Start	15	25

Vacation Entitlement – Management

The below table reports the years of service required to be eligible for the number of vacation weeks indicated for Management.

Management	2 Weeks (N=13)	3 Weeks (N=33)	4 Weeks (N=36)	5 Weeks (N=36)	6+ Weeks (N=36)
Average	Start	1	6	13	20
Median	Start	Start	7	14	21
Most Common	Start	Start	9	15	25

Vacation Entitlement – Professional/Technical

The below table reports the years of service required to be eligible for the number of vacation weeks indicated for Professional/Technical roles.

Professional/ Technical	2 Weeks (N=16)	3 Weeks (N=30)	4 Weeks (N=32)	5 Weeks (N=32)	6+ Weeks (N=32)
Average	Start	2	7	15	22
Median	Start	2	8	15	24
Most Common	Start	Start	9	15	25

Unused Vacation

Participants were asked about their policy on annual vacation entitlement that is not fully utilized before the end of the year. All 37 survey participants responded to this question.

- 51% of organizations reported that a maximum amount of unused vacation can be carried over.
- 32% of organizations reported that unused vacation entitlement may be carried over, subject to a maximum total accumulated balance.
- 14% of organizations reported that all unused vacation entitlement may be carried over with no restrictions.
- 3% of organizations reported that unused vacation entitlement cannot be carried over to the next year.

Of the organizations that allow unused vacation entitlement to be carried over with restrictions, five organizations allow the full annual entitlement to be carried over. 24 organizations have a specified number of days in their carry over policy, which is most commonly five days, or eight days on average.

- 10 organizations have no time limits within outstanding vacation days must be used.
- 14 organizations require employees to use carried over vacation days within six months or less.
- 12 organizations require employees to use carried over vacation days within 12 months.

Participants were asked to provide details on any variations in vacation carry over policies by level or length of service:

- Six organizations reported that there are no variations by level or length of service.
- Three organizations reported that under special circumstances, the Board and/or President may approve an employee to carry over more than the regular carry over policy.
- One organization reported that under special circumstances, Management positions and above may be able to have unused vacation days paid out.
- One organization reported different numbers of days based on years of service, where the longer employees have been with the company, the more days they are entitled to carry over.

Benchmark Positions Survey Results

The benchmark job tables are provided as a separate Excel file. The file includes the statistical data for the survey benchmark jobs for up to total cash compensation, including annual incentive or variable pay information.

Reporting is available based on number of customers, number of employees, region, and revenue.

Market fluctuations can occur due to a variety of reasons, including true market movements, as well as changes in sample. Statistics derived from small sample sizes are particularly vulnerable to variations.

The table below shows the median values from the "All" data cut. The other percentiles and data cuts are available in the Excel file, where there is sufficient data to report.

			Base Salary	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Incentive %	Actual Total Cash	Total Cash Design
Job Code	Job Title	Nb. of Incumbents	P50	P50	P50	P50	P50	P50	P50
0000	President & Chief Executive Officer	31	$265,000	$207,500	$251,000	$267,800	26.25%	$314,000	$311,500
0001	Chief Operating Officer	8	$184,700	$158,200	$192,500	$205,400	12.43%	$206,000	$204,600
0002	Head of Operations and/or Engineering	22	$191,000	$151,700	$179,900	$200,100	15.44%	$207,500	$207,000
0003	Chief Financial Officer / Head of Finance	32	$182,300	$144,300	$176,400	$186,200	15.47%	$207,500	$202,700
0004	Head of Customer Service	7	$164,000	$127,100	$171,100	$182,000	14.56%	$183,700	$198,400
0005	Head of Regulatory Affairs	8	$184,200	$149,900	$176,500	$202,200	21.10%	$232,100	$208,100
0006	Head of Human Resources	17	$160,100	$135,600	$157,200	$173,400	14.95%	$177,000	$180,500
0007	Head of Information Technology / Information Services	13	$165,600	$140,100	$164,800	$179,300	17.83%	$203,500	$188,000
1000	Executive Assistant	25	$85,000	$71,500	$84,700	$97,100	5.45%	$89,800	$89,300
1001	Administrative Assistant	15	$73,300	$61,200	$70,400	$75,300	4.54%	$75,300	$73,800
2000	Director, Engineering	10	$152,300	$124,700	$156,600	$172,800	14.18%	$165,400	$174,000
2001	Engineering Manager / Distribution Engineer	28	$133,500	$112,400	$132,400	$144,900	6.75%	$139,400	$140,600
2002	Project Engineer	14	$105,500	$89,200	$109,700	$118,800	5.18%	$111,800	$112,700
2003	Supervisor, Engineering	14	$118,800	$95,600	$116,600	$134,800	5.00%	$124,900	$124,900
2500	Director, Operations	12	$149,300	$118,400	$143,200	$158,100	13.43%	$162,700	$157,500
2501	Manager, Operations	25	$135,000	$110,600	$130,300	$138,600	7.28%	$142,100	$137,600
2502	Manager, Control Centre	5	$150,000	$117,000	$130,800	$150,200	9.69%	$158,200	$150,200
2503	Supervisor, Control Centre	8	$118,700	$97,500	$112,100	$121,900	5.00%	$118,700	$118,400
2504	Supervisor, Protection and Control	6	$121,000	$96,100	$116,100	$124,900	4.67%	$126,300	$125,100
2505	Supervisor, Station Maintenance	7	$119,300	$96,000	$112,500	$120,000	-	$120,000	$118,900
2506	Line Supervisor	26	$117,100	$96,100	$113,400	$122,400	5.39%	$122,000	$118,800
2507	Manager, Meter Department	8	$126,300	$99,600	$120,300	$133,300	8.24%	$135,100	$129,200
2508	Supervisor, Meter Department	10	$111,200	$94,200	$110,700	$119,500	6.09%	$117,900	$119,000

Job Code	Job Title	Nb. of Incumbents	Base Salary P50	Salary Range Minimum P50	Job Rate P50	Salary Range Maximum P50	Target Incentive % P50	Actual Total Cash P50	Total Cash Design P50
2509	Manager, Continuous Improvement	5	$129,600	$111,800	$134,000	$154,100	9.17%	$140,600	$147,000
3000	Director, Supply Chain Management	5	$147,400	$108,400	$130,800	$156,500	10.79%	$167,600	$152,900
3001	Manager, Procurement and/or Inventory and/or Facilities and/or Fleet	15	$120,300	$98,300	$118,200	$131,100	7.00%	$123,700	$122,800
3002	Supervisor, Stores/Inventory/Warehouse	10	$105,100	$88,900	$108,100	$114,300	4.56%	$114,400	$111,700
4000	Controller / Director, Finance	13	$144,200	$115,000	$142,800	$164,300	10.19%	$160,600	$162,600
4001	Manager, Accounting	13	$130,300	$98,400	$121,400	$133,600	8.60%	$132,100	$131,200
4002	Manager, Risk Management	4	$130,000	$99,100	$128,200	$143,100	-	$145,400	$137,900
4003	Supervisor Accounting	13	$108,500	$91,500	$107,700	$118,900	5.47%	$114,600	$111,300
4004	Financial or Business Analyst	21	$95,600	$80,300	$96,800	$106,900	4.27%	$97,600	$102,500
4005	Accountant	8	$94,100	$77,200	$90,600	$102,100	7.00%	$95,400	$90,600
5000	Director, Customer Service	10	$146,300	$125,400	$145,200	$169,700	12.38%	$163,700	$164,100
5001	Manager, Customer Service and/or Billing	23	$113,400	$96,200	$117,400	$125,400	7.78%	$118,400	$119,100
5002	Supervisor, Customer Service and/or Billing and/or Collections	22	$98,800	$88,900	$103,500	$112,500	5.36%	$105,200	$106,100
5003	Key Account Specialist	4	$110,400	$88,000	$110,000	$123,900	-	$110,900	$120,800
5500	Director, Communications	5	$147,000	$114,100	$142,700	$150,500	11.06%	$155,000	$145,700
5501	Manager, Communications	9	$118,200	$100,900	$119,600	$128,500	6.18%	$119,100	$127,100
5502	Communications Specialist	18	$82,100	$71,600	$84,800	$94,000	4.80%	$84,900	$88,600
6000	Director, Regulatory Affairs	8	$144,300	$119,000	$142,700	$162,800	12.99%	$161,300	$161,100
6001	Manager, Regulatory Affairs	12	$126,700	$105,700	$119,600	$131,700	5.13%	$130,600	$124,900
6002	Regulatory Accountant	11	$97,300	$80,800	$97,000	$111,500	6.36%	$100,000	$103,600
7000	Settlement or Rate Analyst	5	$97,300	$84,200	$100,000	$114,900	4.05%	$108,100	$105,200
8000	Director, Information Systems	9	$150,200	$120,200	$150,200	$173,400	10.57%	$162,200	$173,900
8001	Manager, Information Systems	18	$132,600	$107,200	$127,300	$135,300	6.81%	$137,600	$130,700
8002	Systems and/or Program Administrator / Applications and/or Systems Support Professional	19	$104,900	$79,400	$101,400	$108,100	6.59%	$104,900	$103,200
8003	Manager Information Security	10	$129,400	$104,400	$129,600	$133,000	8.00%	$134,100	$137,100
8004	Network Specialist/Manager/Engineer	10	$108,000	$81,000	$99,800	$112,800	5.51%	$113,500	$106,900
9000	Human Resources Manager	13	$126,200	$108,400	$121,900	$135,500	7.61%	$126,200	$127,400
9001	Human Resources Generalist	14	$93,500	$82,300	$98,200	$105,100	3.32%	$96,700	$104,000
9002	Human Resources Coordinator	10	$76,500	$67,000	$80,800	$89,600	4.02%	$78,900	$85,200
9003	Payroll	14	$88,600	$72,200	$89,800	$98,500	5.00%	$92,100	$93,200

			Base Salary	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Incentive %	Actual Total Cash	Total Cash Design
Job Code	Job Title	Nb. of Incumbents	P50	P50	P50	P50	P50	P50	P50
9004	Manager, Health & Safety	19	$128,500	$100,900	$121,900	$133,600	8.20%	$134,500	$128,500
N001	Executive Role - Non Regulated Business	5	$198,000	$158,400	$200,500	$211,100	14.42%	$208,500	$236,600
N002	Non-Executive Role - Non Regulated Business	4	$110,400	$97,500	$112,200	$126,900	-	$112,200	$117,200

Appendix A: Survey Methodology

To formulate the information in this report, Eckler collected data, conducted quality assurance, and aggregated information to publish statistics.

A survey package was distributed to each participant that collected jobs data for the survey benchmark roles, as well as information on the organization's profile, salary administration policies, and benefits policies. Participants matched their jobs to the benchmark job profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, each unique data point was reviewed to ensure that all matches were accurate and should all be included. If all are valid, then each unique data point was used for that organization.

Eckler reviewed all submitted survey packages and contacted participants to verify the data provided, as necessary. Space was provided for additional comments with respect to the reported data for the role as well to ensure participants were able to provide any important context to the data of special circumstances that would influence the pay for an incumbent or position. If any of the submitted matches to the benchmark roles were deemed incorrect or not representative of the market, those outlier data points were removed from the aggregated survey results.

Appendix B: Terms and Definitions

For collecting compensation data, Eckler provided definitions for various compensation elements which form both compensation design – the intended range of pay for a position, as well as actual compensation – what an incumbent is currently being paid in the role.

Job Match Information

Data Collection Field	Description
Job Title within your Organization	The title used in your organization for the position you have matched to the benchmark.
Quality of Match	Your assessment of the "size" (scope/complexity) of the job in your organization compared the benchmark job description provided. For some positions, indicators of scope are discussed in the description; for others it will be a matter of subjective assessment. + The position in your organization has greater scope and/or complexity than the benchmark. Typically, the job would be perceived as at least 15% larger. For people managers, greater scope may include a larger than "typical" number of staff and/or wider range of activities/functions being managed or supervised. At senior management & executive levels, greater scope may also include additional functions reporting into this position (e.g., IT and Customer Service reporting to the CFO would make the job "wider" than the CFO in the benchmark description). = The position in your organization is of similar scope and/or complexity as the benchmark. Typically, the job would be perceived as within +/- 15% of the benchmark. - The position in your organization has smaller scope and/or complexity than the benchmark. Typically, the job would be perceived as at least 15% smaller (i.e., less than 85% of the scope/complexity of the benchmark). For people managers, scope may include a smaller than "typical" number of staff and/or narrower range of activities/functions being managed or supervised. At senior management & executive levels, smaller scope may include functions that would normally be expected to report into this position reporting elsewhere.
Work Location	The postal code of the work location for this position.
Standard Hours of Work	The standard hours of work per week.

Number of Incumbents	The number of incumbents in the position you have matched.
Pay Grade	The pay grade / job grade / grade level used within your organization to designate the level of the job.

Design Compensation: Salary Range

Data Collection Field	Description
Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	The salary your organization is prepared to pay for competent performance by a fully trained incumbent. This is typically the midpoint of a salary range or the highest step of a step structure.
Maximum	The highest point in the salary range or the highest step of a step structure.

Design Compensation: Short Term (Annual Incentive)

Data Collection Field	Description
Eligible? (Y/N)	Is the position typically eligible to participate in a defined incentive plan designed to reward the individual for performance/results achieved during a period of one year or less?
Target (%)	If the position is eligible, record the target bonus rate for the position if the target bonus is communicated as a percentage of base salary. Target bonus is the level of award that an employee in this position would expect to receive if all corporate, team and individual performance goals are met.
Target ($)	If the position is eligible, record the target bonus rate for the position if the target bonus is communicated as a dollar amount. Target bonus is the level of award that an employee in this position would expect to receive if all corporate, team and individual performance goals are met.

Discretionary	If the position is eligible and the bonus plan is "discretionary". Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executives / the board.

Actual Compensation

Data Collection Field	Description
Base Salary ($)	This is the annualized amount paid for work performed on a regular, ongoing basis. It does NOT include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments. Record on an annual, full time equivalent basis, as of April 1, 2023.
Bonus Paid ($)	Total of all short-term incentive awards paid to the incumbent(s) for performance/results over the previous year. If the incumbent joined the organization and/or became eligible for incentive pay during the year, and the actual bonus paid was on a pro-rated basis, please advise the annualized amount (before pro-rating).

Additional Information

Data Collection Field	Description
Comments / Additional Information	Record any information which you feel may assist in validating position matching or explaining special circumstances that influence pay.

Aggregated Statistics

Aggregated statistics are compiled by summing compensation elements; specifically, Eckler has prepared two aggregated statistics which provide a more holistic view of an incumbent's annual compensation.

- Total Cash Design: Salary Control Point or Job Rate + Incentive Target
- Actual Total Cash: Base Salary + Bonus Paid

Where a role is not provided with an incentive, Total Cash Design is equal to the Salary Control Point or Job Rate, and Actual Total Cash is equal to Base Salary.

Information surveyed is provided in aggregated form only to ensure that (1) data for individual organizations or incumbents is not disclosed and (2) to ensure a statistically relevant sample. Eckler requires a minimum number of observations to publish compensation statistics as follows:

Statistic	Definition	Minimum Number of Data Observations
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90th percentile and 90% would fall below.	12
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below.	8
P50	50th percentile, also referred to as “median” If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below.	4
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below.	8
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below.	12
Average	Average The arithmetic mean of all values, calculated by adding up all the values and dividing by the number of observations.	3

Appendix C: Benchmark Job Models

Executives

Job Code	Job Title	Description
0000	President & Chief Executive Officer	Directs the development of short- and long-term strategic plans, operational objectives, policies, budgets, and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures, and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
0001	Chief Operating Officer	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering, and information technology. Develops the short- and long-term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
0002	Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short- and long-term strategic plans, formulates and implements plans, budgets, policies, and procedures to facilitate and improve processes. Establishes clear controls, objectives, and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
0003	Chief Financial Officer / Head of Finance	Highest ranking financially oriented position within the company. Reporting to the President & CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders, and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
0004	Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services, and practices, including customer care/call centre, billing, credit, and collections. Accountable for the development, implementation, and integration of all customer service-related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies, and procedures; manages and coordinates budgets.

0005	Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally, reports to President & CEO or a senior executive.
0006	Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision, and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.
0007	Head of Information Technology / Information Services	The top information technology related position in the organization. Provides direction, support and alignment of organization-wide information technology practices and systems with the business in terms of mission, vision, and the strategic imperatives. Ensures that existing needs and future demands of internal and external customers are met through operationally secure and well-designed technology solutions. Directs staff/vendors in the development and implementation of information technology strategy & policies. This role will oversee software development, infrastructure development, end users support, data management, cyber security, project management, IT processes and business applications.

Administration

Job Code	Job Title	Description
1000	Executive Assistant	Performs advanced, diversified, and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings, and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares, and distributes minutes of meetings, including Board of

		Director minutes. Reports to the President & CEO and may provide support to other executives.
1001	Administrative Assistant	Performs advanced, diversified, and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings, and travel itineraries. Reports to a senior executive or executive team.

Engineering

Job Code	Job Title	Description
2000	Director, Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies, and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
2001	Engineering Manager / Distribution Engineer	"Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications, and designs, including the supervision, planning, and scheduling of work within the division – Requires a P. Eng. OR Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction, and maintenance of distribution systems. Consults with other department management on plant design, construction, and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.

2002	Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
2003	Supervisor, Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores, and maintains the integrity of hard copy file records, digital formats, and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Job Code	Job Title	Description
2500	Director, Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies, and procedures to facilitate and improve processes and establishes clear controls, objectives, and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
2501	Manager, Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules, and controls the construction, maintenance, and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance, and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
2502	Manager, Control Centre	Supervises, co-ordinates, directs, schedules, and controls the control centre and technical staff. Provide leadership in the planning and coordination of the control centre relative to safety, reliability, and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.

2503	Supervisor, Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
2504	Supervisor, Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance, and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
2505	Supervisor, Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinate and schedule the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports, and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work, and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
2506	Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications, and managing construction.
2507	Manager, Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions

		with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.
2508	Supervisor, Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors, and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.
2509	Manager, Continuous Improvement	Responsible for defining, measuring, and testing procedures in a company with an eye to improving operations/production/products/services efficiency. Analyzes maintains and/or improves organizational performance, using a variety of skills, such as project design, leadership, and management to ensure performance and process development and ultimately optimization. Qualifications: Engineering background.

Supply Chain / Procurement

Job Code	Job Title	Description
3000	Director, Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies, and procedures to facilitate and improve processes and establishes clear controls, objectives, and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements and provides contract management expertise and acts as a resource for contract negotiation, review, and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organization’s facilities and assets.

3001	Manager, Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
3002	Supervisor, Stores/Inventory/ Warehouse	Supervises inventory control, records, and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting/Finance

Job Code	Job Title	Description
4000	Controller / Director, Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices, and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends, and increased profit opportunities. Reports to a CFO/VP Finance.
4001	Manager, Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.

4002	Manager, Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for Ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.
4003	Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries, and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
4004	Financial or Business Analyst	Conducts analysis of information for budgeting, investment, and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; Process and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
4005	Accountant	Supports the organization decisions through financial information and relevant analysis. Ensure the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collect and combine information for the decision-making process by management, including financial statements and special projects as assigned (e.g., preparation of rate submission supplemental information).

Customer Service

Job Code	Job Title	Description
5000	Director, Customer Service	NOT the head of function. Provides direction for all departmental activities, services, and practices, including customer care/call centre, billing, credit, and collections. Accountable for the implementation and integration of all customer service-related activities. Oversees the implementation of customer service standards, policies, and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
5001	Manager, Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving, and responding to customer inquiries, complaint, or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits, and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational, and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
5002	Supervisor, Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.
5003	Key Account Specialist	Works the organizations' largest customers to ensure customer satisfaction as well as retain top customers and nurture those key relationships over time. Acts as a strategic partner and advisor to the client, providing services, resolving complaints and where appropriate discovering new opportunities, growing the business, and meeting customer needs.

Communications

Job Code	Job Title	Description
5500	Director, Communications	Directs the development, management, and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
5501	Manager, Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the customer communications. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.
5502	Communications Specialist	Responsible for providing communications support for internal and external communications. Evaluates and utilizes best platform for communication, including social media. Keeps current of industry and communication trends, monitoring communication efficacy and data as available to support the communications team by providing input to the overall communications plan. Assists in the development of key messages, composing press releases and preparing other communications materials (including website).

Regulatory Affairs

Job Code	Job Title	Description
6000	Director, Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
6001	Manager, Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs, and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
6002	Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudency review (i.e., conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation/Demand

Job Code	Job Title	Description
7000	Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating, and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.

Information Systems/Technology

Job Code	Job Title	Description
8000	Director, Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming, and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets, and resource requirements. Typically reports to the Chief IT role or may report directly to the CEO and/or CFO.
8001	Manager, Information Systems	Manages and directs staff in areas of computer operations, systems planning, design, programming, and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets, and resource requirements.

8002	Systems and/or Program Administrator / Applications and/or Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates, and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.
8003	Manager Information Security	Oversees all initiatives that concern the overall security of an organization’s technology assets and information. Defines strategies, policies, and procedures to ensure the integrity, confidentiality, and availability of the organization’s information. Manages and maintains the organization’s cyber security systems and infrastructure as well as the organization’s IT systems and computer networks against cyber-attacks, intrusions, malware, and various types of data breaches. Oversees the implementation of continued security improvements. Initiates auditing of current systems and risk assessments.
8004	Network Specialist/Manager/Engineer	Designs integrated IT infrastructure systems to support the organization's business needs. Analyzes and interprets business needs and delivers network solutions. Designs, installs, configures, and supports IT networks, including maintenance and troubleshooting. Develops and maintains documentation/policy relating to procedures, processes, and standards. Plans, tests, and implements upgrades and patches for networking equipment. Tunes network hardware and software to ensure optimum performance, resource utilization, and capabilities enhancement (technology strategy and road maps).

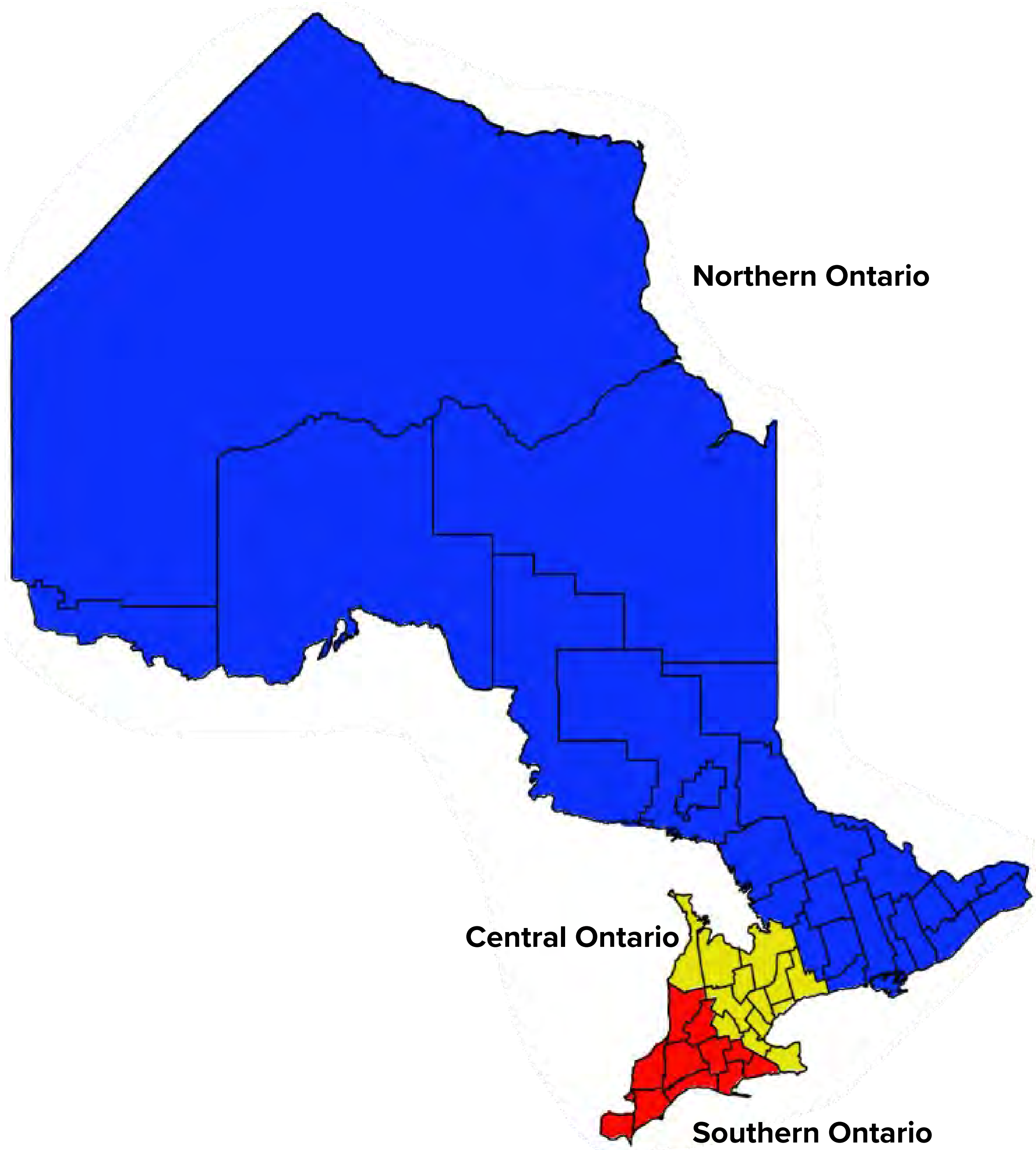
Human Resources

Job Code	Job Title	Description
9000	Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training, and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
9001	Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
9002	Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates, and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
9003	Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and respond to inquiries from employees and pensioners regarding the pension plan.
9004	Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety, and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Non-Regulated Business – Business Development Roles

Job Code	Job Title	Description
N001	Executive Role - Non-Regulated Business	Reporting to either/or the CEO or the Board, this role is responsible for non-regulated revenue streams, and achieving growth/revenue targets for the organization. This includes the development of new offerings, enhancing existing offerings or creating value for clients by diversifying the organization's services. They are responsible for maintaining and growing client relationships as well as building relationships with additional clients in the market. May be supported by analytical staff or more junior business development roles.
N002	Non-Executive Role - Non-Regulated Business	Reporting to an executive within an LDC or an executive in a sister/nonregulated company, this role is responsible for non-regulated revenue generation. They will have growth/revenue targets for the organization and are focused on maintaining/growing relationships with clients by enhancing existing offerings or creating value by diversifying the organization's services. They may also support the development of additional market offerings.

Appendix D: Region Map



Appendix E: About Eckler

Established in 1927, Eckler Ltd. is one of the longest-established and most respected consulting and actuarial practices in Canada. With over 300 employees, we are the largest independent benefits and pensions consulting firm in the country. Our head office is located in Toronto, with additional offices in Winnipeg, Vancouver, Montreal, Quebec City, and Halifax; and two offices in the Caribbean (Jamaica and Barbados). In November 2021, Eckler was recognized by Waterstone Human Capital as one of Canada's Most Admired Corporate Cultures for 2021. We have once again been awarded this honour in 2022. Eckler have always been guided by our democratic culture of trust and commitment to purpose.

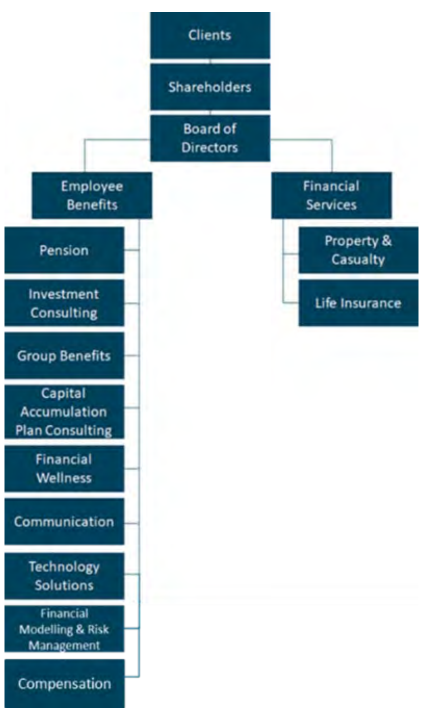
We have evolved from a strictly actuarial firm to a fully integrated consulting practice, offering a complete range of employee benefit services including group benefits consulting, investment consulting, asset/liability modelling, technology solutions, communication and change management consulting, defined contribution plan consulting, compensation consulting, as well as financial wellbeing education.

We are a privately-owned company with Principal Shareholders who are actively involved in our consulting practice. Each Shareholder owns an equal number of shares in the firm, which ensures a highly democratic and equitable distribution of authority and responsibility. This operational structure helps us to maintain a strong entrepreneurial culture while ensuring stability.

Eckler has a unique organizational structure that consists of two distinct business units:

- Employee benefits which provides consulting services primarily to sponsors of pension and benefits plans; and

- Financial services, which consults primarily to insurance and other financial services companies.



Compensation Experience with Surveys

Understanding compensation, and specialized fields and industries can be very challenging. As a result, many sectors opt to conduct surveys that are specific to their own sector to obtain a clearer picture of the available talent in the market, and the cost of that talent. With high inflation, and a shrinking labour pool in Canada for many professions, and a growing trend of needing to compete on a regional or even national level when work is remote/hybrid enabled, organizations are facing unprecedented challenges to attract, recruit, and retain talent.

We have supported many organizations in developing programs that recognize workforces being a significant asset, and designing total rewards programs and communications plans that better position their total rewards strategically. In all our projects, our insights and program development are based upon reliable industry data which is a core deliverable of this project.

Our compensation team is located in Toronto, Vancouver, and Montreal, with several of the staff members having experience in running large scale national surveys, as well as specific industry or profession surveys. In addition to our core consulting team, we also have communications and technology solutions that may be useful to leverage for communicating data insights, and assisting in how the data should be published.

Examples of surveys led by our consulting staff previously:

- National Compensation Database – over 700 organizations, including multinational corporations and 600,000+ incumbents
- Canadian post secondary institutions survey – over 50 participants focused on executive compensation data
- Wealth Management survey – approximately 30 participants annually with a focus on 40 jobs, specializing in mutual fund sales
- Credit Union Surveys
- Healthcare surveys – focusing on several benchmark roles specific to primary care delivery and organizations in Ontario but also some nationally

Need more information about Eckler or have a question about this report?

Contact compconsulting@eckler.ca and an Eckler colleague will respond to you.

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Attachment 4

6-Staff-33 a) – 2023 FHI PILs Return

Canada Revenue Agency | Agence du revenu du Canada

Scientific Research and Experimental Development (SR&ED) Expenditures Claim

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, Investment Tax Credit – Corporations; or
- Form T2038(IND), Investment Tax Credit (Individuals).

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information.

In Part 6, a new box is added: Box 758 that must be filled if traditional method is used. The information is required for tax year ends after 2020 and optional for tax year ends before 2021.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, Guide to Form T661, which is available on our website: **canada.ca/taxes-sred**.

Part 1 – General information

010 Name of claimant: Festival Hydro Inc.

Enter one of the following:

Business number (BN): 89957 1814 RC0002

Social insurance number (SIN):

Tax year From 2023-01-01 (Year Month Day) to 2023-12-31 (Year Month Day)

050 Total number of projects you are claiming this tax year: 1

100 Contact person for the financial information: Alyson Conrad	**105** Telephone number/extension: (519) 271-4700	**110** Fax number
115 Contact person for the technical information: [redacted]	**120** Telephone number/extension: [redacted]	**125** Fax number

151 If this claim is filed for a partnership, was Form T5013 Partnership Information Return filed? . . . . ☐ Yes ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method (Enter "0" on line 360 and complete Part 5.)

162 [ ] I choose to use the traditional method (Enter "0" on line 502. Complete line 360.)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	58,539
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	58,539
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	79,625
b) Non-arm's length contracts	345	+	
• Overhead and other expenditures (enter "0" if you elected to use the proxy method at line 160)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total allowable SR&ED expenditures (add lines 306 to 370; do not add line 315)	380	=	138,164

If the above expenditures have been included in your income statement, enter this amount on line 118 of Schedule T2SCH1 or, if you are an individual, include this amount in your self-employment income (lines 135 to 143) reported on your individual income tax and benefit return.

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 380	420		138,164
Deduct			
• provincial government assistance for expenditures included on line 380	429	–	4,278
• other government assistance for expenditures included on line 380	431	–	
• non-government assistance for expenditures included on line 380	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (do not include ITCs allocated from a partnership)	435	–	14,776
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	119,110
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	119,110
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	119,110
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, Third-Party Payments for Scientific Research and Experimental Development (SR&ED)

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes (to the nearest dollar)

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Total allowable SR&ED expenditures (from line 380)	492		138,164
Add			
• payment of prior years' unpaid amounts (other than salary or wages) (see note 1)	500	+	
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502	+	32,094
• qualified expenditures transferred to you (see note 3) (complete Form T1146**)	508	+	
Subtotal (add lines 492 to 508)	511	=	170,258
Deduct			
• provincial government assistance	513	–	5,402
• other government assistance	515	–	
• non-government assistance and contract payments	517	–	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end (see **note 1**)	520	–	
• 80% of the amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier	528	–	
• 20% of the amount on lines 340 and 370	529	–	15,925
• prescribed expenditures not allowed by regulations (see guide)	530	–	
• other deductions (see guide)	533	–	
• non-arm's length transactions			
– assistance allocated to you (complete Form T1145*)	538	–	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541	–	
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542	–	
– qualified expenditures you transferred (complete Form T1146**)	544	–	
Qualified SR&ED expenditures (line 511 minus lines 513 to 544)	559	=	148,931
Add			
• repayments of assistance and contract payments made in the year	560	+	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)	570	=	148,931

* Form T1145, Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length

** Form T1146, Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length

Note 1 – For arm's length contracts, only include 80% of the contract amount.

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162). You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from lines 300 and 307)	810	+	58,539
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	812	–	187
Subtotal (line 810 minus 812)	814	=	58,352

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816)	816	+	
Salary base (total of lines 814 and 816)	818	=	58,352

Section B – Prescribed proxy amount (PPA)

Enter 55 % of the salary base (line 818)	820	=	32,094

Enter the amount from line 820 on to line 502 in Part 4 unless the overall cap on PPA applies to you. (See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

* For Box 758, the information is required for tax year ends after 2020 and optional for tax year ends before 2021.

750	752	754	756	758
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)	Overhead and other expenditures in the tax year* (total of line 360, if applicable)
1 FH2023-01 Data Mapping Techniques for CIS Design	58,539		79,625	
Total	58,539		79,625	

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 380 minus lines 307, 309, 340, 345, and 370) 605 58,539

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

620 ☐ Basic or Applied research 622 ☒ Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	1
Technologists and technicians	634	
Managers and administrators	636	1
Other technical supporting staff	638	1

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form ☒
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 ☒
3. completed Part 2 for each project ☒
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures ☒
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable ☒

To expedite the processing of your claim, make sure you have:

1. completed Form T2, Corporation Income Tax Return or Form T1, Income Tax and Benefit Return ☒
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable ☒
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed ☒
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 ☒

* Form T1145, Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length

** Form T1146, Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length

*** Form T1174, Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)

**** Form T1263, Third-Party Payments for Scientific Research and Experimental Development (SR&ED)

Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

A $1,000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.

935 **Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?**

- [X] Yes (complete the claim preparer information table and lines 970 and 975 below)
- [ ] No (complete lines 970 and 975)

Claim preparer information table

940	945	950	955	960	965
Name of claim preparer (company or individual)	Business number	Billing arrangement code (see codes below*)	Billing rate (percentage, hourly/daily rate or flat fee)	Other billing arrangement(s) (Maximum 10 words)	Total fee paid, payable, or expected to pay
1. KPMG LLP	12236 3153 RC0001	1	25.00		6,935
				Total	6,935

*** Billing arrangement codes**

Code	Type of billing arrangement
1	Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned
2	Hourly rate
3	Daily rate
4	Flat fee arrangement (lump sum)
5	Other arrangements – describe the arrangement in box 960 in 10 words or less

970 I, Alyson Conrad, certify that the information provided in this part is complete and accurate.
Name of authorized signing officer of the corporation, or individual (print)

Signature

975 2024-06-03
Year Month Day

Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Alyson Conrad		**170**
Name of authorized signing officer of the corporation, or individual	Signature	Date
175 KPMG LLP		
Name of person/firm who completed this form		

Privacy Notice

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the Income Tax Act (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including assessment, audit, enforcement, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Refer to Personal Information Bank CRA PPU 441 in the Canada Revenue Agency (CRA) Information about Programs and Information Holdings – Personal Information Banks – Canada.ca. Under the Privacy Act, individuals have a right of access to, protection, and correction of their personal information and to file a complaint with the Privacy Commissioner of Canada regarding our handling of their personal information.

Part 2 – Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

FH2023-01 Data Mapping Techniques for CIS Design

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2023-04 (Year Month)	2024-07 (Year Month)	1.02.02 Information technology and bioinformatics (Software

Project claim history

208 ☐ Continuation of a previously claimed project   **210** ☒ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . ☒ Yes ☐ No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1	Festival Hydro Services Inc.	86295 3726 RC0001
2		
3		

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

Festival Hydro (FH) Inc. is a local distributor of electrical power to over 22000 customers in the community of Stratford and surrounding areas. The company provides both residential and commercial services through efficient operation and continual improvements in its electrical distribution system. In FY23, Festival Hydro sought to update its legacy and deprecated Customer Information System (CIS) solution with a new and upgraded CIS platform. This was because of the inability of the legacy CIS provider in performing frequent code-level customizations to accommodate new billing and meter data changes. With an objective of addressing this issue, Festival Hydro sought to implement a new CIS system that could provide flexible customer focused metering, billing, and service capabilities. Additionally, efforts were undertaken to prepare the service architecture to support improved decision making and also aid in real-time reporting and usage data analysis. This required a CIS that could directly interface with the various internal sub-systems in the electric grid, particularly the GIS (Geographical Information Systems) and MDM (Meter Data Management) modules, while eliminating any process silos. Investigations were carried out to evaluate and possibly integrate a third party (JOMAR) CIS solution with an adaptable design and high-volume data processing capacity. The underlying challenge was how to reliably integrate the data channels between the aforementioned sub-systems owing to the presence of interoperability challenges between them. Systematic investigations were therefore required to address these issues.

Note, this project was a shared initiative between Festival Hydro Inc. and Festival Hydro Services Inc. Only costs incurred by Festival Hydro Inc. are included in this submission.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

Festival Hydro sought to develop advanced data manipulation techniques to move the customer data into the new CIS platform. Additionally, efforts were undertaken to utilize the capabilities of the new CIS for delivering real-time usage data views, consolidated billing options and flexible notification services to the account users. This required analyzing and remodeling the existing data relationships between the CIS and other utility sub-systems

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

including OMS (Outage Management system), MDM (meter data management) and GIS modules. In the initial phase attempt was to split the existing system design and identify the customized data components that relayed the data for the various billing and customer level transactions. A subset of these modules included service location processor, load rate order unit, GA (Global Adjustment) rate, retail (EBT) transactions engine. Furthermore, tests were performed to review the connectivity to the MDM/R sub-system and ensure seamless transfer of the interval meter data. In the next phase, efforts were concentrated on transporting the historical data records linked to the aforementioned modules inside the new CIS database. Such recovery operations were necessary to maintain a reliable record of past transactions and also for FH to continue to support any future nodal data requests. To this end, data mapping procedures were developed to connect the source (old CIS) data tables to the destination (new CIS) data locations and establish a single source of truth. Another major challenge was to standardize the original data such that is could be readily ingested and processed by the new CIS engine. Disparate data structures were filtered for this purpose and the data formats were stored to limit the possibility of data errors or gaps in the final database and through this increase the ability to construct actionable data insights. In addition, conversion functions were developed to transform the incoming data batches into the desired schema structure and ensured delivery of quality data.

Another key development area was to retain the current interfaces from the CIS to other third-party applications including "SmartMAP" and Green Button platform. These interfaces facilitated the real-time transmission of meter data and account-specific information, which were essential for providing improved outage services and for satisfying regulatory data sharing standards. Programming scripts were developed to re-establish the interface channels and route the data between the two systems. Post these development activities, work was set to continue in this project in FY24. The objective was to incorporate additional third-party tools into the new CIS solution and also execute parallel testing to detect any data inconsistencies or integration failures.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

The work performed in FY2023 represents a technological advancement in the field of electrical and IT systems. The project contributed to following advancements:

The techniques as developed by Festival Hydro would allow it to successfully integrate the new CIS platform with the existing utility modules such as the GIS, MDM, and OMS Sub-systems. Moreover, by developing customized data mapping and conversion procedures, Festival Hydro harmonized the disparate data relationships between the new CIS database and the source data warehouse. This essentially presented an approach for consolidating multi-account billing structures in a single bill structure while also expanding the system capabilities in serving custom user requests in a flexible manner.

Section C – Additional project information

Who prepared the responses for Section B?

253 ☐ Employee directly involved in the project	254 Name		
255 ☐ Other employee of the company	256 Name		
257 ☒ External consultant	258 Name KPMG LLP	259 Firm KPMG LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	261 Qualifications/experience and position title
1 [redacted]	Director, Master of Engineering Science with over 28 years of experience in development and maintenance of utility systems
2 [redacted]	Manager IT with over 22 years of experience in design and development of grid related IT systems
3	

265	Are you claiming any salary or wages for SR&ED performed outside Canada?	☐ Yes	☒ No
266	Are you claiming expenditures for SR&ED carried out on behalf of another party?	☐ Yes	☒ No
267	Are you claiming expenditures for SR&ED performed by people other than your employees?	☒ Yes	☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	269 BN
1 JOMAR Softcorp Services Inc.	87641 2511 RT0001

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	☒ Project planning documents	276	☒ Progress reports, minutes of project meetings
271	☒ Records of resources allocated to the project, time sheets	277	☒ Test protocols, test data, analysis of test results, conclusions
272	☐ Design of experiments	278	☐ Photographs and videos
273	☐ Project records, laboratory notebooks	279	☐ Samples, prototypes, scrap or other artefacts
274	☒ Design, system architecture and source code	280	☒ Contracts
275	☒ Records of trial runs	281	☐ Others, specify 282

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2024-12-31

Business number 89957 1814 RC0002

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

You can pay using one of the methods listed at **canada.ca/payments**. However, when a remittance must mandatorily be made using electronic means, use one of the following electronic payment methods:

- a Canadian financial institution's services;
- the CRA's *My Payment* service, at **canada.ca/cra-my-payment**;
- a pre-authorized debit agreement set up in the CRA's *My Business Account* service, at **canada.ca/my-cra-business-account**;
- a wire transfer.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2024-01-31	18,531				18,531
2024-02-29	18,531				18,531
2024-03-31	18,531				18,531
2024-04-30	18,531				18,531
2024-05-31	18,531				18,531
2024-06-30	18,531				18,531
2024-07-31	18,531				18,531
2024-08-31	18,531				18,531
2024-09-30	18,531				18,531
2024-10-31	18,531				18,531
2024-11-30	18,531				18,531
2024-12-31	18,523				18,523
Totals	222,364				222,364

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) 001 89957 1814 RC0002

Corporation's name
002 Festival Hydro Inc.

Address of head office
Has this address changed since the last time the CRA was notified? .... 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 187 Erie Street
012
City: 015 Stratford — Province, territory, or state: 016 ON
Country (other than Canada): 017 — Postal or ZIP code: 018 N5A 2M6

Mailing address (if different from head office address)
Has this address changed since the last time the CRA was notified? .... 020 Yes [ ] No [X]
If **yes**, complete lines 021 to 028.
021 c/o
022
023
City: 025 — Province, territory, or state: 026
Country (other than Canada): 027 — Postal or ZIP code: 028

Location of books and records (if different from head office address)
Has this address changed since the last time the CRA was notified? .... 030 Yes [ ] No [X]
If **yes**, complete lines 031 to 038.
031
032
City: 035 — Province, territory, or state: 036
Country (other than Canada): 037 — Postal or ZIP code: 038

040 **Type of corporation at the end of the tax year** (tick one)
- [X] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change .... 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2023-01-01
Tax year-end: 061 Year Month Day 2023-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? .... 063 Yes [ ] No [X]
If **yes**, provide the date control was acquired .... 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? .... 066 Yes [ ] No [X]

Is the corporation a professional corporation that is a member of a partnership? .... 067 Yes [ ] No [X]

Is this the first year of filing after:
Incorporation? .... 070 Yes [ ] No [X]
Amalgamation? .... 071 Yes [ ] No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... 072 Yes [ ] No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... 076 Yes [ ] No [X]

Is this the final return up to dissolution? .... 078 Yes [ ] No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes [X] No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? .... 082 Yes [ ] No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits or zero-emission technology manufacturing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273		63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274		59
Is the corporation claiming an air quality improvement tax credit?	275		65
Is the corporation subject to the additional 1.5% tax on banks and life insurers?	276		68
Is the corporation a covered entity that redeemed, acquired or cancelled equity of the corporation in the tax year?	277		56

Additional information

		Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X	
Is the corporation inactive?	280		X
Did the corporation meet the definition of substantive CCPC under subsection 248(1) at any time during the tax year?	290		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Hydro Services	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

		Yes	No
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		969,418	A
Deduct:				
Charitable donations from Schedule 2	311	6,751		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities	352			
Subtotal		6,751	▶ 6,751	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			962,667	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		962,667	
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7	400	969,418	A
Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	962,667	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction for tax years starting before April 7, 2022

Amount C 500,000 x 415 *** 139,314 D / 11,250 = ... ______ E1

Taxable capital business limit reduction for tax years starting after April 6, 2022

Amount C 500,000 x 415 *** 139,314 D / 90,000 = ... 773,967 E2

Amount E1 or amount E2, whichever applies 773,967 ▶ 773,967 E3

Passive income business limit reduction

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

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

The greater of amount E3 and amount G	422	773,967	H
Reduced business limit (amount C **minus** amount H) (if negative, enter "0")	426		I
Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below)			J
Reduced business limit after assignment (amount I **minus** amount J)	428		K
Small business deduction – Amount A, B, C, or K, whichever is the least .... ______ x 19 % =	430		

Enter amount from line 430 at amount K on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Small business deduction (continued)

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount 490	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] 500	N Business limit assigned to corporation identified in column L [4] 505
1.				
			Total 510	Total 515

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Taxable income from line 360 on page 3			962,667	A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B		
Amount 13K from Part 13 of Schedule 27		C		
Personal services business income 432		D		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*		E		
Aggregate investment income from line 440 on page 6**		F		
Subtotal (**add** amounts B to F)		▶		G
Amount A **minus** amount G (if negative, enter "0")			962,667	H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %			125,147	I

Enter amount I on line 638 on page 8.

* This is not applicable to substantive CCPCs.

** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, a substantive CCPC, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3				J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		K		
Amount 13K from Part 13 of Schedule 27		L		
Personal services business income 434		M		
Subtotal (**add** amounts K to M)		▶		N
Amount J **minus** amount N (if negative, enter "0")				O
General tax reduction – Amount O **multiplied** by 13 %				P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x 30 2 / 3 % =			A
Foreign non-business income tax credit from line 632 on page 8		B	
Foreign investment income from Schedule 7 . . . . **445** ______ x 8 % =		C	
Subtotal (amount B **minus** amount C) (if negative, enter "0")		▶	D
Amount A **minus** amount D (if negative, enter "0")			E
Taxable income from line 360 on page 3	962,667	F	
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least* . . . . ______ G			
Foreign non-business income tax credit from line 632 on page 8 . . . . ______ x 75 / 29 = ______ H			
Foreign business income tax credit from line 636 on page 8 . . ______ x 4 = ______ I			
Subtotal (**add** amounts G to I) ______ ▶		J	
Subtotal (amount F **minus** amount J)	962,667	K x 30 2 / 3 % =	295,218 L
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9)			120,059 M
Refundable portion of Part I tax – Amount E, L, or M, whichever is the least **450**			N

* This is not applicable to substantive CCPCs.

Refundable dividend tax on hand

Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (line 530 of the preceding tax year)	520	A
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (line 545 of the preceding tax year) (if negative, enter "0")	535	B
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)		C
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)		D
Subtotal (amount C **plus** amount D)	►	E
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525	F
ERDTOH dividend refund for the previous tax year	570	G
Refundable portion of Part I tax (from line 450 on page 6)		H
Part IV tax before deductions (amount 2A from Schedule 3)		I
Part IV tax allocated to ERDTOH (amount E)		J
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)		K
Subtotal (amount I **minus** total of amounts J and K)	►	L
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540	M
NERDTOH dividend refund for the previous tax year	575	N
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)		O
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount L **minus** amount O) (if negative enter "0")		P
NERDTOH at the end of the tax year (total of amounts B, H, M, and P **minus** amount N) (if negative, enter "0")	545	
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount E **minus** the amount, if any, by which amount O exceeds amount L) (if negative, enter "0")		Q
ERDTOH at the end of the tax year (total of amounts A, F, and Q **minus** amount G) (if negative, enter "0")	530	

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	239,231	DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")	239,231	GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 %			550	365,813 A
Additional tax on personal services business income (section 123.5)				
Taxable income from a personal services business	555	x 5 % =	560	B
Additional tax on banks and life insurers from Schedule 68			565	C
Recapture of investment tax credit from Schedule 31			602	D

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) or substantive CCPC's investment income (if it was a CCPC throughout the tax year or a substantive CCPC at any time in the tax year)

Aggregate investment income from line 440 on page 6		E
Taxable income from line 360 on page 3	962,667 F	
Deduct:		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*	G	
Net amount (amount F **minus** amount G)	962,667 ▶	962,667 H

Refundable tax on CCPC's or substantive CCPC's investment income – 10 2 / 3 % of whichever is less: amount E or amount H	604	I
Subtotal (**add** amounts A, B, C, D, and I)		365,813 J

Deduct:

Small business deduction from line 430 on page 4		K	
Federal tax abatement	608	96,267	
Manufacturing and processing profits deduction and zero-emission technology manufacturing deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount I on page 5	638	125,147	
General tax reduction from amount P on page 5	639		
Federal logging tax credit from Schedule 21	640		
Eligible Canadian bank deduction under section 125.21	641		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	24,340	
Subtotal		245,754 ▶	245,754 L

Part I tax payable – Amount J **minus** amount L	120,059 M

Enter amount M on line 700 on page 9.

* This is not applicable to substantive CCPCs.

Privacy notice

Personal information (including the SIN) is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

Summary of tax and credits

Federal tax

Part I tax payable from amount M on page 8	700	120,059
Part II.2 tax payable from Schedule 56	705	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part VI.2 tax payable from Schedule 67	725	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		120,059

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	102,305
Total tax payable	770	222,364 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount JJ on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795	
Canadian film or video production tax credit (Form T1131)	796	
Film or video production services tax credit (Form T1177)	797	
Canadian journalism labour tax credit from Schedule 58	798	
Air quality improvement tax credit from Schedule 65	799	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	246,000
Total credits	890	246,000 ▶ 246,000 B

Balance (amount A **minus** amount B) -23,636

If the result is negative, you have **a refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, the CRA does not charge or refund a difference of $2 or less.

Refund code 894 1 Refund 23,636 Balance owing

For information on how to enrol for direct deposit, go to **canada.ca/cra-direct-deposit**.

For information on how to make your payment, go to **canada.ca/payments**.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their: EFILE number 920 A4970

RepID 925

Certification

I, 950 Conrad (Last name) 951 Alyson (First name) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 271-4700 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☒ No ☐

958 ______ Name of other authorized person 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Financial Statements of

Festival Hydro Inc.

Year ended December 31, 2023

KPMG LLP
140 Fullarton Street, Suite 1400
London, ON N6A 5P2
Canada
Telephone 519 672 4880
Fax 519 672 5684

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.

Schedule of Instalment Remittances

Name of corporation contact: Erin Smith

Telephone number:

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Payments for 2023	246,000

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	246,000	**A**
Total instalments credited to the taxation year per T9	246,000	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Festival Hydro Inc.

89957 1814 RC0001

December 31, 2023

<u>Letter to Minister for elections made by the corporation for which there is no prescribed form</u>

Election under Subsection 1101(5b.1) of the Income Tax Regulations

The above taxpayer elects under subsection 1101(5b.1) to include in a separate class the cost of building additions in the amount of $1,060,506 in accordance with Regulation 1100(1)(a.2) for a property of the taxpayer that is a building, at least 90 per cent of the floor space of which is used at the end of the taxation year for a non-residential use in Canada.

Election under Subsection 13(7.4) to reduce the capital cost of depreciable property where inducement received.

The above taxpayer hereby elects to have subsection 13(7.4) apply to reduce the capital cost of the depreciable property listed below with respect of assistance received in the 2023 taxation year.

Capital Property: Distribution Assets, Class 47 Acquired during 2023. Cost $466,382

Assistance: Capital contributions $466,382, Received during 2023.

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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Notes to the financial statements

Election under Subsection 1101(5b.1) of the Income Tax Regulations
The above taxpayer elects under subsection 1101(5b.1) to include in a separate class the cost of building additions in the amount of $1,060,506 in accordance with Regulation 1100(1)(a.2) for a property of the taxpayer that is a building, at least 90 per cent of the floor space of which is used at the end of the taxation year for a non-residential use in Canada.
Election under Subsection 13(7.4) to reduce the capital cost of depreciable property where inducement received.
The above taxpayer hereby elects to have subsection 13(7.4) apply to reduce the capital cost of the depreciable property listed below with respect of assistance received in the 2023 taxation year.
Capital Property: Distribution Assets, Class 47 Acquired during 2023. Cost $466,382
Assistance: Capital contributions $466,382, Received during 2023.
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 April25, 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 amortizationperiod
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 ofproperty, plant and equipment.
Note 9 Intangible assets: useful lives and goodwill impairment testing.
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Note 23 Recognition and measurement of commitments and contingencies.
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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 processrequirements 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 thatreview.

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.Festival Hydro Inc.

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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 andvariance 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 andvariance 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 financialstatements 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 orOCI.
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.Festival Hydro Inc.

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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 thestatement 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 theshort 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

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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.Festival Hydro Inc.
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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 theStatement 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 infrastructureto property, plant and equipment.
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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 selfconstructed
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 yearsare 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.
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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 recoveryagreements ("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 andaccumulated 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 usefullives 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 andadjusted if appropriate.
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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 creditlosses 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 creditlosses 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,

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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.
Festival Hydro Inc.
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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 bythe 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

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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.
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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 monthsafter 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 electricityrevenue on a gross basis.
Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as anagent 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.Festival Hydro Inc.
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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 usefullife 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 thecorresponding 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 rightof-use asset has been reduced to zero.

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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 creditfacility 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 orcapital 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.Festival Hydro Inc.
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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 thestatements 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 AccountingEstimates 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 12Income 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 financialstatements.
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4. Future accounting pronouncements:

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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 financialstatements 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 amendmentsare 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.

Festival Hydro Inc.

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

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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

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(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.
Festival Hydro Inc.
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22
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
$70,489,438Additions 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
$73,772,693Additions 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
$77,961,747b) 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
$13,375,529Depreciation 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
$14,918,660Depreciation 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 $
16,808,891c) Carrying amounts
Land and
buildings
Distribution &

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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.Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
23
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

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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'svalue in use.
Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
24
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 atDecember 31, 2023 or December 31, 2022.
10. Income taxes:
2023 2022
Income tax expense
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
Increase (decrease) in income tax resulting from:
Permanent differences
Recognized deductible temporary difference due from customers
Other
605,255
2,060

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(115,983)
2,490
1,189,011
2,212
(1,072,384)
(14,439)
Income tax expense $ 493,822 $ 104,400
Festival Hydro Inc.
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Year ended December 31, 2023, with comparative information for 2022
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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 primebusiness 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.
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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 beenallocated 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

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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 regulatorybalances.
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 relatedto 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
Festival Hydro Inc.
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13. Regulatory assets and liabilities (continued):
January 1, 2023 Transactions Recovery/

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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)
(
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 becollected 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 wascleared 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

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recovery of variance accounts is limited to
the incremental value of non-settlement variances arising since 2021.
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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.Festival Hydro Inc.
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14. Long-term debt continued:
Reconciliation of movements of liabilities to cash flows arising from financing activities:Current
and longterm
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) $ 1,132,937Dividend 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).Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
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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

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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 andservice 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
Festival Hydro Inc.
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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).
Festival Hydro Inc.

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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Year ended December 31, 2023, with comparative information for 2022
33
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 payableand accrued charges is $611,591 (2022 - $630,031).
Dividends paid or payable $ 624,080 $ 638,599
Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
34
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

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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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).Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
35
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 nomore 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 associatedwith its long-term debt.
22. Financial instruments and risk management:
Fair value disclosure
The carrying values of accounts receivable, unbilled revenue, due to

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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Notes to the financial statements

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:
Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
36
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 andliquidity risk.

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Notes to the financial statements

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.
Festival Hydro Inc.
Notes to the Financial Statements
Year ended December 31, 2023, with comparative information for 2022
37
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 theamount 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 itsservice 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 thecredit 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 forimpairment 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).
Festival Hydro Inc.
Notes to the Financial Statements

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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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 shortterm
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 anappropriate 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 whileminimizing 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:

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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Notes to the financial statements

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
Festival Hydro Inc.
Notes to the Financial Statements

Corporation's name	Business number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

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Year ended December 31, 2023, with comparative information for 2022
40
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 thetransformer 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,

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results of operations or its ability to carry onany 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.Festival Hydro Inc.
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Year ended December 31, 2023, with comparative information for 2022
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24. Comparative figures:
Certain comparative figures have been restated to conform to the current year
presentation.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,790,160	A
Add:				
Provision for income taxes – current	101	493,822		
Amortization of tangible assets	104	2,619,161		
Charitable donations and gifts from Schedule 2	112	6,751		
Scientific research expenditures deducted per financial statements	118	138,164		
Non-deductible meals and entertainment expenses	121	7,773		
Reserves from financial statements – balance at the end of the year	126	1,211,945		
Subtotal of additions		4,477,616 ▶	4,477,616	

Add:

Other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	3,752
2	Contributed capital	466,382
3	Unrealized loss on SWAP	330,131
	Total of column 2	800,265

Total of column 2 ▶	296	800,265		
Subtotal of other additions	199	800,265 ▶	800,265	D
Total additions	500	5,277,881 ▶	5,277,881	
Amount A **plus** line 500			7,068,041	B
Deduct:				
Capital cost allowance from Schedule 8	403	4,092,875		
SR&ED expenditures claimed in the year on line 460 from Form T661	411	119,110		
Reserves from financial statements – balance at the beginning of the year	414	1,181,874		
Subtotal of deductions		5,393,859 ▶	5,393,859	

Deduct:

Other deductions:

	1 Description 705	2 Amount 395
1	Amortization of deferred revenue	76,869
2	Coop and ATTC and SRED	23,349
3	Election under subsection 13(7.4)	466,382
4	Unrealized gain re Mark to Market	0
5	Capitalized SR&ED Cost	138,164
	Total of column 2	704,764

Total of column 2 ▶ 396 704,764

Subtotal of other deductions	499	704,764 ▶	704,764 E
Total deductions	510	6,098,623 ▶	6,098,623
Net income (loss) for income tax purposes (amount B **minus** line 510)			969,418 C

Enter amount C on line 300 of the T2 return.

Canada

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Ontario

A		
X	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	752
X	Ontario co-operative education tax credit	3,000
	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario book publishing tax credit	
X	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
	Ontario business-research institute tax credit	
	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  - the eligible amount of gifts of certified cultural property
  - the eligible amount of gifts of certified ecologically sensitive land or
  - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Various	6,751
Subtotal	6,751
Add: Total donations of less than $100 each	
Total donations in current tax year	6,751

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			1A		
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1, Net Income (Loss) for Income Tax Purposes)	210	6,751		6,751	6,751
Subtotal (line 250 **plus** line 210)		6,751	1B	6,751	6,751
Subtotal (line 240 **plus** amount 1B)		6,751	1C	6,751	6,751
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		6,751	1D	6,751	6,751
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2) (enter this amount on line 311 of the T2 return)	260	6,751		6,751	6,751
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . . **262** ______

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . . ______ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . . **263** ______

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . . ______ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016, and before January 1, 2027) . . . . . . **265** ______

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . . ______ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2022-12-31			
2nd prior year	2021-12-31			
3rd prior year	2020-12-31			
4th prior year	2019-12-31			
5th prior year	2018-12-31			
6th prior year*	2017-12-31			
7th prior year	2016-12-31			
8th prior year	2015-12-31			
9th prior year	2014-12-31			
10th prior year	2013-12-31			
11th prior year	2012-12-31			
12th prior year	2011-12-31			
13th prior year	2010-12-31			
14th prior year	2009-12-31			
15th prior year	2008-12-31			
16th prior year	2007-12-31			
17th prior year	2006-12-31			
18th prior year	2005-12-31			
19th prior year	2004-12-31			
20th prior year	2003-12-31			
21st prior year*	2002-12-31			
Total (to line A)				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes **(Note 1) multiplied** by 75 % 727,064 2A

Taxable capital gains arising in respect of gifts of capital property included in Part 1 **(Note 2)** 225

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) 227

The amount of the recapture of capital cost allowance in respect of charitable donations 230

Proceeds of disposition, **less** outlays and expenses **(Note 2)** 2B

Capital cost **(Note 2)** 2C

Amount 2B or 2C, whichever is less 235

Amount on line 230 or 235, whichever is less 2D

Subtotal (**add** lines 225, 227, and amount 2D) 2E

Amount 2E **multiplied** by 25 % 2F

Subtotal (amount 2A **plus** amount 2F) 727,064 2G

Maximum allowable deduction for charitable donations
(enter amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is the least) 6,751 2H

Note 1: For credit unions, this amount is before the deduction of bonus interest payments and payments pursuant to allocations in proportion to borrowing made by the credit union that is otherwise deductible under subsection 137(2).

Note 2: This amount must be prorated by the following calculation: eligible amount of the gift **divided** by the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

	Line	Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A	
Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440			
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450			
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410			
Subtotal (line 450 **plus** line 410)			3B	
Subtotal (line 440 **plus** amount 3B)			3C	
Adjustment for an acquisition of control	455			
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460			
Subtotal (line 455 **plus** line 460)			3D	
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480			

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2022-12-31			
2nd prior year	2021-12-31			
3rd prior year	2020-12-31			
4th prior year	2019-12-31			
5th prior year	2018-12-31			
6th prior year*	2017-12-31			
7th prior year	2016-12-31			
8th prior year	2015-12-31			
9th prior year	2014-12-31			
10th prior year	2013-12-31			
11th prior year	2012-12-31			
12th prior year	2011-12-31			
13th prior year	2010-12-31			
14th prior year	2009-12-31			
15th prior year	2008-12-31			
16th prior year	2007-12-31			
17th prior year	2006-12-31			
18th prior year	2005-12-31			
19th prior year	2004-12-31			
20th prior year	2003-12-31			
21st prior year*	2002-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1)	520				
Subtotal (line 550 **plus** line 520)			4B		
Subtotal (line 540 **plus** amount 4B)			4C		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date

Year of origin:		Federal	Québec	Alberta
1st prior year	2022-12-31			
2nd prior year	2021-12-31			
3rd prior year	2020-12-31			
4th prior year	2019-12-31			
5th prior year	2018-12-31			
6th prior year*	2017-12-31			
7th prior year	2016-12-31			
8th prior year	2015-12-31			
9th prior year	2014-12-31			
10th prior year	2013-12-31			
11th prior year*	2012-12-31			
12th prior year	2011-12-31			
13th prior year	2010-12-31			
14th prior year	2009-12-31			
15th prior year	2008-12-31			
16th prior year	2007-12-31			
17th prior year	2006-12-31			
18th prior year	2005-12-31			
19th prior year	2004-12-31			
20th prior year	2003-12-31			
21st prior year*	2002-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

	Line	Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	600				

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

	Line	Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			5D		
Subtotal (line 640 **plus** amount 5D)			5E		
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F) **(Note 3)**	680				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Note 3: The amount at line 680 is not available for carryforward.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2022-12-31			
2nd prior year	2021-12-31			
3rd prior year	2020-12-31			
4th prior year	2019-12-31			
5th prior year	2018-12-31			
6th prior year*	2017-12-31			
7th prior year	2016-12-31			
8th prior year	2015-12-31			
9th prior year	2014-12-31			
10th prior year	2013-12-31			
11th prior year	2012-12-31			
12th prior year	2011-12-31			
13th prior year	2010-12-31			
14th prior year	2009-12-31			
15th prior year	2008-12-31			
16th prior year	2007-12-31			
17th prior year	2006-12-31			
18th prior year	2005-12-31			
19th prior year	2004-12-31			
20th prior year	2003-12-31			
21st prior year*	2002-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2022-12-31	
2nd prior year	2021-12-31	
3rd prior year	2020-12-31	
4th prior year	2019-12-31	
5th prior year	2018-12-31	
6th prior year	2017-12-31	
7th prior year	2016-12-31	
8th prior year	2015-12-31	
9th prior year	2014-12-31	
10th prior year	2013-12-31	
11th prior year	2012-12-31	
12th prior year	2011-12-31	
13th prior year	2010-12-31	
14th prior year	2009-12-31	
15th prior year	2008-12-31	
16th prior year	2007-12-31	
17th prior year	2006-12-31	
18th prior year	2005-12-31	
19th prior year	2004-12-31	
20th prior year	2003-12-31	
21st prior year*	2002-12-31	
Total		

* These gifts expired in the current year.

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, H.1, I, I.1, I.2 and L **only if** the payer corporation is **connected**.

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1), (b), or (d) [1] 240	F1	G Eligible dividends included in column F 242	H Total taxable dividends paid by the **connected** payer corporation (line 460 in Schedule 3 for the tax year in column D) 250	H.1 Total eligible dividends paid by the **connected** payer corporation (line 465 in Schedule 3 for the tax year in column D)	I Dividend refund of the **connected** payer corporation (for tax year in column D) [2] 260
1						

	I.1 Eligible dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (amount CC from T2 return for the tax year in column D)	I.2 Additional non-eligible dividend refund of the **connected** payer corporation from its ERDTOH (amount II from T2 return for the tax year in column D)	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3% [3] 265	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3% [4] 275	L Part IV tax before deductions on taxable dividends received from **connected** corporations [5] 280
1					

Total of column L (enter amount on line 2E in Part 2) ______

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) ______ 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) ______ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) ______ 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) ______ 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) ______ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) ______ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) ______ 1G

Subtotal (amount 1F **plus** amount 1G) ______ ▶ ______ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) ______ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) ______ 1J

Subtotal (amount 1I **plus** amount 1J) ______ ▶ ______ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) ______ 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column K (and column J, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the **connected** payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column F.

5 For the purpose of calculating your eligible refundable dividend tax on hand (ERDTOH), Part IV tax on taxable dividends received from **connected** corporations (with a tax year starting after 2018) is equal to the sum of Part IV tax on eligible dividends and non-eligible dividends received from **connected** corporations to the extent that such dividends caused a dividend refund to those corporations from their ERDTOH.

Part IV tax before deductions on taxable dividends received from **connected** corporations for purposes of column L is the sum of (i) and (ii), where

(i) Part IV tax on eligible dividends received from **connected** corporations is equal to amount CC of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 465 of the **connected** payer corporation, **multiplied** by column G; and

(ii) Part IV tax on non-eligible dividends received from **connected** corporations is equal to amount II of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 470 of the **connected** payer corporation, **multiplied** by the difference between columns F and G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1)			2A	
Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43)	320			
Subtotal (amount 2A **minus** line 320)			▶	2B
Current-year non-capital loss claimed to reduce Part IV tax	330			
Non-capital losses from previous years claimed to reduce Part IV tax	335			
Current-year farm loss claimed to reduce Part IV tax	340			
Farm losses from previous years claimed to reduce Part IV tax	345			
Total losses applied against Part IV tax (total of lines 330 to 345)			2C	
Amount 2C **multiplied** by 38 1 / 3 %				2D
Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") (enter amount on line 712 of the T2 return)			360	

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1)		2E
Amount 4A from Schedule 43		2F
Part IV tax payable on taxable dividends received from connected corporations (amount 2E **minus** amount 2F, if negative enter "0") (enter at amount C on page 7 of the T2 return)		2G
Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1)		2H
Amount 4C from Schedule 43		2I
Part IV tax payable on taxable dividends received from non-connected corporations (amount 2H **minus** amount 2I, if negative enter "0") (enter at amount D on page 7 of the T2 return)		2J

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	M Name of recipient corporation with which you are connected 400	N Business number 410	O Tax year-end of recipient corporation in which the dividends in column P were received YYYYMMDD 420	P Taxable dividends paid to recipient corporations with which you are connected 430	Q Eligible dividends included in column P 440
1	City of Stratford	NR	2023-12-31	624,080	
2					
				624,080 (Total of column P)	(Total of column Q)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends included in line 450	455		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column P **plus** line 450)		460	624,080
Total eligible dividends paid in the tax year (total of column Q **plus** line 455)		465	
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)		470	624,080

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)		3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)	239,231	3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			624,080
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	624,080
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal (total of lines 510 to 540)		►	4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A)			624,080 4B

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Use this schedule if any of the following apply to your corporation during the tax year:
  - it had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - it is claiming provincial or territorial tax credits or rebates (see Part 2)
  - it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)
- All legislative references are to the federal Income Tax Regulations (the Regulations).
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Allocation of taxable income

100 ______________________ Enter the regulation that applies (402 to 413).

A Jurisdiction. (tick **yes** if your corporation had a permanent establishment in the jurisdiction during the tax year) **Note 1**		**B** Total salaries and wages paid in jurisdiction	**C** B **multiplied** by taxable income, **divided** by G	**D** Gross revenue attributable to jurisdiction	**E** D **multiplied** by taxable income, **divided** by H	**F** Allocation of taxable income (C + E x 1/2) **Note 2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes ☐	113		153		
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes ☐	119		159		
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G		169 H		

Note 1: **Permanent establishment** is defined in subsection 400(2).
Note 2: For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, complete Part 2.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
962,667		962,667	110,707

Ontario basic income tax (from Schedule 500)	270	110,707		
Ontario small business deduction (from Schedule 500)	402			
Subtotal (line 270 **minus** line 402)		110,707	110,707	5A
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal (line 276 **plus** line 277)				5B
Gross Ontario tax (amount 5A **plus** amount 5B)			110,707	5C
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario political contributions tax credit (from Schedule 525)	415			
Ontario non-refundable tax credits (total of lines 406 to 415)				5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")			110,707	5E
Ontario research and development tax credit (from Schedule 508)	416		5,402	
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")			105,305	5F
Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario community food program donation tax credit for farmers (from Schedule 2)	420			
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")			105,305	5G
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal (line 278 **plus** line 280)				5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)			105,305	5I
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	3,000		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Ontario regional opportunities investment tax credit (from Schedule 570)	472			
Ontario made manufacturing investment tax credit (from Schedule 572)	474			
Ontario refundable tax credits (total of lines 450 to 474)		3,000	3,000	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets). Include this amount on line 255.	290		102,305	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits . . . . 255 — 102,305

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the tax year with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . **105** Yes [X] No [ ]

If you answered **yes**, complete Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your corporation) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 2.

	1 Name of EPOP **110**	2 Identification number See **note 1** **115**	3 Percentage assigned under the agreement **120**
1.	Festival Hydro Inc.	899571814RC0002	90.000
2.	Festival Hydro Services Inc.	862953726RC0001	10.000
3.	Abiliti Municipal Corporation	779784321RC0001	
		Total	100.000

Immediate expensing limit allocated to the corporation (see **note 2**) **125** 1,350,000

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your corporation in column 3. If the total of column 3 is more than 100%, enter 0.

Part 2 – CCA calculation

	1 Class number See note 3 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) See note 4 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) See note 5 232	5 Adjustments and transfers See note 6 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 7 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 8 222	8 Proceeds of dispositions See note 9 207
1.	1		13,084,450						0
2.	1b		4,476,478	1,060,506					0
3.	2		1,611,967						0
4.	6		36,636						0
5.	8		906,938	36,453	36,453				0
6.	10		139,527	92,935	92,935				0
7.	12	Software		221,093	221,093				0
8.	14	CCRA contract - 25 year	318,106						0
9.	14	CCRA contract- 15 year	176,219						0
10.	14.1		511,235						0
11.	17		57,158						0
12.	43.2		209						0
13.	45		4						0
14.	46	Server, Router	330						0
15.	47		23,085,233	2,401,865					0
16.	50		25,628	290,629	290,629				0
17.	95	Smart Meters - Not in Use	293,758	26,972	26,972				0
18.	95	Transformers - Not available for use	1,308,739	175,389	175,389				0
19.	95	Software not in use	211,458	426,822	426,822				0
		Totals	46,244,073	4,732,664	1,270,293				

	1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) **234**	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See **note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) See **note 11** **236**	12 Immediate expensing See **note 12** **238**	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 See **note 13** **225**	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0") See **note 14**
1.	1			13,084,450					13,084,450	
2.	1b			5,536,984			1,060,506	1,060,506	5,536,984	
3.	2			1,611,967					1,611,967	
4.	6			36,636					36,636	
5.	8			943,391	36,453	36,453			906,938	
6.	10			232,462	92,935	92,935			139,527	
7.	12	Software		221,093	221,093		221,093	221,093	221,093	
8.	14	CCRA contract - 25 year		318,106					318,106	
9.	14	CCRA contract- 15 year		176,219					176,219	
10.	14.1			511,235					511,235	
11.	17			57,158					57,158	
12.	43.2			209					209	
13.	45			4					4	
14.	46	Server, Router		330					330	
15.	47			25,487,098			2,401,865	2,401,865	25,487,098	
16.	50			316,257	290,629	290,629			25,628	
17.	95	Smart Meters - Not in Use		320,730	26,972		26,972	26,972	320,730	
18.	95	Transformers - Not available for use		1,484,128	175,389		175,389	175,389	1,484,128	
19.	95	Software not in use		638,280	426,822		426,822	426,822	638,280	
		Totals		50,976,737	1,270,293	420,017	4,312,647	4,312,647	50,556,720	

Part 2 – CCA calculation (continued)

	1 Class number	Description	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the year (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the year (column 17 **multiplied** by the relevant factor) See **note 15**	19 UCC adjustment for property acquired during the year other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See **note 16** **224**	20 CCA rate % See **note 17** **212**	21 Recapture of CCA See **note 18** **213**	22 Terminal loss See **note 19** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) See **note 20** **217**	24 UCC at the end of the year (column 10 **minus** column 23) **220**
1.	1					4	0	0	523,378	12,561,072
2.	1b		1,060,506	530,253		6	0	0	364,034	5,172,950
3.	2					6	0	0	96,718	1,515,249
4.	6					10	0	0	3,664	32,972
5.	8					20	0	0	217,841	725,550
6.	10					30	0	0	134,793	97,669
7.	12	Software	221,093			100	0	0	221,093	
8.	14	CCRA contract - 25 year				NA	0	0	20,267	297,839
9.	14	CCRA contract- 15 year				NA	0	0	32,000	144,219
10.	14.1					5	0	0	34,542	476,693
11.	17					8	0	0	4,573	52,585
12.	43.2					50	0	0	105	104
13.	45					45	0	0	2	2
14.	46	Server, Router				30	0	0	99	231
15.	47		2,401,865	1,200,933		8	0	0	2,135,042	23,352,056
16.	50					55	0	0	304,724	11,533
17.	95	Smart Meters - Not in Use	26,972	13,486		0	0	0		320,730
18.	95	Transformers - Not available for use	175,389	87,695		0	0	0		1,484,128
19.	95	Software not in use	426,822	213,411		0	0	0		638,280
		Totals	4,312,647	2,045,778					4,092,875	46,883,862

Enter the total of column 21 on line 107 of Schedule 1.
Enter the total of column 22 on line 404 of Schedule 1.
Enter the total of column 23 on line 403 of Schedule 1.

Note 3: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6).

Note 5: A DIEP reported in column 4 is a property acquired after April 18, 2021, by a corporation that was a Canadian-controlled private corporation (CCPC) throughout the year, which became available for use in the tax year (before 2024) and was designated as such on or before the day that is 12 months after the filing-due date for the tax year to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the year in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

Note 6: Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Part 2 – CCA calculation (continued)

Note 8: Include all amounts you have repaid during the year for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the undepreciated capital cost, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter zero. The only amounts incurred before April 19, 2021, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the tax year (total of column 12) should not exceed the lesser of:

1. Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:

- $1.5 million, if you are not associated with any other EPOP in the tax year
- amount from line 125, if you are associated in the tax year with one or more EPOPs
- nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the tax year with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
- the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent tax years ending in a calendar year, if you have two or more tax years ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
- any amount allocated by the minister under subsection 1104(3.4) of the Regulations

The immediate expensing limit has to be prorated if your tax year is less than 365 days. You cannot carry forward any unused amount of the immediate expensing limit.

2. UCC of the DIEP: total of column 11

You have to maintain the CCPC status throughout the relevant tax year in order to claim the immediate expensing.

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.
Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.
Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.
See the T2 Corporation Income Tax Guide for more information.

Note 14: Include only elements from columns 6 and 7 that are not related to the DIEP.

Note 15: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use respectively before 2024 are:

- 2 1/3 for property in Classes 43.1, 54, and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 20 for additional information) and
- 0.5 for all other property that is an AIIP

Part 2 – CCA calculation (continued)

Note 16: The UCC adjustment for property acquired during the year (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56).
Include only elements from columns 6 and 7 that are not related to the DIEP.
For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 17: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 23.

Note 18: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 19: If no property is left in the class at the end of the tax year and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 20: If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot, or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Festival Hydro Services Inc.		86295 3726 RC0001	3					249,235
2.	Abiliti Municipal Corporation		77978 4321 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Post employment benefits	1,009,878		1,024,453	1,009,878	1,024,453
2	Allowance for Doubtful Accounts	171,996		187,492	171,996	187,492
3						
	Reserves from Part 2 of Schedule 13					
	Totals	1,181,874		1,211,945	1,181,874	1,211,945

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)
2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation
3 – Non-CCPC that is a **third corporation**
4 – Associated non-CCPC
5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year the agreement applies to . . . . . . **050** Year 2023

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** ☐ Yes ☒ No

	1 Name of associated corporations **100**	2 Business number of associated corporations **200**	3 Association code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	Festival Hydro Inc.	89957 1814 RC0002	1	500,000	100.0000	500,000
2	Festival Hydro Services Inc.	86295 3726 RC0001	1	500,000		
3	Abiliti Municipal Corporation	77978 4321 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (C - $10,000,000). Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

T2 SCH 23 E (19)

Canada

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
- Unless otherwise stated, all legislative references are to the federal Income Tax Act and Income Tax Regulations.
- Certain ITCs are eligible for a three-year carryback (if not deductible in the year earned) and are also eligible for a twenty-year carryforward. This does not apply to the clean economy ITCs, which are refundable tax credits.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
    - You can no longer claim the ITC for the qualified resource property expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Part 22)
    - You can no longer claim the ITC for the child care spaces expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
- Investments or expenditures for clean economy, described in sections 127.44 or 127.45, that earn an ITC are:
  - investment in carbon capture, utilization, or storage (CCUS) projects, for qualifying expenditures made after 2021 (Part 25)
  - investment in clean technology property that is acquired and that becomes available for use after March 27, 2023 (Part 24)
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see **Investment Tax Credit** in Guide T4012, T2 Corporation – Income Tax Guide.
- For more information on SR&ED, see Guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, investment means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired. See subsection 127.44(9) for similar rules for capital cost for the CCUS ITC and subsection 127.45(5) for similar rules for capital cost for the clean technology ITC.
- An ITC deducted in a tax year for a depreciable property reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use (AFU)** before a claim for an ITC can be made. See subsections 127(11.2), 127.45(4) and 248(19) for more information. The AFU rules do not apply to claims for the CCUS ITC.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures. A claimant that does not meet this reporting deadline will not be able to file Schedule 508, Ontario Research and Development Tax Credit, and Schedule 566, Ontario innovation Tax Credit.
- Expenditures for an apprenticeship ITC or a clean economy ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures.

Detailed information (continued)

- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms). See section 127.47 for rules that apply to partnerships for the clean economy ITCs generally. For more information on partnership allocations for CCUS ITC, see subsection 127.44(11), and for clean technology ITC, subsection 127.45(8).
- For tax purposes, Canada includes the **exclusive economic zone** of Canada as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone. For the clean technology ITC, Canada includes the exclusive economic zone of Canada only for property that is described in subparagraph d(v) or (xiv) of Class 43.1 in Schedule II of the Regulations.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Certain qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures and percentages

Investments	Specified percentage
Qualified property and qualified resource property (Part 5)	
Qualified property acquired primarily for use in Atlantic Canada	10 %
Expenditures	
SR&ED (Part 11)	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
Apprenticeship job creation (Part 19)	
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
Clean economy ITCs	
To qualify for the investment tax credit rates below, corporations must elect (in prescribed form) to meet certain labour requirements – prevailing wage requirements and apprenticeship requirements. They must also attest (in prescribed form) to have met these requirements. Otherwise, the credit rate will be reduced by 10 percentage points.	
Clean technology	
If you invested in clean technology property that is acquired and that becomes available for use:	
after March 27, 2023, and before 2034	30%
after 2033 and before 2035	15%
CCUS (Part 25)	
If you incurred qualified carbon capture expenditures to capture carbon directly from ambient air:	
after 2021 and before 2031	60%
after 2030 and before 2041	30%
If you incurred qualified carbon capture expenditures to capture carbon other than directly from ambient air:	
after 2021 and before 2031	50%
after 2030 and before 2041	25%
If you incurred qualified expenditures for carbon transportation, use, or storage:	
after 2021 and before 2031	37.5%
after 2030 and before 2041	18.75 %

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

Part 2A – Determination of a qualifying corporation

This section does not apply to the clean economy investment tax credits.

Is the corporation a qualifying corporation? . . . . . . 101 Yes [ ] No [X]

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) . . . . . . 390 ________

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 2B – Determination of an excluded corporation – SR&ED

Is the qualifying corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . . 650 Yes [ ] No [X]

Only 40% refund will be available to a qualifying corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority

c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . . 102 Yes [ ] No [X]

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . . . ________ x 80 % = 103 ________

Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property from the current tax year

Capital cost allowance class number 105	Description of investment 110	Date available for use 115	Location used in Atlantic Canada (province) 120	Amount of investment 125

Total of investments for qualified property ________ 4A

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				5A
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)			▶	5B
ITC at the beginning of the tax year (amount 5A **minus** amount 5B)			220	
Credit transferred on an amalgamation or the wind-up of a subsidiary	230			
ITC from repayment of assistance	235			
Qualified property (amount 4A) ______ x 10 % =	240			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)			▶	5C
Total credit available (line 220 **plus** amount 5C)				5D
Credit deducted from Part I tax	260			
Credit carried back to previous years (amount 6A)		5E		
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount 5E, and line 280)			▶	5F
Credit balance before refund (amount 5D **minus** amount 5F)				5G
Refund of credit claimed on investments from qualified property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount 5G **minus** line 310)			320	

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total of lines 901 to 903 ______ 6A
Enter at amount 5E.

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property

Current-year ITCs (line 240 **plus** line 250 in Part 5)	7A
Credit balance before refund (from amount 5G)	7B
Refund (40 % of amount 7A or 7B, whichever is less)	7C

Enter amount 7C or a lesser amount on line 310 in Part 5 (also include in line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Qualified SR&ED expenditures (line 559 on Form T661)		148,931		
Contributions to agricultural organizations for SR&ED				
Deduct:				
Government assistance, non-government assistance, or contract payment				
Subtotal				
x	80 %			
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*		+		
Qualified SR&ED expenditures (line 559 on Form T661 **plus** line 103 in Part 3)*		148,931	350	148,931
Repayments made in the year (from line 560 on Form T661)			370	
Total qualified SR&ED expenditures (line 350 **plus** line 370)			380	148,931

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 Yes [X] No [ ]

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete line 398.
If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable capital employed in Canada for the previous tax year ______ **minus** $10 million.
If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million 398 ______

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation

$ 40,000,000 **minus** line 398 in Part 9 ______ 10A

Amount 10A divided by $ 40,000,000 ______ 10B

Expenditure limit for the stand-alone corporation ($ 3,000,000 **multiplied** by amount 10B)* ______ 10C

For an associated corporation

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* 400 ______

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount 10C or line 400 ______ x Number of days in the tax year 365 / 365 = ______ 10D

Your SR&ED expenditure limit for the year (enter amount 10C, line 400, or amount 10D, whichever applies) 410 ______

* Amount 10C or line 400 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x	35 %	=		11A
Line 350 **minus** line 410 (if negative, enter "0")	430	148,931	x	15 %	=	22,340	11B

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . ________

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC**	460		x	35 %	=		11C
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred before 2015	480		x	20 %	=		11D
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred after 2014	490		x	15 %	=		11E
Subtotal (total of amounts 11C to 11E)						▶	11F
Current-year SR&ED ITC (total of amounts 11A, 11B, and 11F; enter on line 540 in Part 12)						22,340	11G

* For corporations that are not CCPCs, enter "0" for amount 11A.

** If you were a CCPC, this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				12A
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)			▶	12B
ITC at the beginning of the tax year (amount 12A **minus** amount 12B)			520	
Credit transferred on an amalgamation or the wind-up of a subsidiary	530			
Total current-year credit (from amount 11G)	540	22,340		
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		22,340	▶ 22,340	12C
Total credit available (line 520 **plus** amount 12C)			22,340	12D
Credit deducted from Part I tax	560	22,340		
Credit carried back to previous years (amount 13A)		12E		
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount 12E, and line 580)		22,340	▶ 22,340	12F
Credit balance before refund (amount 12D **minus** amount 12F)				12G
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED (amount 12G **minus** line 610)			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year Month Day			
1st previous tax year		Credit to be applied	911	
2nd previous tax year		Credit to be applied	912	
3rd previous tax year		Credit to be applied	913	

Total of lines 911 to 913 ____ 13A
Enter at amount 12E.

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part if you are a qualifying corporation as determined on line 101 in Part 2A.*

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount 11F) ____ 14A

Refundable credits (amount 14A or amount 12G, whichever is less) ____ 14B

Amount 14B or amount 11A, whichever is less ____ 14C

Net amount (amount 14B **minus** amount 14C; if negative, enter "0") ____ 14D

Amount 14D **multiplied** by 40 % ____ 14E

Amount 14C ____ 14F

Refund of ITC (amount 14E **plus** amount 14F – enter this, or a lesser amount, on line 610 in Part 12) ____ 14G

Include the total of line 310 in Part 5 and line 610 in Part 12 in line 780 of the T2 return.

* If you are also an excluded corporation, as determined in Part 2B, amount 14B must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount 14G.

Part 15 – Refund of ITC for CCPCs that are neither qualifying nor excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying corporation as determined on line 101 in Part 2A or an excluded corporation as determined on line 650 in Part 2B.

Credit balance before refund (amount 12G) ____ 15A

Refund of ITC (amount 15A or amount 11A, whichever is less) ____ 15B

Enter amount 15B, or a lesser amount, on line 610 in Part 12 and also include it in line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal ______ 16A
Enter at amount 17A.

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount 16B.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (total of column F) ______ 16B
Enter at amount 17B.

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** ______
Enter at amount 17C.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount 16A		17A
Recaptured ITC from calculation 2, amount 16B		17B
Recaptured ITC from calculation 3, line 760 in Part 16		17C
Total recapture of SR&ED investment tax credit (total of amounts 17A to 17C) Enter at amount 26A.		17D

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year				18A
Credit deemed as a remittance of co-op corporations	841			
Credit expired	845			
Subtotal (line 841 **plus** line 845)		►		18B
ITC at the beginning of the tax year (amount 18A **minus** amount 18B)		850		
Credit transferred on an amalgamation or the wind-up of a subsidiary		860		
Total credit available (line 850 **plus** line 860)				18C
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year		885		
ITC closing balance from pre-production mining expenditures (amount 18C **minus** line 885)		890		

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 Yes ☐ No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	[redacted]	Powerline Technician	59,846	5,985	2,000

Total current-year credit (total of column E) 2,000 19A
Enter on line 640 in Part 20.

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				20A
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)				20B
ITC at the beginning of the tax year (amount 20A **minus** amount 20B)	625			
Credit transferred on an amalgamation or the wind-up of a subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (amount 19A)	640	2,000		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		2,000	2,000	20C
Total credit available (line 625 **plus** amount 20C)			2,000	20D
Credit deducted from Part I tax	660	2,000		
Credit carried back to previous years (amount 21A)				20E
Subtotal (line 660 **plus** amount 20E)		2,000	2,000	20F
ITC closing balance from apprenticeship job creation expenditures (amount 20D **minus** amount 20F)	690			

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	

Total of lines 931 to 933 21A
Enter at amount 20E.

Child Care Spaces

Part 22 – Account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			22A
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal (line 765 **plus** line 770)		▶	22B
ITC at the beginning of the tax year (amount 22A **minus** amount 22B)	775		
Credit transferred on an amalgamation or the wind-up of a subsidiary	777		
Credit allocated from a partnership	782		
Subtotal (line 777 **plus** line 782)		▶	22C
Total credit available (line 775 **plus** amount 22C)			22D
Credit deducted from Part I tax	785		
ITC closing balance from child care spaces expenditures (amount 22D **minus** line 785)	790		

Recapture – Child Care Spaces

Part 23 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be added to the taxpayer's tax otherwise payable under Part I of the Act if at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an eligible expenditure for the child care space is
  - disposed of or leased to a lessee
  - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))	792	
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:		
The amount that can reasonably be considered to have been included in the original ITC	795	
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797	
Amount from line 795 or line 797, whichever is less		23A

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 22. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC	799	
Total recapture of child care spaces investment tax credit (total of line 792, amount 23A, and line 799)		23B

Enter at amount 26B.

Clean technology

Part 24 – Clean technology ITC

Clean technology ITC	155		

Include in line 780 of the T2 return.

Carbon Capture, Utilization, and Storage

Part 25 – Carbon capture, utilization, and storage ITC

Carbon capture, utilization, and storage ITC	200		

Include in line 780 of the T2 return.

Summary of Investment Tax Credits

Part 26 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount 17D)		26A
Recaptured child care spaces ITC (amount 23B)		26B
Total recapture of investment tax credit (amount 26A **plus** amount 26B) Enter on line 602 of the T2 return.		26C

Part 27 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5)		27A
ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12)	22,340	27B
ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18)		27C
ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20)	2,000	27D
ITC from child care space expenditures deducted from Part I tax (line 785 in Part 22)		27E
Total ITC deducted from Part I tax (total of amounts 27A to 27E) Enter on line 652 of the T2 return.	24,340	27F

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	2,000	2,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2022-12-31				
2021-12-31				
2020-12-31				
2019-12-31				
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				*
Total				

B+C+D+G **Total ITC utilized** 2,000

* The **ITC end of year** includes the amount of ITC expired from the 20th preceding year. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	22,340	22,340			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2022-12-31				
2021-12-31				
2020-12-31				
2019-12-31				
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				*
Total				

B+C+D+G **Total ITC utilized** 22,340

* The **ITC end of year** includes the amount of ITC expired from the 20th preceding year. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	3,187,561	
Capital stock (or members' contributions if incorporated without share capital)	103	15,568,388	
Retained earnings	104	19,746,723	
Contributed surplus	105		
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	34,116,087	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		72,618,759 ▶	72,618,759 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  a) those lines applied to partnerships in the same manner that they apply to corporations, and
  b) those amounts were computed without reference to amounts owing by the partnership
    (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)		72,618,759	A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124) ▶			B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	72,618,759	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		72,618,759	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	72,618,759	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 72,618,759 x Taxable income earned in Canada **610** 962,667 / Taxable income 962,667 = **Taxable capital employed in Canada** **690** 72,618,759

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount
Current portion of long-term debt		18,850,364 00
Due to City	+	635,845 00
Long-term debt	+	9,061,648 00
Bank indebtedness per F/S	+	3,679,961 00
Customer deposits - current	+	1,256,618 00
Customer deposits - long-term	+	631,651 00
	Total	34,116,087 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in calculating income for the

Description	Operator (Note)	Amount	
Employee future benefits		1,024,453	00
SWAP	-	454,755	00
Deferred tax liability	+	2,617,863	00
	+		
	Total	3,187,561	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 50

Shareholder Information

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number (business number, partnership account number, social insurance number or trust number) per shareholder.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business number or partnership account number (9 digits, 2 letters, and 4 digits. If not registered, enter "**NR**") 200	Social insurance number (9 digits) 300	Trust number (T followed by 8 digits) 350	Percentage common shares 400	Percentage preferred shares 500
1	Corporation of the City of Stratford	NR			100.000	100.000
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		624,080		
Total taxable dividends paid in the tax year	100	624,080		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	15,543,910
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180	
Subtotal (amount A **minus** line 180)				B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)			190	

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)				C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280	
Subtotal (amount C **minus** line 280)				D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)			290	

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Use this schedule if your corporation had a **permanent establishment** (as defined in section 400 of the federal Income Tax Regulations) in Ontario at any time in the tax year and had Ontario taxable income in the tax year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income **(Note 1)**	962,667	1A
Ontario basic rate of tax for the year	11.5 %	1B
Ontario basic income tax (amount 1A **multiplied** by amount 1B) **(Note 2)**	110,707	1C

Note 1: If your corporation had a permanent establishment only in Ontario, enter the amount from line 360, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Note 2: If your corporation had a permanent establishment in more than one jurisdiction or is claiming an Ontario tax credit in addition to Ontario basic income tax, Ontario corporate minimum tax, or Ontario special additional tax on life insurance corporations payable, enter amount 1C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if your corporation claimed the federal small business deduction under subsection 125(1).

Line 400 of the T2 return		969,418	2A	
Line 405 of the T2 return		962,667	2B	
Line 410 of the T2 return	500,000	2C		
Line 415 of the T2 return	139,314	2D		

Business limit reduction for tax years starting before April 7, 2022

Amount 2C ______ x Amount 2D ______ / 11,250 = ______ 2E

Business limit reduction for tax years starting after April 6, 2022

Amount 2C 500,000 x Amount 2D 139,314 / 90,000 = 773,967 2F

Amount 2E or amount 2F, whichever applies	773,967	2G		
Line 515 of the T2 return		2H		
Subtotal (amount 2C **minus** amount 2G **minus** amount 2H)		▶	2I	
Amount 2A, 2B or 2I whichever is the least			▶	2J

Ontario domestic factor (ODF): Taxable income for Ontario **(Note 3)** 962,667.00 / Taxable income for all provinces **(Note 4)** 962,667 = 1.00000 2K

Amount 2J **multiplied** by amount 2K		2L
Ontario taxable income (amount 1A)	962,667	2M
Ontario small business income (amount 2L or 2M, whichever is less)	▶	2N

Ontario small business deduction for the year

Amount 2N ______ x 8.3 % = ______ 2O

Enter Ontario small business deduction for the year (amount 2O) on line 402 of Schedule 5.

Note 3: Enter amount 1A.

Note 4: Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 3 – Ontario adjusted small business income

Complete this part if your corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (amount 1A or 2J, whichever is the least) . . . . ______ 3A

Enter amount 3A at amount 4B in Part 4 of this schedule or at amount 2E in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 2C of Schedule 17 . . . . ______ 4A

Ontario adjusted small business income (amount 3A) . . . . ______ 4B

Subtotal (amount 4A **minus** amount 4B) (if negative, enter "0") ______ ▶ ______ 4C

Amount 4C ______ x 8.3 % = ... ______ 4D

Ontario domestic factor (amount 2K) 1.00000 4E

Ontario credit union tax reduction (amount 4D **multiplied** by amount 4E) . . . . ______ 4F

Enter amount 4F on line 410 of Schedule 5.

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Schedule 508

Ontario Research and Development Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC earned in the tax year to reduce Ontario corporate income tax payable in any of the three previous tax years;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - add an ORDTC transferred after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
  - 4.5% for tax years that end before June 1, 2016;
  - 3.5% for tax years that start after May 31, 2016; and
  - prorated for a tax year that ends on or after June 1, 2016, and includes May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

Part 1 – Ontario SR&ED expenditure pool

	Line	Amount		Line	Amount	
Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	154,333	A			
Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B			
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		154,333	C			
Eligible expenditures transferred to the corporation by another corporation	110		D			
Subtotal (amount C **plus** amount D)		154,333	▶		154,333	E
Eligible expenditures the corporation transferred to another corporation				115		F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")				120	154,333	G

Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 . . . . **210** ________ x 4.5 % = **215** ________ H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

Number of days in the tax year before June 1, 2016	240	152	x	4.5 %	=	1.8689 %	1
Number of days in the tax year	241	366					
Number of days in the tax year after May 31, 2016	242	214	x	3.5 %	=	2.0464 %	2
Number of days in the tax year	243	366					

Subtotal (percentage 1 **plus** percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 . . . . . . **211** ________ x percentage 3 3.9153 % = **216** ________ I

Part 2 – Eligible repayments (continued)

Repayments for tax years that start after May 31, 2016	212		x 3.5 %	= 217		J
Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014	220	x 1 / 4 =	x 4.5 %	= 225		K
Eligible repayments (total of amounts H to K)				229		L

Part 3 – Calculation of the current part of the ORDTC

For tax years that end before June 1, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)		x 4.5 %	= 200		M
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *			205		N
Eligible repayments (amount L in Part 2)					O
Current part of the ORDTC for tax years that end before June 1, 2016 (total of amounts M to O)			230		P

For a tax year that ends on or after June 1, 2016, and includes May 31, 2016

Number of days in the tax year before June 1, 2016 / Number of days in the tax year ______ x 4.5 % = ______ % 4

Number of days in the tax year after May 31, 2016 / Number of days in the tax year ______ x 3.5 % = ______ % 5

Subtotal (percentage 4 **plus** percentage 5) ______ % 6

Ontario SR&ED expenditure pool (amount G in Part 1)		x percentage 6 ______ %	= 201		Q
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *			206		R
Eligible repayments (amount L in Part 2)					S
Part of the ORDTC for a tax year that ends on or after June 1, 2016, and includes May 31, 2016 (total of amounts Q to S)			231		T

For tax years that start after May 31, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)	154,333	x 3.5 %	= 202	5,402	U
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *			207		V
Eligible repayments (amount L in Part 2)					W
The ORDTC for tax years that start after May 31, 2016 (total of amounts U to W)			232	5,402	X

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year				Y
ORDTC expired after 20 tax years		300		Z
ORDTC at the beginning of the tax year (amount Y **minus** amount Z)		305		AA
ORDTC transferred to the corporation on amalgamation or windup		310		BB
Current part of ORDTC (amount P, T or X in Part 3 whichever applies)	5,402 CC			

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Waiver of the current part of the ORDTC	320	DD			
Subtotal (amount CC **minus** amount DD)		5,402 ▶	5,402 EE		
ORDTC available for deduction (total of amounts AA, BB and EE)			5,402 ▶	5,402 FF	
ORDTC claimed ** (Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			5,402 GG		
ORDTC carried back to previous tax years (from Part 5)			HH		
Subtotal (amount GG **plus** amount HH)			5,402 ▶	5,402 II	
ORDTC balance at the end of the tax year (amount FF **minus** amount II)			325	JJ	

** This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount FF); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 on page 5 of Schedule 5).

Part 5 – Request for carryback of tax credit

	Year / Month / Day			
1st previous tax year	2022-12-31	Credit to be applied	901	
2nd previous tax year	2021-12-31	Credit to be applied	902	
3rd previous tax year	2020-12-31	Credit to be applied	903	

Total (total of amount 901 to 903)(enter at amount HH in Part 4)

Part 6 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from previous tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
2003-12-31	
2004-12-31	
2005-12-31	
2006-12-31	
2007-12-31	
2008-12-31	
2009-12-31	
2010-12-31	
2011-12-31	
2012-12-31	
2013-12-31	
2014-12-31	
2015-12-31	
2016-12-31	
2017-12-31	
2018-12-31	
2019-12-31	
2020-12-31	
2021-12-31	
2022-12-31	
Current tax year 2023-12-31	

Total (equals line 325 in Part 4) ______

The amount available from the 20th previous tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 7 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate *** of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

Complete the columns for each disposition for which a recapture applies, using the calculation formats below.

*** Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – Complete this part If you meet all of the above conditions

	KK Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	LL Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	MM Amount from column 700 or 710, whichever is less
1.			

Total of column MM (enter at amount WW in Part 8) ______ NN

Part 7 – Calculation of a recapture of ORDTC (continued)

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

	OO Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	PP Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	QQ Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	RR Amount determined by the formula (OO x PP) - QQ (using the columns above)	SS Federal ITC earned by the transferee for the qualified expenditure that was transferred 750	TT Amount from column RR or SS, whichever is less
1.			

Total of column TT (enter at amount XX in Part 8) ______ UU

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter at amount ZZ in Part 8) . . . . 760 ______ VV

Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount NN from Part 7) . . . . ______ WW

Recaptured federal ITC for Calculation 2 (amount UU from Part 7) . . . . ______ XX

Amount WW **plus** amount XX . . . . ______ x 23.56 % = ______ YY

Corporate partner's share of the excess of ORDTC for Calculation 3 (amount VV from Part 7) . . . . ______ ZZ

Recapture of ORDTC (amount YY **plus** amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5) . . . . ______ AAA

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Total expenditures for SR&ED		138,164	
Add			
• payment of prior years' unpaid expenses (other than salary or wages)	+		
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	32,094	
• other additions	+		
Subtotal	=	170,258	
Less			
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–		
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–		
• 20% of contract expenditures for SR&ED performed on your behalf	–	15,925	
• prescribed expenditures not allowed by regulations	–		
• other deductions	–		
• non-arm's length transactions			
– expenditures for non-arm's length SR&ED contracts	–		
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		
Total	=	154,333	I

Enter amount I on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	87,227,970
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	2,714,693
Total assets (total of lines 112 to 116)		89,942,663
Total revenue of the corporation for the tax year **	142	76,965,130
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	1,409,603
Total revenue (total of lines 142 to 146)		78,374,733

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	1,790,160
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	493,822		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281 SWAP	282	330,131		
283	284			
Subtotal		823,953		823,953 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	2,614,113

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

*** Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) . . . **515** ______

Deduct:

CMT loss available (amount R from Part 7) . . . ______

Minus: Adjustment for an acquisition of control * . . . **518** ______

Adjusted CMT loss available . . . ______ ▶ ______ C

Net income subject to CMT calculation (if negative, enter "0") . . . **520** ______

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 365) x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = ______ 2

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

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

Deduct:

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

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

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) . . . 105,305

Net CMT payable (if negative, enter "0") . . . ______ E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

**** Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		105,305	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)	2				
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)	3				
Gross SAT (line 460 from Part 6 of Schedule 512)	4				
The **greater** of amounts 3 and 4	5				
Deduct: line 2 or line 5, whichever applies:			6		
Subtotal (if negative, enter "0")		105,305	▶	105,305	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		105,305			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		3,000			
Subtotal (if negative, enter "0")		102,305	▶	102,305	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ► 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

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

Name of corporation	Business Number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return*.

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Festival Hydro Services Inc.	86295 3726 RC0001	2,714,692	1,409,603
2	Abiliti Municipal Corporation	77978 4321 RC0001	1	0
		Total	450 2,714,693	550 1,409,603

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Festival Hydro Inc.	89957 1814 RC0002	2023-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: Alyson Conrad	**120** Telephone number including area code: (519) 271-4700

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 1,000,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300} \text{ minus } \$400{,}000}{\$200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \text{ minus } \$400{,}000}{\$200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Conestoga College	Powerline Technician
2.		

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	[redacted]	2023-05-08	2023-09-01
2.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	14,576	25.000 %		17
2.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,644	3,000	3,000		3,000
2.					

Ontario co-operative education tax credit (total of amounts in column K) **500** 3,000 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = ... ________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Attachment 5

9-Staff-46 – 2023 Acct 1592 In-Depth - AIIP

UCC Calc.

		2017 Ending	2018 (without impact of acelerated CCA)						2017 Ending	2018 with accelerated CCA						Impact of Accelerated CCA	Tax Variance
			Additions	Adjustments	Disposals	1/2 Year Rule	CCA			Additions	Adjustments	Disposals	1/2 Year Rule	CCA			
1	4%	16,047,200				-	641,888	15,405,312	16,047,200				-	641,888	15,405,312	-	
1b	6%	4,725,438	52,338			26,169	285,096	4,492,680	4,725,438	52,338			26,169	286,032	4,491,744	936	
2	6%	2,196,427				-	131,786	2,064,641	2,196,427				-	131,786	2,064,641	-	
6	10%	62,045				-	6,205	55,841	62,045				-	6,205	55,841	-	
8	20%	1,364,070	428,081			214,041	315,622	1,476,529	1,364,070	428,081			214,041	326,191	1,465,960	10,569	
10	30%	365,291	334,227		3,540	165,344	159,190	536,788	365,291	334,227		3,540	165,344	159,190	536,788	-	
12	100%	141,192	178,912			89,456	230,648	89,456	141,192	178,912			89,456	256,002	64,102	25,354	
14	25 yrs	419,441				-	20,267	399,174	419,441				-	20,267	399,174	-	
14	15 yrs	336,219				-	32,000	304,219	336,219				-	32,000	304,219	-	
17	8%	86,723				-	6,938	79,785	86,723				-	6,938	79,785	-	
43.2	50%	6,713				-	3,357	3,357	6,713				-	3,357	3,357	-	
45	45%	72				-	32	40	72				-	32	40	-	
46	30%	1,967				-	590	1,377	1,967				-	590	1,377	-	
47	8%	22,200,849	2,070,925		4,500	1,035,463	1,858,905	22,408,369	22,200,849	2,070,925		4,500	1,033,213	1,888,886	22,378,388	29,981	
50	55%	126,635	94,549			47,275	95,650	125,534	126,635	94,549			47,275	100,838	120,346	5,188	
14.1	5%	645,434	75,196			37,598	34,152	686,478	645,434	75,196			37,598	47,061	673,569	12,909	
meters not in use (Inventory)		183,470	200,793		183,470		-	200,793	183,470	200,793		183,470		-	200,793		
transformer stock (Inventory)	0%	1,225,521	1,224,900		1,225,521		-	1,224,900	1,225,521	1,224,900		1,225,521		-	1,224,900		
		50,134,707	**4,659,921**	**-**	**1,417,031**	**1,615,344**	**3,822,326**	**49,555,271**	**50,134,707**	**4,659,921**	**-**	**1,417,031**	**1,613,094**	**3,907,262**	**49,470,335**		
									Agrees to T2					Agrees to T2		84,936.74	22,508.23

		2018 Ending	2019 (without impact of accelerated CCA)						2018 Ending	2019 (with impact of accelerated CCA)							
			Additions	Adjustments	Disposals	1/2 year Rule	CCA Calc	Ending UCC		Additions	Adjustments	Disposals	1/2 year Rule	CCA Calc	Ending UCC		
1	4%	15,405,312				-	616,212	14,789,100	15,405,312				-	616,212	14,789,100	-	
1b	6%	4,492,680	223,823			111,912	276,275	4,440,227	4,491,744	223,823			111,912	289,649	4,425,918	13,373	
2	6%	2,064,641				-	123,878	1,940,763	2,064,641				-	123,878	1,940,763	-	
6	10%	55,841				-	5,584	50,256	55,841				-	5,584	50,256	-	
8	20%	1,476,529	405,907			202,954	335,896	1,546,539	1,465,960	405,907			202,954	414,964	1,456,903	79,068	
10	30%	536,788	56,425			28,213	169,500	423,713	536,788	56,425			28,213	186,428	406,785	16,928	
12	100%	89,456	253,649			126,825	216,281	126,825	64,102	253,649			126,825	317,751	-	101,471	
14	25 yrs	399,174				-	20,267	378,907	399,174				-	20,267	378,907	-	
14	15 yrs	304,219				-	32,000	272,219	304,219				-	32,000	272,219	-	
17	8%	79,785				-	6,383	73,402	79,785				-	6,383	73,402	-	
43.2	50%	3,357				-	1,678	1,678	3,357				-	1,678	1,678	-	
45	45%	40				-	18	22	40				-	18	22	-	
46	30%	1,377				-	413	964	1,377				-	413	964	-	
47	8%	22,408,369	1,996,642			998,321	1,872,535	22,532,476	22,378,388	1,996,642			998,321	2,029,868	22,345,162	157,333	
50	55%	125,534	75,790			37,895	89,886	111,438	120,346	75,790			37,895	128,717	67,419	38,831	
14.1	5%	686,478	3,150			1,575	34,403	655,226	673,569	3,150			1,575	45,920	630,799	11,517	
meters not in use (Inventory)		200,793	379,927		200,793			379,927	200,793	379,927		200,793			379,927		
transformer stock (Inventory)	0%	1,224,900	1,187,486		1,224,900			1,187,486	1,224,900	1,187,486		1,224,900			1,187,486		
		49,555,271	**4,582,799**	**-**	**1,425,693**	**1,507,693**	**3,801,210**	**48,911,167**	**49,470,335**	**4,582,799**	**-**	**1,425,693**	**1,507,693**	**4,219,730**	**48,407,711**		
									Agrees to T2					Agrees to T2		418,520.10	110,907.83

		2019 Ending	2020 (without impact of accelerated CCA)						2019 Ending	2020 (with impact of accelerated CCA)							
			Additions	Adjustments	Disposals	1/2 year Rule	CCA Calc	Ending UCC		Additions	Adjustments	Disposals	1/2 Year Rule	CCA (calc)			
1	4%	14,789,100				-	591,564	14,197,536	14,789,100				-	591,564	14,197,536	-	
1b	6%	4,440,227	156,731			78,366	271,116	4,325,843	4,425,918	156,731			78,366	279,661	4,302,988	8,545	
2	6%	1,940,763				-	116,446	1,824,317	1,940,763				-	116,446	1,824,317	-	
6	10%	50,256				-	5,026	45,231	50,256				-	5,026	45,231	-	
8	20%	1,546,539	323,963			161,982	341,704	1,528,798	1,456,903	323,963			161,982	388,569	1,392,296	46,865	
10	30%	423,713				-	127,114	296,599	406,785				-	122,036	284,750	(5,078)	
12	100%	126,825	97,425			48,713	175,537	48,713	-	97,425			48,713	97,425	-	(78,112)	
14	25 yrs	378,907				-	20,267	358,640	378,907				-	20,267	358,640	-	
14	15 yrs	272,219				-	32,000	240,219	272,219				-	32,000	240,219	-	
17	8%	73,402				-	5,872	67,530	73,402				-	5,872	67,530	-	
43.2	50%	1,678				-	839	839	1,678				-	839	839	-	
45	45%	22				-	10	12	22				-	10	12	-	
46	30%	964				-	289	675	964				-	289	675	-	
47	8%	22,532,476	1,935,140			967,570	1,880,004	22,587,612	22,329,068	1,935,140			967,570	2,018,542	22,245,666	138,539	
50	55%	111,438	52,039			26,020	75,602	87,875	67,419	52,039			26,020	80,013	39,445	4,411	
14.1	5%	655,226				-	32,761	622,464	630,799				-	42,705	588,094	9,943	
meters not in use (Inventory)		379,927	387,837		379,927			387,837	379,927	387,837		379,927		-	387,837		
transformer stock (Inventory)	0%	1,187,486	1,233,371		1,187,486			1,233,371	1,187,486	1,233,371		1,187,486		-	1,233,371		
		48,911,167	**4,186,506**	**-**	**1,567,413**	**1,282,649**	**3,676,150**	**47,854,111**	**48,391,617**	**4,186,506**	**-**	**1,567,413**	**1,282,649**	**3,801,263**	**47,209,446**		
									Agrees to T2					Agrees to T2		125,113.37	33,155.04

		2020 Ending	2021 (without impact of accelerated CCA)						2020 Ending	2021 (with impact of accelerated CCA)							
			Additions	Adjustments	Disposals	1/2 year Rule	CCA Calc	Ending UCC		Additions	Adjustments	Disposals	1/2 Year Rule	CCA (calc)			
1	4%	14,197,536				-	567,901	13,629,634	14,197,536				-	567,901	13,629,634	-	
1b	6%	4,325,843	408,325			204,163	271,800	4,462,367	4,302,988	408,325			204,163	294,929	4,416,385	23,128	
2	6%	1,824,317				-	109,459	1,714,858	1,824,317				-	109,459	1,714,858	-	
6	10%	45,231				-	4,523	40,708	45,231				-	4,523	40,708	-	
8	20%	1,528,798	215,805			107,903	327,340	1,417,263	1,392,296	215,805			107,903	474,428	1,133,673	147,088	
10	30%	296,599	16,511			8,256	91,456	221,654	284,750	16,511			8,256	101,936	199,325	10,480	
12	100%	48,713	66,063			33,032	81,744	33,032	-	66,063				66,063	-	(15,681)	
14	25 yrs	358,640				-	20,267	338,373	358,640				-	20,267	338,373	-	
14	15 yrs	240,219				-	32,000	208,219	240,219				-	32,000	208,219	-	
17	8%	67,530				-	5,402	62,128	67,530				-	5,402	62,128	-	
43.2	50%	839				-	420	420	839				-	420	420	-	
45	45%	12				-	5	7	12				-	5	7	-	
46	30%	675				-	202	472	675				-	202	472	-	
47	8%	22,587,612	2,310,647			1,155,324	1,899,435	22,998,824	22,245,666	2,310,647			1,155,324	2,056,931	22,499,382	157,496	
50	55%	87,875	275,021			137,511	123,962	238,934	39,445	275,021			112,006	257,514	56,952	133,552	
14.1	5%	622,464				-	31,123	591,341	588,094				-	39,788	548,306	8,665	
meters not in use (Inventory)		387,837	366,392		200,793			553,436	387,837	366,392		387,837		-	366,392		
transformer stock (Inventory)	0%	1,233,371	1,348,500		1,224,900			1,356,971	1,233,371	1,348,500		1,233,371		-	1,348,500		
		47,854,111	**5,007,264**	**-**	**1,425,693**	**1,646,186**	**3,567,041**	**47,868,640**	**47,209,446**	**5,007,264**	**-**	**1,621,208**	**1,587,650**	**4,031,769**	**46,563,734**		
									Agrees to T2					Agrees to T2		464,727.51	123,152.79

		2021 Ending	2022 (without impact of accelerated CCA)						2021 Ending	2022 (with impact of accelerated CCA)							
			Additions	Adjustments	Disposals	1/2 year Rule	CCA Calc	Ending UCC		Additions	Adjustments	Disposals	1/2 Year Rule	CCA (calc)			
1	4%	13,629,634				-	545,185	13,084,449	13,629,634				-	545,185	13,084,449	-	
1b	6%	4,462,367	357,228			178,614	278,459	4,541,136	4,416,385	357,228			178,614	297,134	4,476,479	18,675	
2	6%	1,714,858				-	102,891	1,611,967	1,714,858				-	102,891	1,611,967	-	
6	10%	40,708				-	4,071	36,637	40,708				-	4,071	36,637	-	
8	20%	1,417,263	70,439			35,220	290,497	1,197,206	1,133,673	70,439			35,220	297,174	906,938	6,677	
10	30%	221,654	68,635			34,318	76,791	213,497	199,325	68,635			34,318	128,432	139,528	51,641	
12	100%	33,032	14,427			7,214	40,245	7,214	-	14,427			7,214	14,427	-	(25,818)	
14	25 yrs	338,373				-	20,267	318,106	338,373				-	20,267	318,106	-	
14	15 yrs	208,219				-	32,000	176,219	208,219				-	32,000	176,219	-	
17	8%	62,128				-	4,970	57,158	62,128				-	4,970	57,158	-	
43.2	50%	420				-	210	210	420				-	210	210	-	
45	45%	7				-	3	4	7				-	3	4	-	
46	30%	472				-	142	331	472				-	142	331	-	
47	8%	22,998,824	2,711,138			1,355,569	1,948,351	23,761,611	22,499,382	2,711,138			1,355,569	2,125,287	23,085,233	176,936	
50	55%	238,934	176,461			88,231	179,941	235,455	56,952	176,461			88,231	207,785	25,628	27,844	
14.1	5%	591,341				-	29,567	561,774	548,306				-	37,071	511,235	7,504	
meters not in use (Inventory)	0%	553,436			72,634			480,802	366,392			72,634		-	293,758		
transformer stock (Inventory)	0%	1,356,971			39,761			1,317,210	1,348,500			39,761		-	1,308,739		
Software not in use	0%		211,458							211,458				-	211,458		
		47,868,640	**3,609,786**	**-**	**112,395**	**1,699,164**	**3,553,590**	**47,600,983**	**46,563,734**	**3,609,786**	**-**	**112,395**	**1,699,164**	**3,817,049**	**46,244,076**		
									Agrees to T2					Agrees to T2		263,458.93	69,816.62

		2022 Ending	2023 (without impact of accelerated CCA)						2022 Ending	2023 (with impact of accelerated CCA)							
			Additions	Adjustments	Disposals	1/2 year Rule	CCA Calc	Ending UCC		Additions	Adjustments	Disposals	1/2 Year Rule	CCA (calc)			
1	4%	13,084,449				-	523,378	12,561,071	13,084,449				-	523,378	12,561,071	-	
1b	6%	4,541,136	1,060,506			530,253	304,283	5,297,359	4,476,479	1,060,506			530,253	364,034	5,172,951	59,751	
2	6%	1,611,967				-	96,718	1,515,249	1,611,967				-	96,718	1,515,249	-	
6	10%	36,637				-	3,664	32,973	36,637				-	3,664	32,973	-	
8	20%	1,197,206	212,043			106,022	260,645	1,148,603	906,938	212,043			106,022	245,001	873,981	(15,645)	
10	30%	213,497	92,935			46,468	77,989	228,443	139,528	92,935			46,468	83,679	148,784	5,690	
12	100%	7,214	551,449			275,725	282,938	275,725	-	551,449			275,725	551,449	-	268,511	
14	25 yrs	318,106				-	20,267	297,839	318,106				-	20,267	297,839	-	
14	15 yrs	176,219				-	32,000	144,219	176,219				-	32,000	144,219	-	
17	8%	57,158				-	4,573	52,585	57,158				-	4,573	52,585	-	
43.2	50%	210				-	105	105	210				-	105	105	-	
45	45%	4				-	2	2	4				-	2	2	-	
46	30%	331				-	99	231	331				-	99	231	-	
47	8%	23,761,611	3,129,649			1,564,825	2,026,115	24,865,145	23,085,233	3,129,649			1,564,825	2,222,376	23,992,505	196,262	
50	55%	235,455	290,629			145,315	209,423	316,661	25,628	290,629			145,315	253,865	62,393	44,442	
14.1	5%	561,774				-	28,089	533,685	511,235				-	42,705	468,531	14,616	
meters not in use (Inventory)		480,802						480,802	293,758					-	293,758		
transformer stock (Inventory)	0%	1,317,210						1,317,210	1,308,739					-	1,308,739		
		47,600,983	**5,337,211**	**-**	**-**	**2,668,606**	**3,870,288**	**49,067,907**	**46,032,618**	**5,337,211**	**-**	**-**	**2,668,606**	**4,443,914**	**46,925,915**		
									Agrees to T2					Agrees to T2		573,626.14	152,010.93

Total 1592 Variance **511,551.44**

Festival Hydro Inc
Comparison using ACTUAL additions
Account 1592 JE -- December 31, 2023

2018 No AIIP

Class No. [200]	2 UCC BOY	3 Additions	3.1 DIEP	4 Adjustments	5 Proceeds*	6 UCC	7 Half Year Rule	9 Rate %	10 Recapture	11 Terminal Loss	12 CCA	13 UCC EOY	CCA As Filed	Difference
1	16,047,200.00					16,047,200	-	4%	-	-	641,888	15,405,312	641,888	-
1b	4,725,438.00	52,338.00				4,777,776	26,169	6%	-	-	285,096	4,492,680	286,032	(936)
2	2,196,427.00					2,196,427	-	6%	-	-	131,786	2,064,641	131,786	-
6	62,045.00					62,045	-	10%	-	-	6,205	55,841	6,205	-
8	1,364,070.00	428,081.00				1,792,151	214,041	20%	-	-	315,622	1,476,529	326,191	(10,569)
10	365,291.00	334,227.00			(3,540)	695,978	165,344	30%	-	-	159,190	536,788	159,190	-
12	141,192.00	178,912.00				320,104	7,847	100%	-	-	256,002	64,102	256,002	-
14	419,441.00					419,441	-	25 yrs	-	-	20,267	399,174	20,267	-
14	336,219.00					336,219	-	15 yrs	-	-	32,000	304,219	32,000	-
17	86,723.00					86,723	-	8%	-	-	6,938	79,785	6,938	-
43.2	6,713.00					6,713	-	50%	-	-	3,357	3,357	3,357	-
45	72.00					72	-	45%	-	-	32	40	32	-
46	1,967.00					1,967	-	30%	-	-	590	1,377	590	-
47	22,200,849.00	2,070,925.00			(4,500)	24,267,274	1,033,213	8%	-	-	1,858,725	22,408,549	1,888,886	(30,161)
50	126,635.00	94,549.00				221,184	47,275	55%	-	-	95,650	125,534	100,838	(5,188)
14.1	645,434.00	75,196.00				720,630	37,598	5%	-	-	47,061	673,569	47,061	-
98 - smart meters not in use (Inventory)	183,470.00	200,793.00			(183,470)	200,793	8,662	0%	-	-	-	200,793	-	-
98 - transformer stock (Inventory)	1,225,521.00	1,224,900.00			(1,225,521)	1,224,900	(311)	0%	-	-	-	1,224,900	-	-
														-
	50,134,707	4,659,921	-	$ - $ -	(1,417,031)	53,377,597	1,539,838	4	-	-	3,860,409	49,517,188	**3,907,262**	**(46,853)**
													Tax Rate	(12,416)
													Grossed-up	**(16,893)**

2019 Rolled with NO AIIP Applied

Class No. [200]	2 UCC BOY	3 Additions	3.1 DIEP	4 Adjustments	5 Proceeds*	6 UCC	7 Half Year Rule	9 Rate %	10 Recapture	11 Terminal Loss	12 CCA	13 UCC EOY	CCA As Filed	Difference
1	15,405,312					15,405,312	-	4%	-	-	616,212	14,789,100	616,212	-
1b	4,492,680	223,823				4,716,503	111,912	6%	-	-	276,275	4,440,227	289,649	(13,373)
2	2,064,641					2,064,641	-	6%	-	-	123,878	1,940,763	123,878	-
6	55,841					55,841	-	10%	-	-	5,584	50,256	5,584	-
8	1,476,529	405,907				1,882,436	202,954	20%	-	-	335,896	1,546,539	414,964	(79,068)
10	536,788	56,425				593,213	28,213	30%	-	-	169,500	423,713	186,428	(16,928)
12	64,102	253,649				317,751	7,847	100%	-	-	190,927	126,825	317,751	(126,825)
14	399,174					399,174	-	25 yrs	-	-	20,267	378,907	20,267	-
14	304,219					304,219	-	15 yrs	-	-	32,000	272,219	32,000	-
17	79,785					79,785	-	8%	-	-	6,383	73,402	6,383	-
43.2	3,357					3,357	-	50%	-	-	1,678	1,678	1,678	-
45	40					40	-	45%	-	-	18	22	18	-
46	1,377					1,377	-	30%	-	-	413	964	413	-
47	22,408,549	1,996,642				24,405,191	998,321	8%	-	-	1,872,550	22,532,641	2,029,868	(157,318)
50	125,534	75,790				201,324	37,895	55%	-	-	89,886	111,438	128,717	(38,831)
14.1	673,569	3,150				676,719	1,575	5%	-	-	45,762	630,957	45,920	(158)
98 - smart meters not in use (Inventory)	200,793	379,927			(200,793)	379,927	89,567	0%	-	-	-	379,927		-
98 - transformer stock (Inventory)	1,224,900	1,187,486			(1,224,900)	1,187,486	(18,707)	0%	-	-	-	1,187,486		-
														-
	49,517,188	4,582,799	-	$ - $ -	(1,425,693)	52,674,294	1,459,577	4	-	-	3,787,230	48,887,064	**4,219,730**	**(432,500)**
													Tax Rate	(114,613)
													Grossed-up	**(155,936)**

2020 Rolled with NO AIIP Applied

Class No. [200]	2 UCC BOY	3 Additions	3.1 DIEP	4 Adjustments	5 Proceeds*	6 UCC	7 Half Year Rule	9 Rate %	10 Recapture	11 Terminal Loss	12 CCA	13 UCC EOY	CCA As Filed	Difference
1	14,789,100					14,789,100	-	4%	-	-	591,564	14,197,536	591,564	-
1b	4,440,227	156,731				4,596,958	78,366	6%	-	-	271,116	4,325,843	279,661	(8,545)
2	1,940,763					1,940,763	-	6%	-	-	116,446	1,824,317	116,446	-
6	50,256					50,256	-	10%	-	-	5,026	45,231	5,026	-
8	1,546,539	323,963				1,870,502	161,982	20%	-	-	341,704	1,528,798	388,569	(46,865)
10	423,713					423,713	-	30%	-	-	127,114	296,599	122,036	5,078
12	126,825	97,425				224,250	7,847	100%	-	-	175,537	48,713	97,425	78,112
14	378,907					378,907	-	25 yrs	-	-	20,267	358,640	20,267	-
14	272,219					272,219	-	15 yrs	-	-	32,000	240,219	32,000	-
17	73,402					73,402	-	8%	-	-	5,872	67,530	5,872	-
43.2	1,678					1,678	-	50%	-	-	839	839	839	-
45	22					22	-	45%	-	-	10	12	10	-
46	964					964	-	30%	-	-	289	675	289	-
47	22,532,641	1,935,140				24,467,781	967,570	8%	-	-	1,880,017	22,587,765	2,018,542	(138,525)
50	111,438	52,039				163,477	26,020	55%	-	-	75,602	87,875	80,013	(4,411)
14.1	630,957					630,957	-	5%	-	-	42,713	588,244	42,705	8
98 - smart meters not in use (Inventory)	379,927	387,837			(379,927)	387,837	3,955	0%	-	-	-	387,837	-	-
98 - transformer stock (Inventory)	1,187,486	1,233,371			(1,187,486)	1,233,371	22,943	0%	-	-	-	1,233,371	-	-
	48,887,064	4,186,506	-	$ - $ -	(1,567,413)	51,506,157	1,268,683	4	-	-	3,686,115	47,820,043	**3,801,263**	**(115,148)**
													Tax Rate	**(30,514)**
													Grossed-up	**(41,516)**

2021 Rolled with NO AIIP Applied

Class No. [200]	2 UCC BOY	3 Additions	3.1 DIEP	4 Adjustments	5 Proceeds*	6 UCC	7 Half Year Rule	9 Rate %	10 Recapture	11 Terminal Loss	12 CCA	13 UCC EOY	CCA As Filed	Difference
1	14,197,536					14,197,536	-	4%	-	-	567,901	13,629,634	567,901	-
1b	4,325,843	408,325				4,734,168	204,163	6%	-	-	271,800	4,462,367	294,929	(23,128)
2	1,824,317					1,824,317	-	6%	-	-	109,459	1,714,858	109,459	-
6	45,231					45,231	-	10%	-	-	4,523	40,708	4,523	-
8	1,528,798	215,805	187,468			1,744,603	201,637	20%	-	-	496,061	1,248,542	474,428	21,633
10	296,599	16,511	16,511			313,110	16,511	30%	-	-	105,491	207,619	101,936	3,555
12	48,713	66,063				114,776	7,847	100%	-	-	81,744	33,032	66,063	15,681
14	358,640					358,640	-	25 yrs	-	-	20,267	338,373	20,267	-
14	240,219					240,219	-	15 yrs	-	-	32,000	208,219	32,000	-
17	67,530					67,530	-	8%	-	-	5,402	62,128	5,402	-
43.2	839					839	-	50%	-	-	420	420	420	-
45	12					12	-	45%	-	-	5	7	5	-
46	675					675	-	30%	-	-	202	472	202	-
47	22,587,765	2,310,647				24,898,412	1,155,324	8%	-	-	1,899,447	22,998,965	2,056,931	(157,484)
50	87,875	275,021	51,010			362,896	163,016	55%	-	-	160,944	201,952	257,514	(96,570)
14.1	588,244					588,244	-	5%	-	-	39,795	548,449	39,788	7
98 - smart meters not in use (Inventory)	387,837	366,392			(387,837)	366,392	(10,723)	0%	-	-	-	366,392	-	-
98 - transformer stock (Inventory)	1,233,371	1,348,500			(1,233,371)	1,348,500	57,565	0%	-	-	-	1,348,500	-	-
	47,820,043	5,007,264	254,989	$ - $ -	(1,621,208)	51,206,099	1,795,340	4	-	-	3,795,463	47,410,636	**4,031,769**	**(236,306)**
													Tax Rate	(62,621)
													Grossed-up	**(85,199)**

2022 Rolled with NO AIIP Applied

Class No. [200]	2 UCC BOY	3 Additions	3.1 DIEP	4 Adjustments	5 Proceeds*	6 UCC	7 Half Year Rule	9 Rate %	10 Recapture	11 Terminal Loss	12 CCA	13 UCC EOY	CCA As Filed	Difference
1	13,629,634					13,629,634	-	4%	-	-	545,185	13,084,449	545,185	-
1b	4,462,367	357,228				4,819,595	178,614	6%	-	-	278,459	4,541,136	297,134	(18,675)
2	1,714,858					1,714,858	-	6%	-	-	102,891	1,611,967	102,891	-
6	40,708					40,708	-	10%	-	-	4,071	36,637	4,071	-
8	1,248,542	70,439	70,439			1,318,981	70,439	20%	-	-	320,147	998,834	297,174	22,973
10	207,619	68,635	68,635			276,254	68,635	30%	-	-	130,921	145,333	128,432	2,489
12	33,032	14,427	14,427			47,459	7,847	100%	-	-	47,459	-	14,427	33,032
14	338,373					338,373	-	25 yrs	-	-	20,267	318,106	20,267	-
14	208,219					208,219	-	15 yrs	-	-	32,000	176,219	32,000	-
17	62,128					62,128	-	8%	-	-	4,970	57,158	4,970	-
43.2	420					420	-	50%	-	-	210	210	210	-
45	7					7	-	45%	-	-	3	4	3	-
46	472					472	-	30%	-	-	142	331	142	-
47	22,998,965	2,711,138				25,710,103	1,355,569	8%	-	-	1,948,363	23,761,740	2,125,287	(176,924)

50	$ 201,952	176,461	$ 176,461				$ 378,413	$ 176,461	55%	$ -	$ -	$ 287,535	$ 90,878	$ 207,785	$ 79,750
14.1	$ 548,449						$ 548,449	$ -	5%	$ -	$ -	$ 37,078	$ 511,371	$ 37,071	$ 7
98 - smart meters not in use (Inventory)	$ 366,392					$ (72,634)	$ 293,758	$ (36,317)	0%	$ -	$ -	$ -	$ 293,758	$ -	$ -
98 - transformer stock (Inventory)	$ 1,348,500					$ (39,761)	$ 1,308,739	$ (19,881)	0%	$ -	$ -	$ -	$ 1,308,739	$ -	$ -
Software not in use	$ -	211,458					$ 211,458	$ 105,729	0%	$ -	$ -	$ -	$ 211,458	$ -	$ -
	$ 47,410,636	$ 3,609,786	$ 329,962	$ -	$ -	$ (112,395)	$ 50,908,027	$ 1,907,096	$ 4	$ -	$ -	$ 3,759,700	$ 47,148,327	**$ 3,817,049**	**$ (57,349)**
														Tax Rate	$ (15,197)
														Grossed-up	**$ (20,677)**

2023 Rolled with NO AIIP Applied

1	$ 13,084,449						$ 13,084,449	$ -	4%	$ -	$ -	$ 523,378	$ 12,561,071	$ 523,378	$ -
1b	$ 4,541,136	916,436					$ 5,457,572	$ 458,218	6%	$ -	$ -	$ 299,961	$ 5,157,611	$ 351,068	$ (51,107)
2	$ 1,611,967						$ 1,611,967	$ -	6%	$ -	$ -	$ 96,718	$ 1,515,249	$ 96,718	$ -
6	$ 36,637						$ 36,637	$ -	10%	$ -	$ -	$ 3,664	$ 32,973	$ 3,664	$ -
8	$ 998,834	440,169	$ 440,169				$ 1,439,003	$ 440,169	20%	$ -	$ -	$ 639,936	$ 799,067	$ 621,557	$ 18,379
10	$ 145,333	92,935	$ 92,935				$ 238,268	$ 92,935	30%	$ -	$ -	$ 136,535	$ 101,733	$ 134,793	$ 1,742
12	$ -	221,093	$ 221,093				$ 221,093	$ 7,847	100%	$ -	$ -	$ 221,093	$ -	$ 221,093	$ -
14	$ 318,106						$ 318,106	$ -	25 yrs	$ -	$ -	$ 20,267	$ 297,839	$ 20,267	$ -
14	$ 176,219						$ 176,219	$ -	15 yrs	$ -	$ -	$ 32,000	$ 144,219	$ 32,000	$ -
17	$ 57,158						$ 57,158	$ -	8%	$ -	$ -	$ 4,573	$ 52,585	$ 4,573	$ -
43.2	$ 210						$ 210	$ -	50%	$ -	$ -	$ 105	$ 105	$ 105	$ -
45	$ 4						$ 4	$ -	45%	$ -	$ -	$ 2	$ 2	$ 2	$ -
46	$ 331						$ 331	$ -	30%	$ -	$ -	$ 99	$ 231	$ 99	$ -
47	$ 23,761,740	2,482,744					$ 26,244,484	$ 1,241,372	8%	$ -	$ -	$ 2,000,249	$ 24,244,235	$ 2,144,748	$ (144,499)
50	$ 90,878	290,629	$ 290,629				$ 381,508	$ 290,629	55%	$ -	$ -	$ 340,613	$ 40,895	$ 304,724	$ 35,889
14.1	$ 511,371						$ 511,371	$ -	5%	$ -	$ -	$ 34,549	$ 476,822	$ 34,542	$ 7
98 - smart meters not in use (Inventory)	$ 293,758						$ 293,758	$ -	0%	$ -	$ -	$ -	$ 293,758	$ -	$ -
98 - transformer stock (Inventory)	$ 1,308,739						$ 1,308,739	$ -	0%	$ -	$ -	$ -	$ 1,308,739	$ -	$ -
Software not in use	$ 211,458	330,356					$ 541,814	$ 165,178	0%	$ -	$ -	$ -	$ 541,814	$ -	$ -
	$ 47,148,327	$ 4,774,362	$ 1,044,826	$ -	$ -	$ -	$ 51,922,689	$ 2,696,348	$ 4	$ -	$ -	$ 4,353,740	$ 47,568,949	**$ 4,493,330**	**$ (139,589)**
														Tax Rate	$ (36,991)
														Grossed-up	**$ (50,328)**

	Grossed Up - PILS
2018	$ (16,893)
2019	$ (155,936)
2020	$ (41,516)
2021	$ (85,199)
2022	$ (20,677)
2023	$ (50,328)
Total	**$ (370,548)**

*****

The advice contained herein is based on the facts and assumptions stated herein. You have represented to us that you have provided us with all facts and assumptions that you know or have reason to know are pertinent to this matter. If these facts and assumptions are not entirely complete and accurate, it could have a material effect on our advice. Our advice takes into account the applicable provisions and published judicial and administrative interpretations of the relevant taxing statutes, the regulations thereunder and applicable tax treaties. Our advice also takes into account all specific proposals to amend these authorities or other relevant statutes or tax treaties publicly announced prior to the date of our advice, based on the assumption that these amendments will be enacted substantially as proposed. Our advice does not otherwise take into account or anticipate any changes in law or practice, by way of judicial, governmental or legislative action or interpretation. These authorities are subject to change, retroactively and/or prospectively, and any such changes could have an effect on our advice and may result in incremental taxes, interest or penalties. Unless you specifically request otherwise, we will not update our advice to take any such changes into account. If you carry on business or reside in Québec, Québec introduced legislation that prohibits a taxpayer who has carried out a transaction, or series of transactions, that is subject to a Revenu Québec final assessment based on the general anti-avoidance rule, from being able to obtain authorization from the Autorité des marchés publics (AMP) to bid for or obtain public contracts. The taxpayer will be listed in the Register of Enterprises Ineligible for Public Contracts for a period of five years from the time the name is entered on the list.

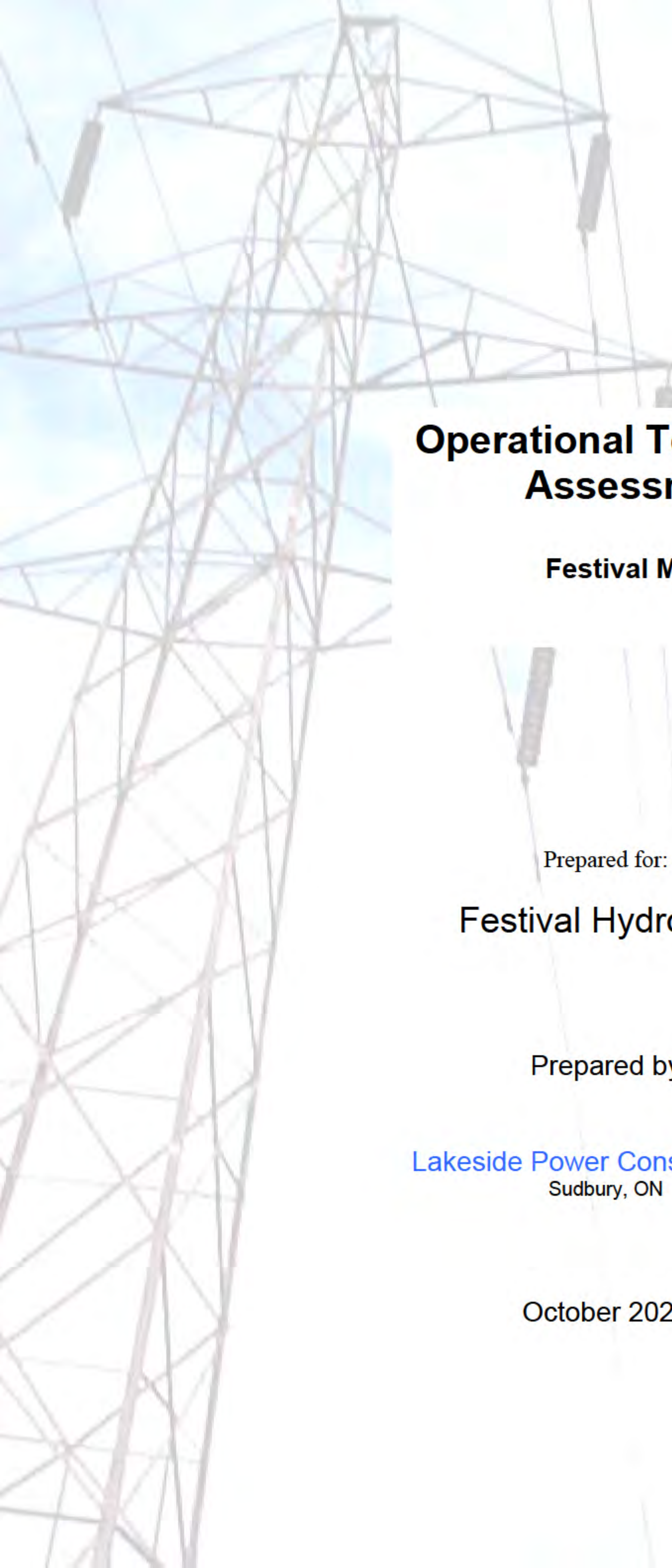
Advice relative to tax matters outside of Canada is based on tax advice provided by the KPMG International member firm in the particular country and on the relevant tax authorities in that country.

Our advice is limited to the conclusions specifically set forth herein. We provide no advice and express no opinion with respect to any other federal, provincial or foreign tax aspect of the matters described herein, nor with respect to any legal or other matters other than those specifically addressed herein. The Canada Revenue Agency and/or any other relevant provincial tax authority and/or foreign tax authority and/or other governmental tax authority (collectively a Tax or Revenue Authority) could take a different position with respect to the matters addressed herein (including the general anti-avoidance rule (GAAR)), in which case it may be necessary for you to defend this position on appeal from an assessment or litigate the dispute before the courts, including one or more appellate courts, in order for our advice to prevail. It should be noted that filings by both the taxpayer and by the Tax Authorities before the tax courts are a matter of public record and that this public access to the details of your tax dispute could potentially lead to unwanted scrutiny and publicity by tax commentators and by the business and general news media. If a settlement were reached with a Tax or Revenue Authority or if such appeal and litigation were not, or were not entirely, successful, the result would likely be different from the advice we provide herein. Unless expressly provided for, our services do not include representation in the event of a challenge by a Tax or Revenue Authority or litigation before any court.

Our advice is for the sole use of our client. The advice is based on the specific facts and circumstances and the scope of our engagement and is not intended to be relied upon by any other person. We disclaim any responsibility or liability for any reliance that any person other than our client may place on this advice.

Attachment 6

2-AMPCO-8 – Festival OT Report - Redacted



Operational Technology Assessment

Festival MTS 1

Prepared for:

Festival Hydro Inc.

Prepared by

Lakeside Power Consulting Inc.
Sudbury, ON

October 2022

Contents

1. Executive Summary

Lakeside Power Consulting Inc. has been retained by Festival Hydro Inc. (FHI) to perform an Operational Technology (OT) Assessment for the Festival MTS #1 station. This station is a 67 MVA, 230-28 kV Municipal Transformer Station (MTS) connected to the Hydro One B22D and B23D 230 kV transmission circuits. The station was placed into service in 2013.

This OT assessment focuses on the digital assets within the station, as it pertains to condition assessment and remaining useful life. The results of this assessment are intended to be used to plan for capital investments in asset life extension or replacement, as well as operational expenses for ongoing maintenance and operation.

The normal typical life of an MTS is more than 40 years, but certain components have shorter life spans. This station is approaching ten years in service. The assessment has determined that certain digital assets are candidates for replacement either by experiences of premature failure or reaching the end of life.

The assessment has also highlighted concerns with routine inspections and maintenance activities, and recommendations are provided to address this issue.

2. Introduction

The Festival MTS #1 station is a 230-28 kV, 67 MVA MTS located in the southwest side of the City of Stratford. This station was placed into service in 2013 by Festival Hydro to service new load growth that was developing in the area. This station is referred to as a DESN station, a Dual Element Spot Network station that is designed with a great deal of redundancy and planned transformer overload capacity to be able to survive a failure of a single major component (transmission circuit, transformer, bus) and continue to supply load.

These stations are designed and constructed to meet the technical standards of the Ontario IESO and the OEB Transmission System Code (TSC), which are both based on NERC (North American Electric Reliability Corp) standards. The operation and maintenance of this facility also must meet the applicable regulatory requirements as a condition of remaining connected to the grid.

Not withstanding the imposed regulatory requirements, Festival Hydro has made a significant long-term investment in this station and has a vested interest in maintaining this asset for the safety and security of local supply in Stratford. Transformer stations are generally considered to be forty (40) year assets, although specific components such as protective relays and power cables have typically shorter life expectancies.

In 2010 Kinectrics Inc. was engaged by the OEB to provide a report titled “Asset Depreciation Study” under case EB-2010-0178. At that time utilities were transitioning accounting systems from GAAP to IFRS, and IFRS does not allow for externally mandated depreciation rates. The Kinectrics study has since been used as a guideline by Ontario utilities to depreciate assets on their actual condition, with consideration to asset-specific minimum, maximum, and typical useful life spans. This report is relevant to this OT assessment, as any significant deviation from the report’s guidelines would possibly require substantiation from FHI.

We will note that the bulk of the Kinectrics report covers assets external to substations, including different types of distribution poles, transformers, and insulated power cables. The report refers to general classes of station assets, but there is in our opinion room for interpretation on the life span of many digital assets. One of the major factors impacting the useful life of digital assets is technical obsolescence, whereby products may not be supported beyond 5-10 years from manufacture. This can be caused by several factors, such as lack of spare parts or lack of product knowledge. This can also be caused by the rapid development of new technologies. Early retirement of digital assets may be warranted if new products offer more functionality, lower operating cost, greater support from vendors, and availability of spare parts.

Discussions about the typical useful life of assets in stations are useful in the determination of depreciation and capital replacement. Operating and maintenance (O&M) factors may be more significant in this discussion, as the station is in its early overall life span. After about nine (9) years of station ownership, capital replacement of equipment should be somewhat limited. Major components have typical life spans closer to twenty (20) years. However, known issues with specific equipment, whether by defect or premature failure rates, may lead to the prioritization of spending both on the capital and O&M sides.

3. Asset Inventory

3.1 Protection Systems

DESN station protection systems are critical to the safe and reliable operation of the transformer station and for the downstream protection of the distribution system. Most protection systems are designed with redundant backup protections, supplied by independent DC battery systems.

According to the Kinectrics study, they sampled four (4) LDC's and derived the following typical life spans for digital and numerical relays:

Asset Component	Useful Life		
	Min UL	TUL	Max UL
Digital and numeric relays	15	20	20

We note that the sample size of the number of LDC's that responded to the Kinectrics study is small. We believe that many LDC's replace these assets sooner than the TUL-spans noted above. Technical obsolescence is a major factor in this category.

The station has 23 protection relays/devices in service. In 2020 FHI initiated a program to replace the General Electric UR-series relays in the station. The T1-side relays were completed in 2021, with the intention to carry on with the replacement of the T2-side relays. These relays are less than ten (10) years old, and their replacement seems premature by the Kinectrics model. FHI staff were aware of premature failures of power supplies of these relays at another Ontario LDC and the fact that the vendor would not support the relay firmware past 2022.

3.2 SCADA

The MTS station is fully automated with SCADA RTU's, controllers, IED's, and protective relays. In addition, the station supplies a subset of SCADA telemetry to Hydro One Networks Inc (HONI) and the IESO.

The station uses primarily SEL SCADA equipment, including a SEL 3354 hardened computer, and several SEL 2440 DPAC I/O modules. The station local area network (LAN) is a hardened redundant fibre optic TCP/IP system, using primarily Siemens Ruggedcom networking hardware.

The station SCADA interface (HMI) is provided by a workstation connected to the utility SCADA master system, manufactured by Survalent. One of the Survalent master computers is located at the station.

In our experience, most stations are configured with a central SCADA RTU/data concentrator that collects all the various SCADA telemetry from all of the station devices and offers the data to the SCADA masters (FHI, HONI, IESO). In this station, the Survalent SCADA system has been configured to poll individual devices within the station. We raise this only to highlight that the station SEL 3354 computer platform is NOT playing the role of a central RTU. We had the impression from staff that they believed that it was acting as the station RTU. The SEL 3354 computing platform is obsolete and has been replaced by the SEL 3355 computing platform.

Our experience with SEL as a manufacturer has been very good. All their products have a ten (10) year warranty, but they claim informally that they have never denied a warranty claim based on age. Technical support at SEL is also excellent.

The station power transformers were supplied with QEI 6CPP6 RTU's that act as data concentrators for all the SCADA telemetry on the transformers. These RTU's are not widely used in Canada, and during our study we had challenges with obtaining technical support from QEI. The T1 transformer RTU is presently experiencing a problem with the analog telemetry from the Qualitrol ITM 509 controller (only analog points are polled from the ITM 509).

The IESO owns a small Eaton Cybectec SMP 4/DP RTU, which polls the SEL 3354 for key transmission-related SCADA telemetry. This RTU is located in the relay panels.

Hydro One Networks Inc (HONI) gets their SCADA telemetry via ICCP protocol from the Festival SCADA system.

According to the Kinectrics study, SCADA RTU's have typical life spans as follows:

Asset Component	Useful Life		
	Min UL	TUL	Max UL
Remote Terminal Units	15	20	30

Our experience is that RTU's are typically replaced between 10-15 years, but technical obsolescence is also a major factor for early replacement.

3.3 Metering

The station utilizes 230 kV primary metering instrument transformers and redundant meters for each incoming 230 kV circuit. These meters are read remotely each day by the IESO and Festival's meter service provider (MSP).

There is a spare instrument transformer located at the station. The Market Rules require Festival to have a registered plan stating how they would handle they failure of any metering component.

The metering equipment is sealed and was not available for inspection and inventory for this study. Festival should consult with the MSP for planned replacement of meters.

Kinectrics states that the typical useful life for wholesale meters is 10-15 years. The Measurement Canada seal period is 10 years, and the metering IT's should have a long useful life of about 40 years.

3.4 Controllers

Closely related to protection relays, the station uses Beckwith voltage regulation controllers to operate the load tap changers (LTC's) on the two power transformers to regulate the bus voltages at the station. There are several Beckwith devices for each transformer that operate together as a system. Beckwith is a well-known manufacturer with a proven track record and good technical support.

The Kinectrics study does not reference this category of equipment, but we would equate it to the digital relay classification. As such, the following typical useful life may apply:

Asset Component	Useful Life		
	Min UL	TUL	Max UL
Digital and numeric relays	15	20	20

3.5 Computers

There are six personal computers in use at the station, as follows.

Two laptop computers were provided by Siemens with the 8DA10 medium voltage switchgear. These laptops are used with the proprietary software supplied by Siemens to view the cameras inside the switchgear to confirm the state of the three-position switches. These computers are roughly 10 years old and are running Windows 7.

The power transformers are equipped with touch screen PC's to act as the SCADA HMI for the transformer. These computers are roughly ten years old and run Windows XP. These computers are rarely used.

Two PC's are thin client Leveno ThinkCentre computers that are managed by the Fetsival IT department. One is connected to the OT (SCADA) network, and the other to the Corp network. Both machines run Windows 10 Pro.

The Kinectrics study Table F-2 lists computer equipment life at 3-5 years for hardware, and 2-5 years for software.

3.6 Networking

The inventory of network assets was limited to the substation OT network. There are other IT assets located at the station that are out of scope of this study.

The station has a fibre optic TCP network that is used for both SCADA and protection. The network has redundant A and B equipment, with some equipment connected to both networks, but most only connected to one network. The network is mostly redundant from a hardware perspective, but IP-enabled devices typically have one IP address.

The station switches are manufactured by Siemens Ruggedcom and are designed for use in harsh environments (temperature, humidity, noise). There are four switches in the medium voltage GIS gear, and four switches in the relay and control panels.

Again, the Kinectrics study Table F-2 lists computer equipment life at 3-5 years for hardware, and 2-5 years for software. There is no specific mention of networking equipment in the Kinectrics study, and we expect that the typical useful life of these devices is more in the range of 10-15 years.

3.7 Critical Power Supplies

There are three critical AC and DC power systems in use at the station.

There are two 125 Vdc battery systems that supply critical power to protection and control systems. The Transmission System Code only requires one DC battery systems for tapped load stations, but many stations have been constructed with two systems for redundancy and to facilitate maintenance. FHI plans to replace the A battery system in 2022, and the B battery system in 2023 or 2024 depending on diagnostic testing.

There is a 13.5 kW AC inverter that supplies AC power to important systems, mostly station lighting, telecom equipment, and receptacles. The source of the normal AC power is provided by an automatic transfer switch that switches between station service power from the J bus and the Z bus. The nameplate states it can supply 13.5 kW for up to 120 minutes.

The inverter is operating in bypass mode, meaning that the battery backup system is essentially out of service.

Kinectrics states the typical useful life as follows:

Asset Component	Useful Life		
	Min UL	TUL	Max UL
Batteries	10	15	15
Charger	20	20	30

3.8 Fire – Security

The station fire alarm panel is a Simplex Model 4008 panel, which is monitored by an alarm company. The fire system is connected to multiple smoke and heat sensors, which are typically tested on an annual basis.

There is also a sump control system in the basement of the station, equipped with two redundant pumps to expel accumulated water in the basement & weeping tile system. The alarms for these pumps are connected to the station SCADA.

The Kinectrics report does not provide any information on typical life spans of these systems.

4. Condition Assessment

4.1 Protection Systems

The protection and control systems are critical to the safe operation of the transformer station. Festival has replaced the T1-side GE UR relays and is planning on replacing the T2-side relays as well. We understand that the justification of this project is that there were premature failures that was impacting the confidence of these systems.

There are two SEL 487E transformer differential relays in use as backup protection for the main power transformers. These units should have at least 5-10 years of remaining useful life.

Our main concern on P&C systems is more related to fixing issues that have been identified during maintenance and other on-site inspections and projects, some of which have been present since the station went into service. These are very complex systems, with a limited number of qualified contractors to provide excellent support. An evaluation on selection of a contractor must be heavily weighted to consider the qualifications and experience of the staff working on this specific type of equipment. Further, we suggest that once a contractor is selected, keep using that contractor for consistency.

As for the typical useful life of these assets, except for known quality issues and technical obsolescence, these assets should have 15-20 years of useful life.

4.2 SCADA

Even though Kinectrics reports typical useful lives of SCADA assets to be in the 20-year range, our experience is that technical obsolescence drives replacement in the 10–15-year range. Given that the bulk of the SCADA devices are manufactured by SEL, we feel that these assets should last 15 years.

The SEL 3354 hardened computer platform is no longer in manufacture, but it has been replaced with a similar unit SEL 3355. Functionally it is almost identical but has newer and faster processors and current I/O adapters. The 3354 plays a relatively minor role in the overall SCADA system, but since it is essentially a hardened personal computer, it could be a target for replacement as it is already 10 years old.

The QEI 6CPP6 RTU's installed in the power transformers could also be candidates for replacement since they are no longer manufactured and are obsolete. Recent technical support has been challenging as well. QEI does offer upgrade paths whereby I/O modules can be re-used, simplifying the wiring done during the upgrade. This would still leave Festival with a newer version of the QEI RTU, with no Canadian support channel. A SEL Axion RTAC system would also be a candidate for this application.

The transformer SCADA system includes Qualitrol ITM 509 transformer monitor relays and GE Hydran dissolved gas meters. FHI has experienced the failure of one ITM 509 relay recently. These relays are supported by their respective vendors, and should have at least five more years of useful life.

In reviewing the plans for SCADA upgrades and replacements at the station, Festival should consider the overall architecture of the system, and evaluate the need for a station RTU/data concentrator.

4.3 Metering

Wholesale metering requirements with respect to replacements and reverifications are dictated by Measurement Canada. Along with the MSP, Festival must coordinate meter replacements in accordance with industry regulations.

4.4 Controllers

The station voltage regulation systems are critical to the ongoing operation of the transformer station. To our knowledge Festival does not maintain any spare Beckwith relays. Should one voltage regulation system fail, Festival would have to remove one transformer from service until repairs are made.

These components should have a life of at least 15 years, but we suggest that replacements be purchased and kept on hand as spares.

4.5 Computers

The two Leveno Think Centre RTU's are managed by Festival's IT group and appear to be modern units with up-to-date operating systems.

The two Dell laptops provided by Siemens with the 8DA10 medium voltage switchgear are at least ten (10) years old and are running Windows 7. These units are obsolete and are candidates for replacement. These laptops are not necessarily critical, but if they are called to verify a three-position switch and don't work, it could interrupt planned work. If this is a concern FHI should replace these laptops.

The touch screen HMIs on the power transformers are also obsolete and are not used by Festival staff. When evaluating the options for replacement of the transformer RTU's, the ongoing need for an HMI can be considered. It is likely that this system could simply be abandoned.

4.6 Networking

The main substation networking equipment is based on Siemens Ruggedcom RSG2100 switches. In our experience these are quite reliable, but since they are already ten years old, they are candidates for replacement. At a minimum, spare units should be purchased in case of failures.

Festival should also consider enabling SNMP management features of the networking equipment and monitor the network to find problems before they impact operations.

We also suggest that Festival purchase some spare multimode fibre cables and have them in stock.

4.7 Critical Power Supplies

Next to the power transformers, the critical power supplies are likely the most important assets in the station.

The DC chargers and batteries are absolutely critical to the safe operation of the station. The chargers have a relatively long-life span, but batteries require more frequent replacement. The Kinectrics TUL of 15 years seems to be high in our opinion. Our recommendation is to replace the batteries entirely after ten (10) years, or earlier if there is evidence of degradation.

The AC inverter is not functioning and hasn't been functioning for some time. This device provides backup AC power to station lighting, telecommunications equipment, and receptacles.

4.8 Fire – Security

We understand that the fire system is maintained by a local contractor with the required expertise. The fire system is maintained regularly in accordance with the manufacturer's recommendations and to meet any local fire department requirements.

The sump pump system should also be checked during regular physical inspections of the station.

Kinectrics provides no information on typical useful life of these assets.

5. Recommendations

We offer the following recommendations for consideration by Festival Hydro.

5.1 Critical Power Supplies

Festival should investigate and repair/replace the AC inverter system if there is concern for continuous power for station lighting and telecommunication facilities. FHI staff have indicated that they plan to review the loads connected to this UPS and re-evaluate the need for this device.

Festival should continue with the planned replacement the A and B battery systems.

5.2 SCADA System

Festival should replace or upgrade the SCADA RTU's in the power transformers.

Festival should review the station architecture and polling strategy when considering SCADA upgrades.

Festival should consider the replacement of the 3354 computing platform, as it is obsolete. This may be less critical depending on the role of this device. FHI may consider a traditional RTU platform instead of a hardened-PC.

Festival should review the alarms generated by IED's and relays on the entire station.

5.3 Relay Replacements

Festival should continue with the replacement of the T2-side GE UR relays, based on the rationale to replace the T1 relays. We do recommend that when doing the T2 side, Festival consider a turn-key approach whereby a contractor does the up-front engineering, procurement, installation, and commissioning. The T1 phase of the project was problematic in that Festival procured the relays without any advance engineering, and this resulted in additional costs and delays in the installation/commissioning phase.

5.4 Spare Equipment

Festival should consider the purchase of spare components, especially for specialized and/or long delivery items. This includes:

- Beckwith voltage regulation relays
- SEL 487E transformer differential relay
- ABB NSD570 Relay
- SNC Optical Isolation – spare unit cards
- Siemens Ruggedcom Ethernet Switches
- Multimode fibre optic cables
- Spare fuses for control systems

5.5 Station Network

Festival should consider the implementation of network monitoring at the station. This would typically be done by IT resources, using SNMP protocol to network devices to monitor network health.

5.6 Station Operations and Maintenance

The need for routine inspections, repair of known defects, and scheduling of routine maintenance are substantial and critical for these facilities, and we believe this is an area that FHI needs to further formalize their process. There are industry-standard practises for routine inspections, and FHI may be at risk if its practises are substantially different. Physical inspections are normally completed on a weekly basis, and the accompanying SCADA alarms are verified each time.

During this OT Assessment project, we discovered that the transformer SCADA telemetry for T1 had been down for about two years. FHI was aware of this issue, but it was not resolved due to staff turnover and other higher priority issues.

We are aware that FHI has recently hired staff with HV stations experience, with the intent of resolving these ongoing concerns.

Regarding planned maintenance activities, FHI historically has contracted planned maintenance to qualified high voltage station contractors. We understand that several firms have been doing maintenance on this station over the past ten years. Consistency in staff and contractors is very important. We strongly feel that Festival should select a single long-term contractor, if possible, perhaps under a master services agreement.

On a recent project, Festival’s T2 protection system mis-operated and adversely impacted the B23D transmission system. We found incorrect settings loaded into the relay, which was later found to be the source of the protection mis-operation. There was no way to determine how long the incorrect settings were applied to the relay, or who loaded the incorrect settings.

In summary we feel that Festival needs to make improvements on routine maintenance and operations of the station. As assets age, failures will be more frequent, and ongoing maintenance and inspections may avoid damage and undue outages.

6. Conclusion

The Festival MTS is approaching 10 years of operation. The station has a typical life span of 40 or more years, but minor assets have a lower typical life. Festival is encouraged to look at the existing deficiencies and make immediate repairs or capital replacements. In the next five (5) years, Festival can consider the replacement of digital assets such as protective relays, SCADA equipment, and supporting equipment such as AC/DC power supplies. In the next 5-15 years, Festival may need to focus on replacement of assets such as power cables and making improvements to the switchgear and control building.

Asset Inventory

Asset Inventory

Festival Hydro
Wright MTS #1
OT Assessment
31-Aug-22

Stephen Costello
Lakeside Power Consulting Inc.

Asset Inventory

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Protection	Manufacturer	Model	IP	Part No	Serial No	Software	
1	T1-A	T87A	GE	UR-T60	[redacted]	[redacted]	[redacted]	[redacted]	
2	T1-B	T87B	SEL	487E	[redacted]	[redacted]	[redacted]	[redacted]	
3	T1J-old	50-51-BF	GE	UR-C60	[redacted]				
4	M1	50-51-79-BF	GE	UR-D60	[redacted]	[redacted]	[redacted]	[redacted]	
5	M2	50-51-79-BF	GE	UR-D60	[redacted]	[redacted]	[redacted]	[redacted]	
6	M3	50-51-79-BF	GE	UR-D60	[redacted]	[redacted]	[redacted]	[redacted]	
7	M4	50-51-79-BF	GE	UR-D60	[redacted]	[redacted]	[redacted]	[redacted]	
8	M5	50-51-79-BF	GE	UR-D60	[redacted]	[redacted]	[redacted]	[redacted]	
9	M6	50-51-79-BF	GE	UR-D65	[redacted]	[redacted]	[redacted]	[redacted]	
10	SS1	50-51-BF	GE	UR-C60	[redacted]	[redacted]	[redacted]	[redacted]	
11	SS2	50-51-BF	GE	UR-C60	[redacted]	[redacted]	[redacted]	[redacted]	
12	JZ1	50-BF	GE	UR-C60	[redacted]	[redacted]	[redacted]	[redacted]	
13	ZJ2	50-BF	GE	UR-C60	[redacted]	[redacted]	[redacted]	[redacted]	
14	T2-A	87A	GE	UR-T60	[redacted]	[redacted]	[redacted]	[redacted]	
15	T2-B	87B	SEL	487E	[redacted]	[redacted]	[redacted]	[redacted]	
16	T2Z	50-51-BF	GE	UR-C60	[redacted]	[redacted]	[redacted]	[redacted]	
17	Bus-J	B87A	GE	UR-B30	[redacted]	[redacted]	[redacted]	[redacted]	
18	Bus-Z	B87A	GE	UR-B30	[redacted]	[redacted]	[redacted]	[redacted]	
19	T1J	50-51-BF	GE	UR-C60	[redacted]	[redacted]	[redacted]	[redacted]	New unit replaced by GE 2022
20	ISO 1	TT	SNC	Lyte Linx C					
21	ISO 2	TT	SNC	Lyte Linx C					
22	L1 TeleProt	TT	ABB	NSD570					
23	L2TeleProt	TT	ABB	NSD570					

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Location	Manufacturer	Model	IP	Part No	Serial No	Software
2	RTU	P102	SEL	3354	[redacted]			
3	IO Module 1	P102	SEL	DPAC 2440				
4	IO Module 2	P102	SEL	DPAC 2440				
5	IO Module 3	P102	SEL	DPAC 2440				
6	Ttrip	P102	SEL	DPAC 2440			[redacted]	
7	Clock	P102	SEL	2407				
8	IO Module 4	P202	SEL	DPAC 2440		[redacted]	[redacted]	
9	IO Module 5	P202	SEL	DPAC 2440				
10	IO Module 6	P202	SEL	DPAC 2440				
11	T1 RTU	T1	QEI	6CPP6	[redacted]			
12	T2 RTU	T2	QEI	6CPP6	[redacted]			
13	T1 Hydran	T1	GE	M2				
14	T2 Hydran	T2	GE	M2				
16	T1 ITM	T1	Qualitrol	ITM 509				[redacted]
17	T2 ITM	T2	Qualitrol	ITM 509				[redacted]
18	IESO	RP	CybecTec	SMP 4/DP		Likely owned by IESO		

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Function	Manufacturer	Model	SN	IP
1	T1-Revenue	L1-Main	Unknown			[redacted]
2	T1-Revenue	L1-Alt	Unknown			
3	T2-Revenue	L2-Main	Unknown			
4	T2-Revenue	L2-Alt	Unknown			

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Location	Manufacturer	Model	SN	Software
1	ES-Main-1	P102	Ruggedcom	RSG2100		
2	ES-Alt-1	P102	Ruggedcom	RSG2100		
3	ES-Main-2	P202	Ruggedcom	RSG2100		
4	ES-Alt-2	P202	Ruggedcom	RSG2100		
5	Office		EdgeSwitch	ES8		

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Protection	Manufacturer	Model	SN	Software
1	GIS A		Dell		[redacted]	Windows 7
2	GIS B		Dell		[redacted]	Windows 7
3	FH-OT-WS-02	Office	Leveno	[redacted]	[redacted]	Win10Pro
4	CORP	Office	Leveno	[redacted]	[redacted]	Win10Pro
5	T1 HMI		AdvanTech	[redacted]		WinXP
6	T2 HMI		AdvanTech	[redacted]		WinXP

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Protection	Manufacturer	Model	SN	Software
1	T1-90V	Regulation	Beckwith	M-2001C		[redacted]
2		Balancing	Beckwith	M-0115A		[redacted]
3	T2-90V	Regulation	Beckwith	M-2001C		
4		Balancing	Beckwith	M-0115A		[redacted]
5	T1-50/90V	AC Current	Beckwith	M-0127A		
6	T2-50/90V	AC Current	Beckwith	M-0127A		
7	J-90V	LTC BU Contr	Beckwith	M-5329		
8	Q-90V	LTC BU Contr	Beckwith	M-5329		
9	T1-CurrentLp	Current Loop	Beckwith	M-2025B		
10	T2-CurrentLp	Current Loop	Beckwith	M-2025B		

Festival Hydro
Wright MTS #1
OT Assessment

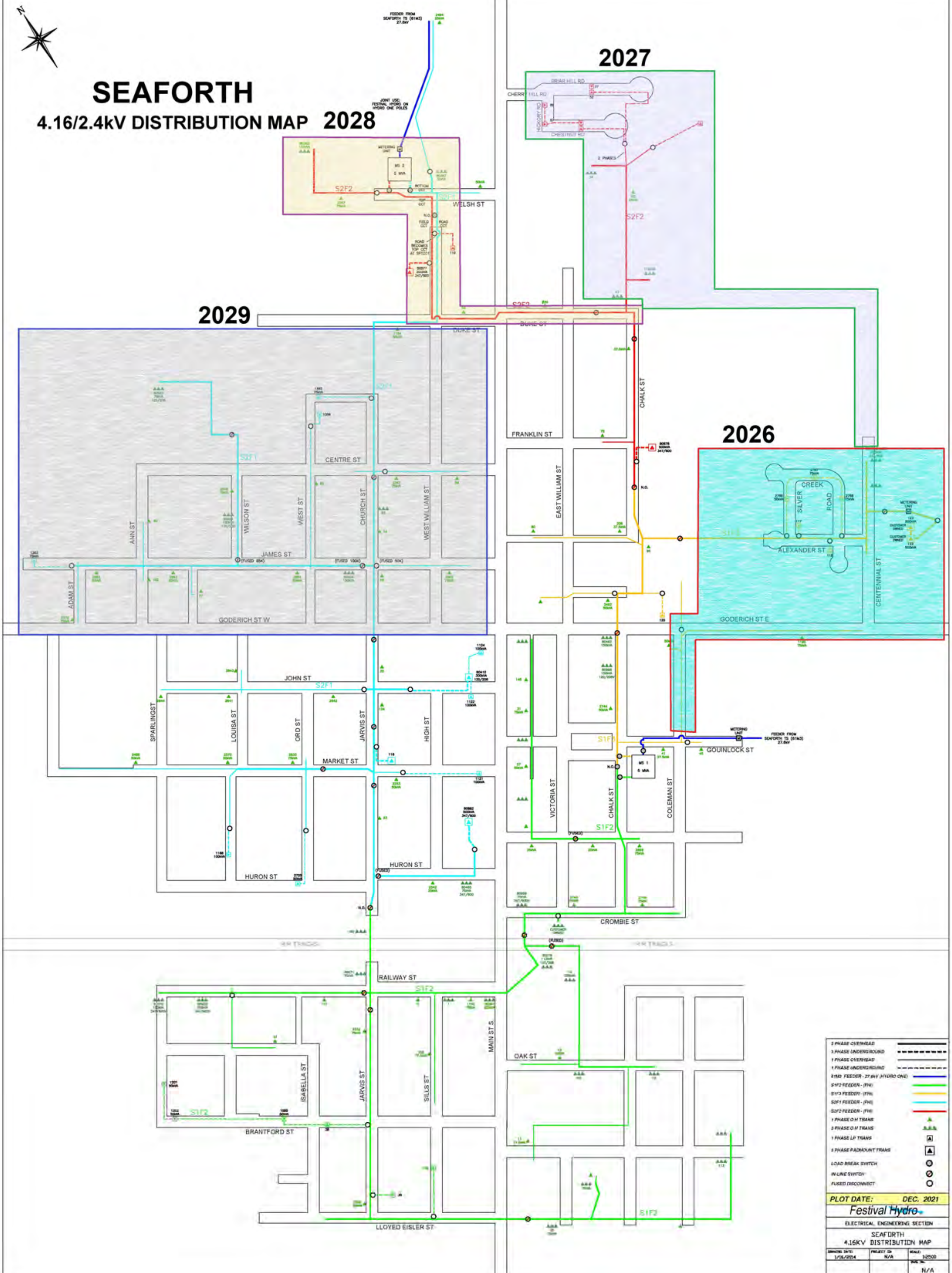
No.	ID	Protection	Manufacturer	Model	SN	Software				
1	UPS	Critical AC	Thomas & Betts	AIII1C12BJL	[redacted]		In 120/208Vac		Out 120/208Vac	13.5 Kw
2		Battery		GPL-121000			120 min	4 strings x 10		
3		Control		ACS-1761						
4										
5	DC A	DC A	LaMarche	A12B						
6	DC B	DC B	LaMarche	A12B						

Festival Hydro
Wright MTS #1
OT Assessment

No.	ID	Function	Manufacturer	Model	SN	Software
1	Fire		Simplex	[redacted]		

Attachment 7

2-AMPCO-22 – Seaforth 2026-2029 Projects



SEAFORTH
4.16/2.4kV DISTRIBUTION MAP
2028
2027
2029
2026
BRIAR HILL RD
CHERRY HILL RD
CHESTNUT RD
HICKORY RD
S2F2
S2F1
S1F1
S1F2
WELSH ST
DUKE ST
CHALK ST
FRANKLIN ST
EAST WILLIAM ST
CENTRE ST
ANN ST
WILSON ST
WEST ST
CHURCH ST
WEST WILLIAM ST
JAMES ST
ADAM ST
GODERICH ST W
GODERICH ST E
CREEK
SILVER
ROAD
ALEXANDER ST
CENTENNIAL ST
JOHN ST
SPARLING ST
LOUISA ST
ORD ST
JARVIS ST
HIGH ST
MARKET ST
VICTORIA ST
COLEMAN ST
GOUINLOCK ST
HURON ST
CROMBIE ST
RAILWAY ST
MAIN ST S.
OAK ST
ISABELLA ST
SILLS ST
BRANTFORD ST
LLOYED EISLER ST
PLOT DATE: DEC. 2021
Festival Hydro
ELECTRICAL ENGINEERING SECTION
SEAFORTH
4.16KV DISTRIBUTION MAP

Attachment 8

1-SEC-2 – Application Approval Documents

FHI Audit Committee Minutes

Board of Directors
Jan 30, 2024 at 4:00 PM EST
@ Virtual

Attendance

Present:
[redacted]

[redacted] [redacted]
[redacted]

[redacted] [redacted]
[redacted]

[redacted] [redacted]
[redacted]

[redacted]

[redacted]

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12. 2025 Capital and OM&A Budget

The Audit Committee reviewed the 2025 Capital and OM&A Budget, and supplemental commentary provided.

The Committee was reminded that the purpose of providing this budget earlier than typically seen in the fiscal year is a result of the work being done to prepare the COS application, to continue open communication, and subsequently for Board members to have a thorough understanding of the process being undertaken to prepare, document and present the COS application in spring 2024. Continuous collaboration with the Board benefits and supports employees and FHI overall in navigating the application process and resulting outcomes.
The Committee explored the results of past Asset Condition Assessments, impacts of the economic conditions, inflation, and availability and cost of labour and materials in relation to their impact on the budget.
It was agreed that there remains a need to consider and explore the risks associated with these projects on employee capacity, wellness and retention. The Committee was reassured by the Executive Leadership Team's ongoing commitment to monitor employee wellness. The Team also clarified the intention to source approximately 6 months worth of contracted labour and proactively plan and design work needed. The 2023 creation of an integral Project Manager role to assist with project oversight and timelines has also already proven to be of tremendous benefit. It was reported to the Committee that current projects (such as the CIS replacement) are driving overall employee positivity and effective change management is underway, resulting in eagerness for project participation and the resulting efficiencies for many roles.
In regards to the Capital Budget:

- **Page 79** - The amount on a per customer basis should read $326.14.
- **Page 88 - Seaforth Railway Crossing** - It was explained that since replacing the 4 poles at the same crossing, industry standards have changed; therefore, replacing them like-for-like will no longer adequately meet today's standards. As a result, the project work must be done underground.
- **Page 95 - Transformers** - It was reported that delays in obtaining the supplies needed in time for project execution in 2025 is not currently of concern. Executive Leadership reports having consistent monthly meetings with the vendor to review progress, risks and needs, in addition to supplying the vendor with a forecast of supply needed for the coming year typically in Q3-Q4. Lastly, FHI has attempted to standardize parts being used and ordered with other utilities to mitigate delay and cost risk.
- **Page 97 - Tools -** The 2024 and 2025 budget for tools has seen a rise from $30,000 to upwards of $45,000. This increase is explained by the increasing cost overall of tools, and to ensure the right tools and quantity are available for our crews to execute the large projects planned within those fiscal years.

In regards to the OM&A Budget:
It was clarified that the Cost of Service costs that are amortized over five years are incremental increases to our normal operating costs.
The Audit Committee then reviewed the Preliminary 5 Year Budget, and supplemental commentary provided.
It was clarified that for the ERP budget line, $875,000 includes labour, whereas $750,000 would represent solely the software costs.
It was agreed that it would be beneficial to recalculate and review with the Board our debt capacity in late 2024.

12 b. 2025 Capital Budget.pdf

2025 Budget Commentary_v2.pdf

5 Year Plan Commentary FHI v3.pdf

2025 Yr Budget 01252024 HC.pdf

Motion:

The Audit Committee recommends that the Board approve the Preliminary 2025 and 5 Year Capital, Operating and Administrative Budget and Cash Flow Statements as presented.

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FHI Board of Directors Meeting Minutes

Board of Directors
Feb 1, 2024 at 4:00 PM EST
@ Best Western Plus The Arden Park Hotel - 552 Ontario St., Stratford

Attendance

Present:
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4.7. 2025 Capital and OM&A Budget

It was expressly noted for the Board that the 2025 budgets are preliminary and that a final draft will be presented in fall 2024 after FHI's Cost of Service settlement with the OEB. The Board was reminded that the purpose of providing this budget earlier than typically seen in the fiscal year is a result of the work being done to prepare the COS application, to continue open communication, and subsequently for Board members to have a thorough understanding of the process being undertaken to prepare, document and present the COS application in spring 2024.

It was clarified that 2025 is considered as the "test year" within the COS application, meaning that year is reviewed in significant detail by the OEB and intervenors as part of the approval process.

The 2025 budget Includes two major projects within the Capital Budget, including a meter replacement project of approximately 20,000 meters, and a new ERP implementation. Both of these major projects are in addition to the required replacement of the roof on the administration building.

The Audit Committee Chair further noted that within the OM&A budget, the revenue included is a preliminary estimate of expected revenues, and that numbers may change dependent on the COS application approval process.

Overall, the 5 year budget anticipates approximately $12.5 million debt, expected to be incurred between 2025-2029. Due to this, the Committee reported requesting a recalculation of FHI’s debt capacity for Board review before the end of 2024, to ensure FHI maintains the financial flexibility needed to respond to any potential large unexpected expenditures should they occur.

The Committee reports remaining diligent to ensure the Executive Leadership Team continuously considers, monitors and explores the risks associated with these projects on employee capacity, wellness and retention. The Committee heard of ongoing efforts in this area, including the intention to source contracted labour and proactively plan and design work needed. It was reported by the Committee that current projects (such as the CIS replacement) are driving overall employee positivity and effective change management is underway, resulting in eagerness for project participation and the resulting efficiencies for many roles.

Motion:

It was moved that the Board approve the Preliminary 2025 and 5 Year Capital, Operating and Administrative Budget and Cash Flow Statements as presented.

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FESTIVAL HYDRO INC.

Balance Sheet 2025 Budget

	YTD as at Dec 31, 2022	YTD Prelim. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2024	YTD Bdgt. as at Dec 31, 2025	2024 Bdgt to 2025 Bdg YTD Var$	2024 Bdgt to 2025 Bdg YTD Var%	YTD Bdgt. as at Dec 31, 2026	YTD Bdgt. as at Dec 31, 2027	YTD Bdgt. as at Dec 31, 2028	YTD Bdgt. as at Dec 31, 2029
ASSETS											
Current Assets											
Cash	—	—	1,832,102	—	1,783,839	1,783,839	—	—	—	—	—
Accounts Receivable	8,460,478	8,751,678	7,000,000	7,500,000	8,500,000	1,000,000	13%	8,500,000	8,500,000	8,500,000	8,500,000
Inventory	177,526	212,005	200,000	200,000	200,000	—	—	200,000	200,000	200,000	200,000
Prepaid Expenses	230,441	212,592	450,000	450,000	450,000	—	—	450,000	450,000	450,000	450,000
Due from FHSI	122,147	-31,355	126,915	100,000	125,000	25,000	25%	150,000	150,000	150,000	150,000
Corporate PILS Recoverable	511,562	759,334	—	—	—	—	—	—	—	—	—
Unbilled Revenue	4,783,498	7,103,557	6,450,000	5,500,000	5,500,000	—	—	5,500,000	5,500,000	5,500,000	5,500,000
	14,285,653	**17,007,810**	**16,059,017**	**13,750,000**	**16,558,839**	**2,808,839**	**20%**	**14,800,000**	**14,800,000**	**14,800,000**	**14,800,000**
Property, Plant & Equipment	58,854,036	61,152,857	60,519,253	65,893,792	68,733,208	2,839,416	4%	72,715,478	76,423,992	80,176,149	83,742,342
Other Assets											
Intangible Assets	1,806,282	2,228,625	2,293,142	2,614,822	4,394,822	1,780,000	68%	4,403,664	4,495,622	4,591,258	4,591,258
Future payments in lieu of income taxes	-3,239,959	-2,969,966	-1,706,586	-1,706,586	-2,969,966	-1,263,380	74%	-2,969,966	-2,969,966	-2,969,966	-2,969,966
Regulatory Assets	7,261,719	5,720,688	1,700,000	4,000,000	2,000,000	-2,000,000	(50%)	2,000,000	2,000,000	2,000,000	2,000,000
TOTAL ASSETS	**78,967,731**	**83,140,014**	**78,864,826**	**84,552,028**	**88,716,903**	**4,164,875**	**5%**	**90,949,176**	**94,749,648**	**98,597,442**	**102,163,634**
LIABILITIES											
Current Liabilites											
Bank Indebtedness	3,740,695	3,679,961	—	1,827,182	—	-1,827,182	(100%)	1,476,792	2,020,413	2,633,485	2,867,195
Accounts Payable & Accrued Liabilities	9,663,091	10,121,316	10,700,000	11,000,000	11,200,000	200,000	2%	11,400,000	11,600,000	11,800,000	12,000,000
Current Portion of Consumer Deposits	1,016,175	1,256,618	1,000,000	1,000,000	1,000,000	—	—	1,000,000	1,000,000	1,000,000	1,000,000
Current Portion of Long Term Loans	728,464	564,000	750,364	1,253,334	1,055,685	-197,649	(16%)	1,073,685	1,093,054	1,109,685	1,130,685
Dividends Declared	248,269	—	300,596	200,000	200,000	—	—	200,000	200,000	200,000	200,000
Promissory Note	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	—	—	15,600,000	15,600,000	15,600,000	15,600,000
Loan Advance		2,500,000	—	—	—	—	—	—	—	—	—
	30,996,695	**33,721,895**	**28,350,960**	**30,880,516**	**29,055,685**	**-1,824,831**	**(6%)**	**30,750,477**	**31,513,467**	**32,343,170**	**32,797,880**
Other Liabilites											
Unrealized loss on interest rate swap	-784,886	-454,755	938,948	-784,886	-454,755	330,131	(42%)	-454,755	-454,755	-454,755	-454,755
Deferred Revenue	2,914,627	3,284,439	3,102,394	3,369,015	3,617,164	248,149	7%	3,872,061	4,134,083	4,404,025	4,683,662
Employee Future Benefits	1,009,878	1,024,453	1,361,643	1,078,327	1,024,453	-53,874	(5%)	1,024,453	1,024,453	1,024,453	1,024,453
Long Term Debt											
Consumer Deposits over one year	980,367	631,651	400,000	400,000	400,000	—	—	400,000	400,000	400,000	400,000
RBC Loan - LT Portion	9,812,012	9,290,012	11,562,616	12,808,315	16,752,630	3,944,315	31%	15,678,945	17,085,891	18,476,206	19,862,152
TOTAL LIABILITIES	**10,792,379**	**13,775,800**	**17,365,600**	**16,870,771**	**21,339,492**	**4,468,721**	**26%**	**20,520,704**	**22,189,672**	**23,849,929**	**25,515,513**
EQUITY											
Share Capital - Common	9,468,388	9,468,388	9,468,388	9,468,388	9,468,388	—	—	9,468,388	9,468,388	9,468,388	9,468,388
Share Capital - Preferred	6,100,000	6,100,000	6,100,000	6,100,000	6,100,000	—	—	6,100,000	6,100,000	6,100,000	6,100,000
Retained Earnings	18,525,130	20,183,927	17,937,614	21,286,832	22,863,334	1,576,502	7%	24,219,603	25,588,117	26,945,951	28,391,850
Accumulated Other Comprehensive Income	-54,479	-109,996	-357,737	-54,479	-109,996	-55,517	102%	-109,996	-109,996	-109,996	-109,996
TOTAL EQUITY	**34,039,039**	**35,642,319**	**33,148,265**	**36,800,741**	**38,321,726**	**1,520,985**	**4%**	**39,677,995**	**41,046,509**	**42,404,343**	**43,850,242**
TOTAL LIABILITIES AND EQUITY	**78,967,731**	**83,140,014**	**78,864,826**	**84,552,028**	**88,716,903**	**4,164,876**	**5%**	**90,949,176**	**94,749,648**	**98,597,442**	**102,163,634**

FESTIVAL HYDRO INC.

Statement of Capital 2025 Budget

	YTD as at Dec 31, 2022	YTD Prelim. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2024	YTD Bdgt. as at Dec 31, 2025	2024 Bdgt to 2025 Bdg YTD Var$	2024 Bdgt to 2025 Bdg YTD Var%	YTD Bdgt. as at Dec 31, 2026	YTD Bdgt. as at Dec 31, 2027	YTD Bdgt. as at Dec 31, 2028	YTD Bdgt. as at Dec 31, 2029
DISTRIBUTION											
Distribution Overhead	919,529	1,027,272	1,090,350	1,207,254	1,500,715	293,461	24%	1,538,497	1,577,342	1,617,282	1,658,347
Underground Conductor and Devices	871,375	715,996	1,173,950	1,200,519	1,701,450	500,931	42%	1,729,595	1,754,103	1,788,185	1,822,949
Distribution Transformers	374,144	553,413	315,000	415,000	595,000	180,000	43%	612,850	631,236	650,173	669,678
Services	317,708	242,624	195,000	195,000	218,140	23,140	12%	222,503	226,953	231,492	236,122
Distribution Meters	397,955	433,583	335,000	400,000	1,427,297	1,027,297	257%	1,662,595	1,712,499	1,763,949	886,591
SCADA/Distribution Automation	33,563	120,308	75,000	76,500	141,500	65,000	85%	149,984	155,967	162,205	168,694
Tools and Miscellaneous Equipment	28,200	36,453	30,000	45,000	46,200	1,200	3%	47,436	48,709	50,020	51,371
TOTAL DISTRIBUTION	**2,942,474**	**3,129,649**	**3,214,300**	**3,539,273**	**5,630,302**	2,091,029	**59%**	**5,963,460**	**6,106,808**	**6,263,306**	**5,493,751**
OTHER CAPITAL											
Land and Buildings	365,904	1,060,506	918,000	2,165,000	505,000	-1,660,000	(77%)	315,000	535,000	270,000	440,000
Transformer Station	86,263	212,043	165,000	150,000	274,600	124,600	83%	272,600	278,632	289,497	298,397
Vehicles and Trailers	68,635	92,935	75,000	450,000	125,000	-325,000	(72%)	575,000	220,000	477,544	598,230
Computer Hardware and Software	254,790	842,078	641,775	1,412,667	1,201,636	-211,031	(15%)	361,115	458,321	476,654	495,720
Contributed Capital	221,461	-466,382	-400,000	-200,000	-325,000	-125,000	63%	-331,500	-338,130	-344,893	-351,790
TOTAL OTHER CAPITAL	**997,052**	**1,741,180**	**1,399,775**	**3,977,667**	**1,781,236**	**-2,196,431**	**(55%)**	**1,192,215**	**1,153,823**	**1,168,802**	**1,480,557**
TOTAL CAPITAL EXPENSE	**3,939,526**	**4,870,828**	**4,614,075**	**7,516,940**	**7,411,538**	**-105,402**	**(1%)**	**7,155,674**	**7,260,632**	**7,432,109**	**6,974,308**

FESTIVAL HYDRO INC.

Income Statement 2025 Budget

	YTD as at Dec 31, 2022	YTD Prelim. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2024	YTD Bdgt. as at Dec 31, 2025	2024 Bdgt to 2025 Bdg YTD Var$	2024 Bdgt to 2025 Bdg YTD Var%	YTD Bdgt. as at Dec 31, 2026	YTD Bdgt. as at Dec 31, 2027	YTD Bdgt. as at Dec 31, 2028	YTD Bdgt. as at Dec 31, 2029
REVENUE											
Service Revenue	70,315,230	75,549,794	90,812,198	73,237,405	77,842,377	4,604,973	6%	80,047,549	83,623,614	86,540,668	88,011,859
Cost of Power	58,141,145	62,051,846	77,636,844	59,529,328	61,867,250	2,337,923	4%	63,620,317	66,471,704	68,750,537	69,781,795
GROSS MARGIN (DISTRIBUTION REVENUE)	**12,174,085**	**13,497,948**	**13,175,354**	**13,708,077**	**15,975,127**	**2,267,050**	**17%**	**16,427,231**	**17,151,910**	**17,790,130**	**18,230,064**
Other Operating Revenue	1,122,786	1,067,928	1,114,397	1,053,436	1,063,970	10,534	1%	1,076,738	1,089,659	1,102,735	1,115,968
OPERATING & MAINTENANCE EXPENSE											
Transformer & Distribution Station Expense	239,484	419,509	337,650	343,730	435,217	91,487	27%	450,449	463,963	477,882	492,218
Distribution Lines & Services Overhead	1,677,230	1,711,863	1,789,355	1,961,284	2,078,381	117,097	6%	2,151,124	2,215,658	2,282,127	2,350,591
U/G Distribution Lines & Services	254,396	235,721	219,578	248,455	260,191	11,736	5%	269,298	277,377	285,698	294,269
Distribution Transformers	81,251	70,932	85,937	85,823	86,612	789	1%	89,643	92,333	95,103	97,956
Distribution Meters	444,351	394,578	431,921	460,545	493,508	32,963	7%	510,781	526,104	541,888	558,144
Customer Premises	206,830	216,533	222,258	252,148	268,438	16,290	6%	277,834	286,169	294,754	303,596
TOTAL OPERATING AND MAINTENANCE	**2,903,543**	**3,049,137**	**3,086,701**	**3,351,985**	**3,622,347**	**270,362**	**8%**	**3,749,129**	**3,861,603**	**3,977,451**	**4,096,775**
ADMINISTRATION											
Billing, Collecting & Meter Reading	1,283,486	1,491,620	1,401,088	1,527,185	1,707,271	180,086	12%	1,767,026	1,820,037	1,874,638	1,930,877
Administration	2,694,580	3,130,628	3,219,019	3,440,081	4,100,642	660,561	19%	4,244,165	4,413,931	4,634,628	4,866,359
TOTAL ADMINISTRATION	**3,978,065**	**4,622,248**	**4,620,107**	**4,967,267**	**5,807,914**	**840,647**	**17%**	**6,011,191**	**6,233,968**	**6,509,266**	**6,797,236**
Allocated Depreciation	-122,564	-114,241	-122,328	-135,373	-132,131	3,241	(2%)	-162,300	-196,206	-212,913	-220,807
TOTAL CONTROLLABLE COST	**6,759,045**	**7,557,144**	**7,584,479**	**8,183,879**	**9,298,129**	**1,114,250**	**14%**	**9,598,019**	**9,899,365**	**10,273,803**	**10,673,204**
					#DIV/0!						
NET INCOME BEFORE DEP'N, INTEREST & TAX	**6,537,826**	**7,008,732**	**6,705,272**	**6,577,634**	**7,740,968**	**1,163,334**	**18%**	**7,905,950**	**8,342,204**	**8,619,062**	**8,672,827**
Depreciation	2,505,726	2,619,161	2,685,888	2,800,946	3,117,122	316,176	11%	3,496,063	3,798,290	3,929,207	3,759,906
Interest Expense	1,655,362	2,052,489	1,597,036	2,118,661	2,311,763	193,102	9%	2,263,356	2,391,561	2,486,764	2,621,764
Interest Income	-82,058	-282,176	-33,000	-320,000	-150,000	170,000	(53%)	-150,000	-150,000	-150,000	-150,000
NET INCOME BEFORE SWAP, ICM & PBA & INC TAXES	**2,458,796**	**2,619,258**	**2,455,348**	**1,978,027**	**2,462,083**	**484,056**	**24%**	**2,296,532**	**2,302,354**	**2,353,090**	**2,441,157**
Current Tax	104,400	240,000	346,000	171,970	295,252	123,282	72%	349,933	343,510	404,927	404,928
NET INCOME BEFORE SWAP & ICM	**2,354,396**	**2,379,258**	**2,109,348**	**1,806,057**	**2,166,831**	**360,774**	**20%**	**1,946,599**	**1,958,844**	**1,948,163**	**2,036,229**
Unrealized Gain/Loss on Swap	-1,723,834	330,131	—	—	—	—	—	—	—	—	—
Marketable Security - recorded as OCI	-303,258	55,517	—	—	—	—	—	—	—	—	—
NET INCOME	**4,381,488**	**1,993,610**	**2,109,348**	**1,806,057**	**2,166,831**	**360,774**	**20%**	**1,946,599**	**1,958,844**	**1,948,163**	**2,036,229**

FESTIVAL HYDRO INC.

Cash Flow 2025 Budget

	YTD as at Dec 31, 2022	YTD Prelim. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2023	YTD Bdgt. as at Dec 31, 2024	YTD Bdgt. as at Dec 31, 2025	2024 Bdgt to 2025 Bdg YTD Var$	2024 Bdgt to 2025 Bdg YTD Var%	YTD Bdgt. as at Dec 31, 2026	YTD Bdgt. as at Dec 31, 2027	YTD Bdgt. as at Dec 31, 2028	YTD Bdgt. as at Dec 31, 2029
Cash from Operations											
Net Income	4,381,488	1,993,610	2,109,348	1,806,057	2,166,831	360,774	20%	1,946,599	1,958,844	1,948,163	2,036,229
Depreciation	2,505,726	2,619,161	2,685,888	2,800,946	3,117,122	316,176	11%	3,496,063	3,798,290	3,929,207	3,759,906
Amortization of deferred revenue in other revenue	-358,598	369,812	-79,369	-76,869	-76,851	18	(0%)	-76,603	-76,108	-74,950	-72,154
Unrealized loss on interest rate swap	-1,723,834	330,131	—	—	330,131	330,131	—	—		—	—
Decrease/(Increase) in Receivables	-179,111	-760,695	1,100,000	—	-1,000,000	-1,000,000	—	—	—	—	—
Decrease/(Increase) in Inventory	-14,081	-34,479	—	—	—	—	—	—	—	—	—
Decrease/(Increase) in Prepaids	126,840	17,850	—	-425,000	—	425,000	(100%)	—	—	—	—
Decrease/(Increase) in Due from FHSI	210,656	153,502	68,490	-50,000	-25,000	25,000	(50%)	-25,000	—	—	—
Decrease/(Increase) in PILS	-155,505	-247,771	—	750,000	—	-750,000	(100%)	—	—	—	—
Decrease/(Increase) in Unbilled Revenues	447,273	-2,320,059	-450,000	500,000	—	-500,000	(100%)	—	—	—	—
Decrease/(Increase) in Future Tax (offsetting entry in pa	130,039	-269,993	—	—	1,263,380	1,263,380	—	—	—	—	—
Decrease/(Increase) in Regulatory Assets	-2,664,508	1,541,031	—	2,000,000	2,000,000	—	—	—	—	—	—
Increase/(Decrease) in Payables	-1,257,307	458,225	600,000	100,000	200,000	100,000	100%	200,000	200,000	200,000	200,000
Increase/(Decrease) in Deposits	232,689	-108,272	-100,000	—	—	—	—	—	—	—	—
Increase/(Decrease) in Employee Future Benefits	-351,765	14,575	—	—	-53,874	-53,874	—	—	—	—	—
Contributed Capital	483,203	466,382	400,000	200,000	325,000	125,000	63%	331,500	338,130	344,893	351,790
Net Cash Provided	**1,813,204**	**4,223,008**	**6,334,357**	**7,605,134**	**8,191,223**	**586,089**	**8%**	**5,872,559**	**6,219,155**	**6,347,313**	**6,275,772**
Cash from Financing											
Loan Repayments	-707,719	-686,465	-727,496	-750,364	-1,253,334	-502,970	67%	-1,055,685	-1,073,685	-1,093,054	-1,093,053
Loan Advances		2,500,000	—	2,500,000	5,000,000	2,500,000	100%	—	2,500,000	2,500,000	2,500,000
Cash Used - Capital Expenditures	-3,939,526	-5,337,210	-5,014,075	-7,716,940	-7,736,538	-19,598	0%	-7,487,174	-7,598,762	-7,777,001	-7,326,099
Cash Used - Dividends paid current year	-390,330	-638,599	-390,330	-390,330	-390,330	—	—	-390,330	-390,330	-390,330	-390,330
Cash Used - Dividends declared in prior year	-500,556	—	-235,645	-200,000	-200,000	—	—	-200,000	-200,000	-200,000	-200,000
Net Cash Used	**-5,538,131**	**-4,162,274**	**-3,867,546**	**-6,557,634**	**-4,580,202**	**1,977,432**	**(30%)**	**-9,133,189**	**-6,762,777**	**-6,960,385**	**-6,509,482**
Increase (Decrease) in Cash Position	**-3,724,927**	**60,734**	**2,466,811**	**1,047,500**	**3,611,021**	**2,563,521**	**245%**	**-3,260,631**	**-543,621**	**-613,072**	**-233,709**
Bank Indebtedness, Beg of Period	**-15,769**	**-3,740,696**	**-634,709**	**-2,874,682**	**-1,827,182**	**2,874,682**	**(100%)**	**1,783,839**	**-1,476,792**	**-2,020,413**	**-2,633,485**
Bank Indebtedness, End of Period	**-3,740,696**	**-3,679,961**	**1,832,102**	**-1,827,182**	**1,783,839**	**1,827,182**	**(100%)**	**-1,476,792**	**-2,020,413**	**-2,633,485**	**-2,867,195**

Key Financial Ratios:	Actual Ratio	Actual Ratio	Actual Ratio	Actual Ratio	Actual Ratio			Actual Ratio	Actual Ratio	Actual Ratio	Actual Ratio
RBC Compliance Ratio - Funded Debt to Total Capital	0.48	0.46	0.47	0.47	0.47			0.47	0.47	0.48	0.48
Less than 0.65											
Debt to Equity Test	32:68	29:71	29:71	32:68	33:67			33:67	34:66	36:64	36:64
Target: less than 75:25											
Debt Service Ratio	1.95	1.98	2.01	1.58	1.81			1.86	1.89	1.91	1.86
Target: not less than 1.30X											

Funded Debt to Total Capital Ratio									
Current portion of LT Debt	728,464	564,000	750,364	1,253,334	1,055,685	1,073,685	1,093,054	1,109,685	1,130,685
ST & LT Consumer Deposits	1,996,542	1,256,618	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000
Shareholder Loan	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,001
RBC Overdraft/other borrowings	3,740,695	3,679,961	-	1,827,182	-	1,476,792	2,020,413	2,633,485	2,867,195
Royal Bank Loan	9,812,012	9,290,012	11,562,616	12,808,315	16,752,630	15,678,945	17,085,891	18,476,206	19,862,152
I/O Loan (L.T.)	-	-	-	-	-	-	-	-	1
Funded Debt	**31,877,713**	**30,390,591**	**29,312,980**	**32,888,831**	**34,808,315**	**35,229,422**	**37,199,358**	**39,219,376**	**40,860,034**
Current portion of LT Debt	728,464	564,000	750,364	1,253,334	1,055,685	1,073,685	1,093,054	1,109,685	1,130,685
ST & LT Consumer Deposits	1,996,542	1,256,618	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000
Shareholder Loan	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,000	15,600,001
RBC Overdraft/other borrowings	3,740,695	3,679,961	-	1,827,182	-	1,476,792	2,020,413	2,633,485	2,867,195
Royal Bank Loan	9,812,012	9,290,012	11,562,616	12,808,315	16,752,630	15,678,945	17,085,891	18,476,206	19,862,152
I/O Loan (L.T.)	-	-	-	-	-	-	-	-	1
Share Capital	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,389
Equity (w/o OCI)	18,525,130	20,183,927	17,937,614	21,286,832	22,863,334	24,219,603	25,588,117	26,945,951	28,391,850
Total Capital	**65,971,231**	**66,142,906**	**62,818,982**	**69,744,051**	**73,240,037**	**75,017,413**	**78,355,863**	**81,733,715**	**84,820,272**
Funded Debt to Total Capital Ratio	**0.48**	**0.46**	**0.47**	**0.47**	**0.48**	**0.47**	**0.47**	**0.48**	**0.48**
Debt to Equity Ratio									
Customer Deposits	1,996,542	1,256,618	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000	1,400,000
Current portion of LTD	728,464	564,000	750,364	1,253,334	1,055,685	1,073,685	1,093,054	1,109,685	1,130,685
RBC Construction Loan	9,812,012	9,290,012	11,562,616	12,808,315	16,752,630	15,678,945	17,085,891	18,476,206	19,862,152
RBC Overdrafts	3,740,695	3,679,961	-	1,827,182	-	1,476,792	2,020,413	2,633,485	2,867,195
I..O. Long term portion	-	-	-	-	-	-	-	-	1
Total Liabilities	**16,277,713**	**14,790,591**	**13,712,980**	**17,288,831**	**19,208,315**	**19,629,422**	**21,599,358**	**23,619,376**	**25,260,033**
Share Capital	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,388	15,568,389
Equity	18,525,130	20,183,927	17,937,614	21,286,832	22,863,334	24,219,603	25,588,117	26,945,951	28,391,850
Total Equity	**34,093,518**	**35,752,315**	**33,506,002**	**36,855,220**	**38,431,722**	**39,787,991**	**41,156,505**	**42,514,339**	**43,960,239**
Debt to Equity Ratio	**0.68**	**0.71**	**0.71**	**0.68**	**0.67**	**0.67**	**0.66**	**0.64**	**0.64**
Debt Service Ratio									
(DSCR= EBITDA/DSR)									
Net income	4,381,488	2,379,258	2,109,348	1,806,057	2,166,831	1,946,599	1,958,844	1,948,163	2,036,229
Interest Charges	1,655,362	2,052,489	1,597,036	2,118,661	2,311,763	2,263,356	2,391,561	2,486,764	2,621,764
Income based taxes	104,400	240,000	346,000	171,970	295,252	349,933	343,510	404,927	404,928
Depreciation/Amortization	2,505,726	2,619,161	2,685,888	2,800,946	3,117,122	3,496,063	3,798,290	3,929,207	3,759,906
Employee future benefit acc	-303,258	55,517	0	0	0	0	0	0	0
Unrealized gain on swap	-1,723,834	330,131	0	0	0	0	0	0	0
EBITDA	**6,619,884**	**7,676,556**	**6,738,272**	**6,897,634**	**7,890,968**	**8,055,950**	**8,492,204**	**8,769,062**	**8,822,827**
Interest Expense (excl I.O. & RBC)	1,655,362	2,052,489	1,597,036	2,118,661	2,311,763	2,263,356	2,391,561	2,486,764	2,621,764
Repayment of RBC overdraft									
Deposits due under 1 year	1,016,175	1,256,618	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
RBC & IO Principal pymt in 1 year	728,464	564,000	750,364	1,253,334	1,055,685	1,073,685	1,093,054	1,109,685	1,130,685
RBC & IO Interest pymts in 1 year									
Total Debt Service	**3,400,001**	**3,873,107**	**3,347,400**	**4,371,995**	**4,367,448**	**4,337,041**	**4,484,615**	**4,596,449**	**4,752,449**
DSCR	**1.95**	**1.98**	**2.01**	**1.58**	**1.81**	**1.86**	**1.89**	**1.91**	**1.86**

To:	Audit Committee
Agenda:	Item 12. 2025 Budgets
Date:	January 30, 2024
From:	Alyson Conrad, CFO Bryon Hartung, VP Engineering and Operations
Re:	2025 Capital, Operation, Maintenance and Administration Budget

Previously, FHI filed its detailed Cost of Service rate application for rates effective January 1, 2015. In the intervening years, FHI files a Price Cap IR application which allows for an increase in distribution rates based on an inflationary factor, less the LDC's specific productivity factor. In 2023 we moved to an Annual IR application which allows for an increase in distribution rates based on an inflationary factor less the highest productivity factor. Currently, FHI is in the process of preparing its Cost of Service (COS) application for rates effective January 1, 2025. The COS considers 2025 as the 'test year' which means that this is the year that capital and OM&A are reviewed in significant detail. This is why this budget is being presented for review in January instead of at the typical fall time frame. The final draft of the 2025 budget will be presented to the FHI Board after settlement with the OEB in fall of 2024.

In terms of Capital, as part of the 2015 COS rate application, FHI filed a Distribution System Plan (DSP) which provided, in detail, the planned capital expenditures for 2015 and for the following four years (2016 through 2019). The OEB approved the 2015 expenditures as presented. Subsequently, an additional five-year Capital Plan was drafted for 2020 to 2024. For the 2025 COS, a new five-year Capital Plan has been incorporated into this budget and will be presented in the Distribution System Plan (DSP).

Capital Budget for 2025

The 2025 Budget for capital expenditures is $7,411,538 (net of budgeted capital contributions of $325,000). The proposed budget is based on the latest 5-year Capital Plan included in the DSP which also contains the remainder of the new Enterprise Resource Planning (ERP) software implementation and smart meter redeployment (AMI 2.0).

From the gross capital expenditures of $7.74M (excludes contributed capital), $6.37M has been allocated to the replacement of depreciated distribution system plant, fleet vehicles and equipment and facilities. In addition, $1.02M has been allocated for growth related projects (new/upgraded services, customer driven work, transformers, and meters) and a total of $1.34M has been allocated for implementing new technology.

The following table puts the Capital Budget in historical perspective, noting the number of customers associated with each budget year.

The total 2025 Capital expenditure amount is $325.14/customer, compared to 2024 budget at a cost of $332.59/customer. The 2025 budgeted cost per customer is relatively consistent compared to 2024.

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Budget	2025 Budget
Total Capital	$2,758,937	$3,366,755	$3,939,526	$4,870,828	$7,516,940	$7,411,538
Customer Base	21,717	21,996	22,082	22,451	22,601	22,725
Capital $/Customer	$127.04	$153.06	$178.40	$216.95	$332.59	$326.14

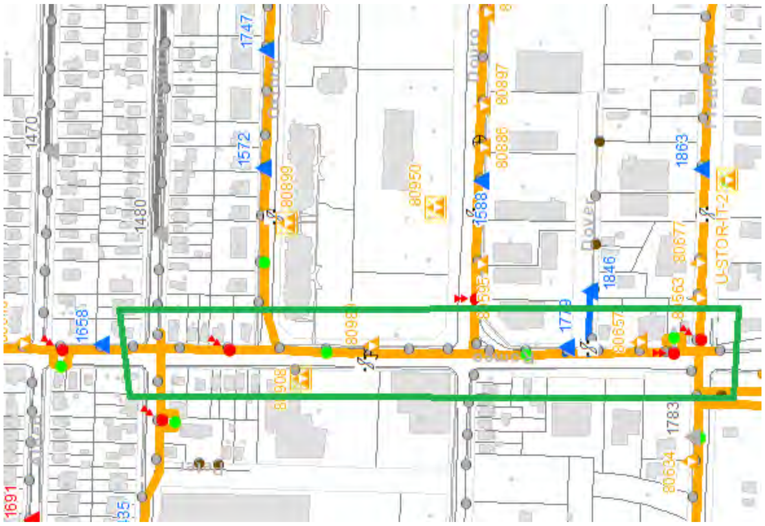
The following explanations and attached tables will provide greater detail of the specific projects.

Replacement and Reliability Projects

These are projects initiated by the engineering department, to address system problems, reduce losses, improve safety, and decrease outages. They include projects such as switchgear replacements, cable replacements, line rebuilds, and insulator replacements.

Overhead

Stratford – Romeo St. S – Frederick St to Brunswick St.



The scope of this project is the replacement of 20 concrete poles (new poles to be concrete) and overhead primary conductor on Romeo St. S. from Frederick St to Brunswick St.. The project spans approximately 450 meters. Primary and secondary conductors, as well as transformers are to be replaced as part of this project. The majority of poles, primary conductors and insulators are over 50 years old and have been identified by the asset condition assessment as being in poor or very poor condition.

The cost of this project is estimated at $312,500.

Stratford – Louise St – Brydges St. to Blake St.

The scope of this project is a replacement of 5 concrete poles (new poles to be concrete) on Louise St. from Brydges St. to Blake St. The project spans approximately 125 meters. New conductors will be installed as part of this project. The majority of poles, primary conductors and insulators are over 50 years old and have been identified by the asset condition assessment as being in poor condition.

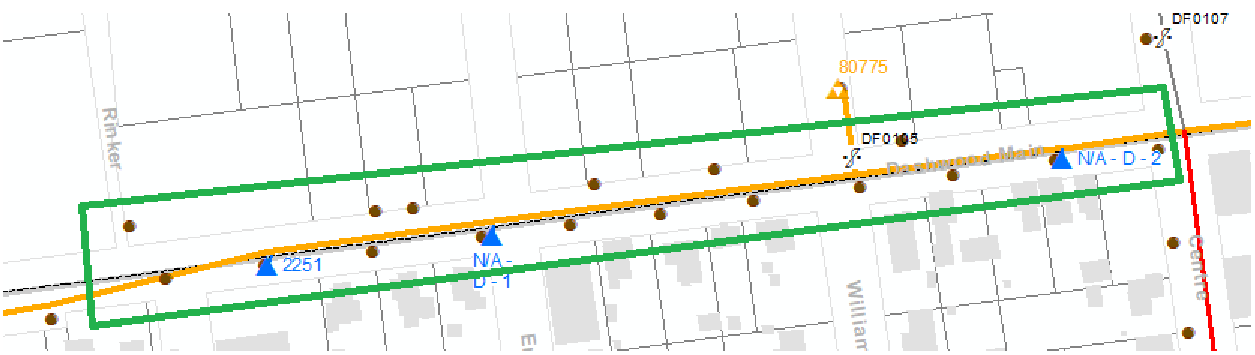
The cost of this project is estimated at $47,500.

Stratford – Nelson St. – Walnut St. to Ash St.

The scope of this project is a replacement of 11 wood poles (new poles to be concrete) on Nelson St. from Walnut St. to Ash St. The project spans approximately 280 meters. New conductors and transformers will be installed as part of this project. The majority of poles, primary conductors and insulators are over 45 years old and have been identified by the asset condition assessment as being in poor or very poor condition.

The cost of this project is estimated at $69,000.

Dashwood – Highway 83 from western town boundary to Centre St.

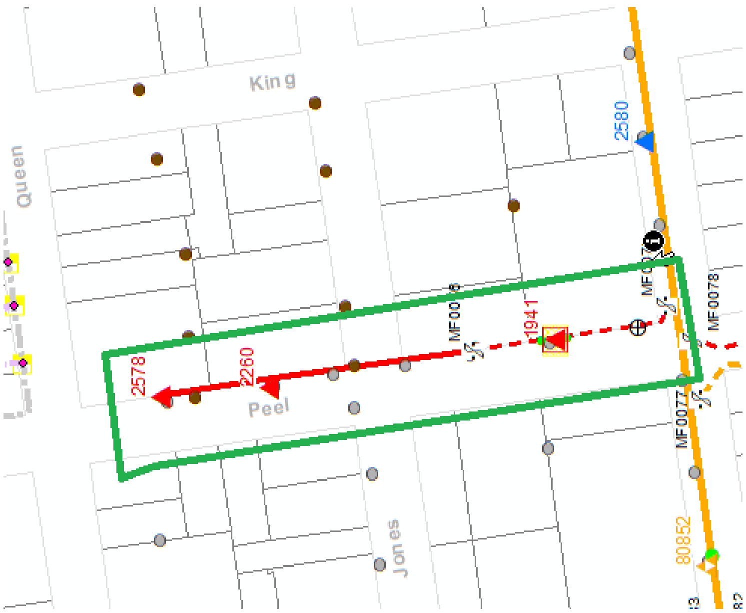


The scope of this project is the replacement of 17 wood poles (new poles to also be wood) and overhead primary conductor on Highway 83 from the western boundary of Dashwood to Centre St. This project is being done in coordination with the Township for a road reconstruction project and is a two part project, with the first phase being completed in 2024. The project spans approximately

400 meters. Primary and secondary conductors are to be replaced as part of this project. While the main purpose of this project is to relocate for the new roadway, this project also provides the additional benefit of replacing numerous poles, primary conductors and insulators that are over 50 years old and have been identified by the asset condition assessment as being in poor or very poor condition.

The cost of this project is estimated at $189,000.

St. Mary's – Peel St. S – Queen St. to Elgin St.



The scope of this project is a replacement of 2 poles along Peel St. in St. Mary's between Queen St. and Elgin St as well as upgrading the pole line from 1-phase to 3-phase. The project spans approximately 100 meters. This new three phase line is being built to provide a tie to many of the businesses in St. Mary's downtown core that currently have no backup feed. Existing conductor and transformers will be re-used, as well as poles that are suitable for three phase circuits. The two poles being replaced have been identified by the asset condition assessment as being in poor condition and are not suitable for a three phase circuit.

The cost of this project is estimated at $68,000.

Seaforth – Birch St.

The scope of this project is a replacement of 5 wood poles and the addition of 7 new wood poles on Birch St. This is being done to support the long term upgrade of Seaforth from 4kV to 27.6kV and to replace 5 poles identified by the asset condition assessment as being in poor condition. The project spans approximately 320 meters. New primary conductor and new dual voltage transformers will be installed where applicable.

The cost of this project is estimated at $116,000.

Seaforth – Railway Crossing – Main St and Crombie St.

The scope of this project is a replacement of 4 wood poles along the railway corridor between Main St. and Crombie St. This is being done to support the long term upgrade of Seaforth from 4kV to 27.6kV and also replaces 3 poles identified by the asset condition assessment as being in poor or fair condition. The project spans approximately 120 meters. New primary conductor will be installed as part of this project as well.

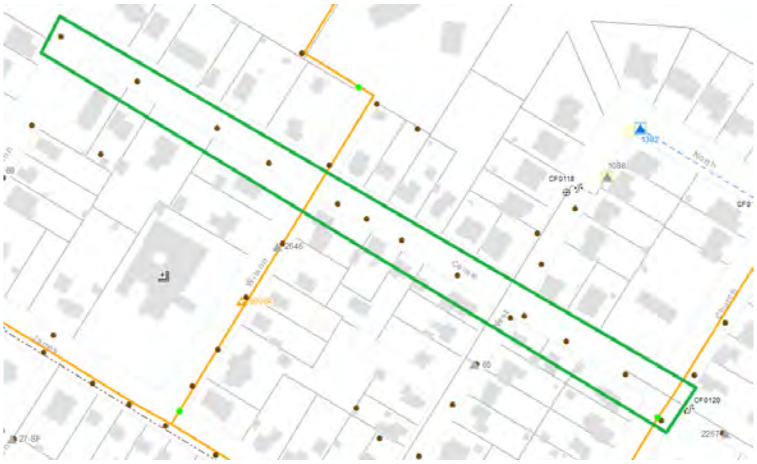
The cost of this project is estimated at $62,000.

Seaforth – High St. – Huron St to Market St.

The scope of this project is a replacement of 4 concrete poles (replaced with wood) on High St. The project spans approximately 130 meters. New secondary conductors will be installed as part of this project. The majority of poles, conductors and insulators are over 50 years old and have been identified by the asset condition assessment as being in poor condition.

The cost of this project is estimated at $16,000.

Seaforth – Centre St. – Ann St to Church St.



The scope of this project is a replacement of 8 wood poles on High St. The project spans approximately 380 meters. New secondary conductors will be installed as part of this project. The majority of poles, conductors and insulators are over 70 years old and have been identified by the asset condition assessment as being in very poor condition.

The cost of this project is estimated at $36,000.

Hensall Back Yard – Brock St to Elizabeth St.

The scope of this project is a replacement of 6 wood poles in back yards. The project spans approximately 200 meters. New secondary conductors will be installed as part of this project. All poles, conductors and insulators are over 50 years old and have been identified by the asset condition assessment as being in poor condition.

The cost of this project is estimated at $73,750.

St. Mary's – Reinsulate Poles

The focus of this project remains in St. Mary's in 2025 to continue addressing momentary outages from animal contacts in this area.

This scope of this project is to install fiberglass extension brackets, while also upgrading the insulators to a higher voltage class. In addition, replacing any metallic fasteners as a means of increasing clearances on the concrete poles as inspections have noted that clearance from primary conductor to concrete poles are currently insufficient to prevent squirrel contacts. The scope of the project will also include the installation of animal guards on or around poles that are difficult to re-insulate. The focus will continue to be on heavily treed areas in St. Mary's where 3 phase circuits are present.

The cost of this project is estimated at $75,000.

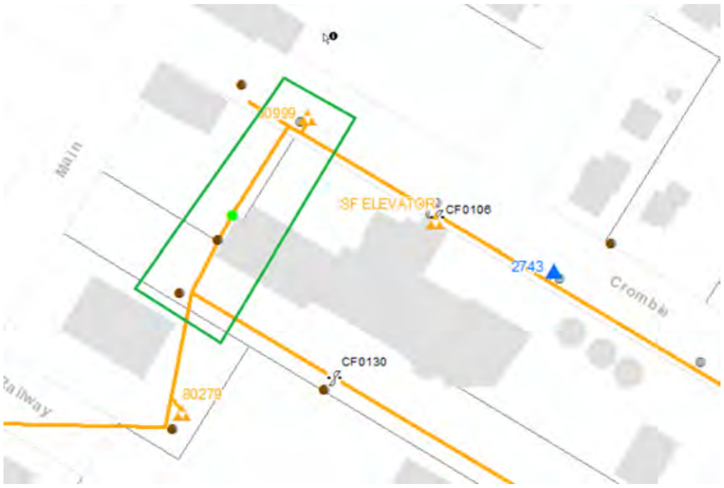
Underground

Seaforth – Goderich St. – Coleman Dr. to Centennial St.

The scope of the project includes the removal of overhead primary and secondary backlot poles that currently feed 9 customers on and feeding them underground on the pole line on Goderich St. This eliminates the need to maintain and replace backlot infrastructure in the future and removes 8 poles that are over 60 years old that have been identified in the asset condition assessment as being in very poor condition.

The cost of this project is estimated to be $83,100.

Seaforth – Railway Crossing – Main St. and Crombie St.



The scope of this project is a replacement of the existing overhead rail crossing Main St. and Crombie St. with an underground crossing. This is being done to support the long-term upgrade of Seaforth from 4kV to 27.6kV. The project includes the installation of 80m of three phase underground primary conductor and the associated civil work to install ducts. This crossing is being replaced as underground as the existing crossing cannot be efficiently rebuilt in the available space as overhead and meet current standards for clearances and support.

The cost of this project is estimated to be $77,400.

Seaforth – Oak St. and Birch St. Tie

The scope of this project is a replacement of existing single phase conductor with a three phase underground primary conductor tie between Oak St. and Birch St. This is being done to support the long term upgrade of Seaforth from 4kV to 27.6kV and replaces the single phase infrastructure identified by the asset condition assessment as being in poor condition. The project includes the installation of 190m of three phase underground primary conductor and the associated civil work to install ducts.

The cost of this project is estimated to be $101,200.

Stratford – Barron St. Townhomes

The scope of the project includes the replacement of approximately 420m of single phase radial underground primary conductors and transformers that service residential customers on Barron St. in Stratford. The underground cable is over 30 years old and has been identified by the asset condition assessment as being in poor condition. This project will also allow for future looping of conductors to mitigate prolonged outages due to equipment issues or maintenance.

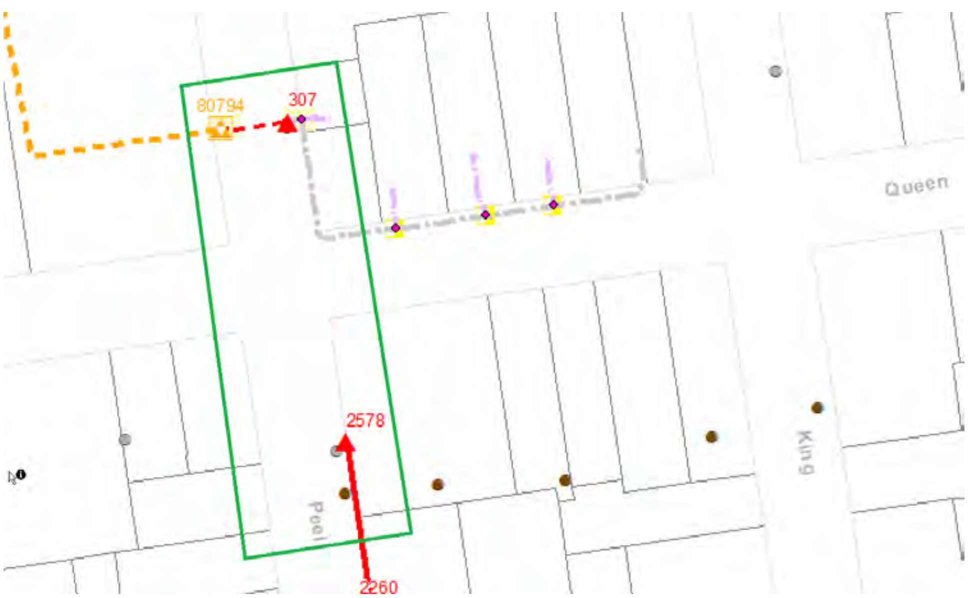
The cost of this project is estimated to be $91,000.

Stratford – 60 Erie St. to 100 Erie St.

The scope of the project includes the replacement of approximately 270m of underground primary conductor which services commercial customers on Erie St. in Stratford. The underground cable is over 35 years old and has been identified by the asset condition assessment as being in poor condition.

The cost of this project is estimated to be $29,400.

St. Marys – Peel St and Queen St E.



The scope of the project includes the addition of approximately 100 meters of three phase underground primary conductors and the associated civil work to install ducts. This new three phase tie is being built in conjunction with the overhead 1-phase to 3-phase upgrade on Peel St. and will provide a tie to many of the businesses in St. Mary's downtown core that currently have no backup feed.

The cost of this project is estimated to be $54,000.

St. Marys – Maxwell St from Dunsford Cr to Oakwood Crt

The scope of the project includes the replacement of approximately 1.4km of single phase underground primary conductors and transformers that service residential customers on Maxwell St., White Crt. and Oakwood Crt. In St. Marys. This project will add ducts to enable the looping of underground cables on White Crt. and Oakwood Crt. to provide redundancy in this area for outage and maintenance purposes. The underground cable is over 30 years old and has been identified by the asset condition assessment as being in poor condition. This is year two of a multi year project on Maxwell St to update the entire subdivision.

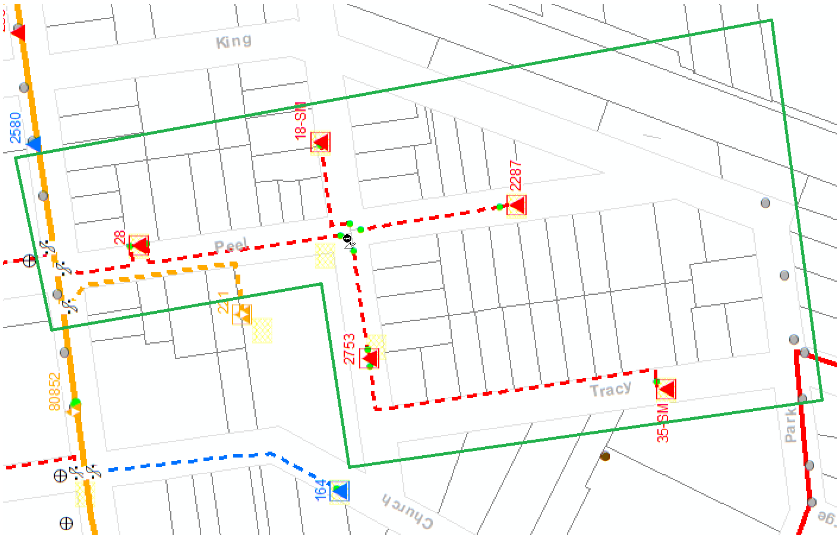
The cost of this project is estimated to be $243,900.

St. Marys – Ingersoll St Switchgear cable replacement

The scope of the project includes the replacement of approximately 275m of three phase underground primary conductors as well as the associated civil work to install ducts that feed a switchgear on Ingersoll St. This is being done in parallel with the switchgear replacement as the current cables do not have enough length to be re-used and are approximately 25 years old, making replacement the preferred option, with the added benefit of the new cables being in duct that can be re-used in the future.

The cost of this project is estimated to be $103,400.

St. Marys – Peel St S – Elgin St to Park St



The scope of the project includes the replacement of approximately 800 metres of single phase underground primary conductors and transformers as well as the associated civil work to install ducts, that service residential customers on Peel St. and Tracy St in St. Mary's. This area is also radial and a new loop will be established as part of this project at Tracy and Park St. to provide redundant feeds to the area. The underground cable is over 30 years old and has been identified by the asset condition assessment as being in poor condition.

The cost of this project is estimated to be $267,250.

Padmounted Switchgear Replacements

Before 2012 all padmounted switchgear installations were live front design. These installations had several inherent issues associated with them including: the possibility of animal and vegetation contact and personnel safety. FHI conducts regular inspections of our padmounted switchgear including yearly infrared surveys to identify any potential issues. Several years ago, FHI started a capital program to begin phasing out live front units in favour of dead front units or through system design changes that make the padmounted switchgear redundant and therefore they are removed from service not replaced.

The typical life expectancy for padmounted switchgear is 30 years. In the case of assets such as transformers FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. This is not the case for switchgear, as the inherent design flaws make it desirable to replace these units as soon as they reach the end of their useful life.

St. Mary's - 2 Switchgears To Be Replaced

As part of the 2025 budget the plan is to replace 2 more switchgears with new units. After 2025 there are planned to be two 15kV livefront, padmounted switchgear units in service in St. Mary's, which will be replaced in 2026, completing the program.

The cost of this project is estimated to be $244,200.

Transformers

This section accounts for transformers needed due to load growth, replacements, conversions, emergency stock and new developments. This amount is higher than previous years due to the increase in rebuild projects. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

The proposed transformer budget for 2025 is estimated at $595,000.

Miscellaneous Projects & Capital Additions

Miscellaneous projects are work that is unbudgeted but requires completion in the calendar year including: unsafe infrastructure requiring immediate replacement, cable failures, rusted padmount transformers, etc. which are typically found during inspections or unplanned system events. This budget item is meant to deal with immediate system issues. Over the last few years, dozens of poles have been replaced as part of this program. All wooden poles in FHI's service territory were tested in 2022 and 2023 to prepare for FHI's upcoming Cost of Service application. It is anticipated that in total approximately 15-20 poles will be replaced as part of this program with the focus being on those that were identified as lower risk from the previous years' inspections or that Engineering or Operations staff have identified as potential hazards throughout site visits or customer inquiries.

Capital Additions are customer driven work including pole line extensions, transformer installations, subdivision work etc. This budget item is completely customer driven and both sections are largely based on historical spending and information from developers available at the time of budgeting. These budgets take into account the previous five-year historical average spending and any known upcoming projects that may cause deviations from historical spending averages.

The proposed miscellaneous projects and capital additions budget for 2025 is estimated at $348,965 and $356,600 respectively.

New and Upgraded Services

Capital costs associated with the connection of new or upgraded residential and commercial secondary services. This section is customer driven and based on historical spending and any known upcoming projects.

The proposed new and upgraded services budget for 2025 is estimated at $218,140.

Metering

This value takes into account historical growth rates and potential meter replacements for residential, commercial and industrial installations. Investments will also be made into primary metering equipment including meters and instrument transformers to be used for replacement and spares. $1,276,147 has also been allocated in 2025 to begin the process of mass deployment of FHI's Smart Meter 2.0 solution. This includes the purchase and installation of field network devices as well as approximately 4,000 smart meters. The mass deployment is expected to continue through to 2029 when the project would be complete and spending would retreat to previous levels.

The proposed metering budget for 2025 is $1,427,297.

Transformer Station

In 2025 the majority of the spend will be on installing the replacements of the T1 Primary metering units, removing the ones from service that caused a catastrophic failure and corresponding outage in 2023. There is also money budgeted to replace the online oil monitors on the power transformers which give insight and early warning should an internal issue start to form within the transformers.

The proposed transformer station budget for 2025 is $274,600.

Distribution Stations

No capital work is planned for the Distribution Stations in Seaforth in 2025.

Fleet

One new pickup truck to replace truck 19 (2010) and one new forklift to replace the existing one is included in the capital plan for purchase in 2025. These will both go for tender in Q4 of 2024.

The proposed fleet budget for 2025 is $125,000.

Computer Equipment/Hardware

Spending for computer equipment and hardware in 2025 will be focused on lifecycle items such as laptop and mobile device replacement. As well, server infrastructure for OT will be refreshed to enhance capabilities and address end-of-life for support.

The proposed computer equipment/hardware budget for 2025 is $296,636.

Tools

Most of the purchases in this category are for expected replacements of existing tools and equipment as they reach end of life.

The proposed tools and miscellaneous equipment budget for 2025 is $46,200.

Land and Buildings

The Land and Buildings budget includes items related to the Administration Building and various Service Centre projects.

Admin building improvements include the replacement of the entire roof based on age and a recent 2023 report stating the roof should be replaced in 1-2 years. This is expected to provide a 15-20 year life and will also include the installation of proper sloping on the roof to assist with drainage. This is estimated at $400,000.

2025 Investments for the Service Centre include $20,000 for general upkeep of the building as well as the replacement of yard lights for $35,000.

The proposed lands and buildings budget for 2025 is $505,000.

Replacement

Replacement projects are selected using the inputs of the asset management process and are prioritized based on corporate objectives, looking to keep system conditions stable to slightly improving over time. Most budget ID's contain some element of replacement projects, excluding the customer driven sections.

The proposed replacement projects budget for 2025 is $6.367 million dollars.

GIS Services

External GIS services have been capitalized in the amount of $100,000. This will be utilized throughout various distribution projects to support asset data management. This budget amount is also included in the Replacement figure above.

The proposed GIS services budget for 2025 is $100,000.

Growth Related Work

This work is customer driven and the growth rates of the communities in the FHI service territory in 2025 are expected to be consistent with historical 5 year averages.

The proposed new and upgraded residential and commercial developments budget for 2025 is estimated at $1.023 million dollars.

New Technology

Technology spending for 2025 is primarily focused on ERP and Operational Technology (OT) systems.

ERP Replacement - The new ERP project will kick-off in 2024 and span both the 2024 and 2025 budget years. This is a significant project which will substantially improve capabilities and efficiency while dealing with the risk of lack of support and obsolescence of the current Daffron system. $875,000 has been budgeted for this project in 2025.

OT System Review - The design and security of OT systems will be renewed in 2025 based on the strategic plan to be delivered in 2024. The goal would be to complete the first phase of this plan within the budget year. This project will position FHI well as the OEB Cybersecurity framework and its insurer starts to address OT and supply chain risks. As well, it will provide valuable support for the AMI Refresh Project. $204,303 has been budgeted for this project and it is planned to be completed in 2025.

SCADA - SCADA projects include projects involving the installation of additional Fault Current Indicators (FCI's) in various locations in the distribution system as well as the installation of a new recloser within Stratford to assist in sectionalizing customers during outages, minimizing customers impacted. The SCADA budget is planned at $141,500.

FHI will also be implementing a Privileged Access Management solution to improve our cybersecurity capabilities. This will allow us to govern remote and administrator in a much more dynamic fashion, allowing us to tighten security across the network.

The proposed new technology budget for 2025 is $1,343,136.

2024 Operating Budget

Built into revenue is a preliminary estimate of expected revenues. This number will change depending on the final revenue requirement approved the OEB through the COS.

Controllable costs are budgeted at 13.6 % higher than the 2024 budget amount. 2025's budget includes a full staff complement including overlap for planned retirements and a new billing coordinator to assist in maintaining the new CIS. More details between 2024 and 2025 budget are included below. Note that labour has been budgeted based on specific retirements/new hires/grid movements and expected inflationary increases or planned inflationary increases as driven by the union agreement and wage analysis for non-union positions.

Distribution Revenue:

The 2025 distribution revenues are estimated based on preliminary expenses built into the COS. COS revenues consider load and customer forecasts. The revenues are derived by considering OM&A costs, amortization, PILS, deemed interest, working capital and rate of return. These will all be probed as part of the COS filing and will result in a final revenue requirement. This value will likely change throughout the Application process.

Other Operating Revenue

Other operating revenue is budgeted to increase $11K from the 2024 budget amount. 2025 was budgeted to remain relatively flat with minor inflationary increases. There are no new revenue streams projected in FHI for 2025.

Controllable Costs

The total Operating & Maintenance Budget for 2025 is $3.6M which is $270K more than the 2024 budget amount. The 2025 budget includes the following:

- Renewal of the transformer maintenance contract which is anticipated to increase by $70K.
- $30K increase in the tree trimming budget which was guided by the customer engagement for the COS.
- $25K for SCADA enhancements including contractor costs and firmware upgrades to distribution automation devices.
- $30K for vehicle parts and contract labour since this contract will be renewed and have anticipated increases.
- The remainder are staffing costs, benefits and inflationary increases.

The total Administration Budget for 2024 is $5.8M which is $841K greater than the 2024 budget. This accounts for increases to the following:

- $240K increases for operating costs related to large software projects including a full year of CIS operating costs, a partial year of ERP costs and AMI operating costs.
- $100K for 1/5th of total costs related to the Cost of Service, these costs are amortized over a 5 year period and will be approved in the COS.
- $50K for Regulatory Contract labour for the shared service with ERTH. This cost was mostly built into the COS costs in 2023-2024 but will be expensed in 2025.
- $385K for labour, benefits and professional development increases as well as includes the new billing coordinator to assist with billing services and will decrease the risk of reliance on one billing employee. A portion of these services were outsourced prior to the transition to Jomar but were not budgeted for in 2024.
- $30K increase in legal and other professional and outside services. These costs tend to increase at greater than normal inflation rates.
- The remainder of costs are increasing at inflationary rates.

<u>Interest Expense</u>

FHI is projected to begin drawing on the remainder of the swap loan in 2024. The main benefit of this swap loan will begin on December 31, 2024 when it rolls into the forward fixed term loan. There is a new $5M loan planned for 2025 and has been budgeted with an interest rate of 5%.

<u>Current Income Taxes</u>

Current income taxes are budgeted at $295K, which is an effective tax rate of approximately 12% based on accounting income before taxes. The accelerated CCA will begin to be phased out in 2024.

<u>Net Income and Return on Equity</u>

Net income for 2025 is budgeted to be $2.17M. The ROE calculated on budgeted figures for 2024 is 5.7%. This is below the KPI target of 8%. With the lower dividends paid since 2019 to assist in managing cash flows and capital investment and the increase in rate base, the retained earnings figure has increased at a greater rate than in the past and therefore it will be more difficult to maintain a higher rate of return. FHI will still fall within 300 basis points for OEB ROE targets because OEB ROE is consistently higher than MIFRS ROE and Regulated ROE will be set as part of the COS.

Dividend Payout

Similar to 2024, the dividend payout will be calculated after the completion of the 2024 audited financial statements in April 2025 and will be in accordance with the dividend policy. An estimate of the top up dividend payout has been included in the 5 year commentary. FHI plans to continue to pay bi-annual dividends of $195,165 totaling $390,330.

Cash Flow Statement for 2025

The cash flow statement shows a positive cash position through the end of 2025. Due to capital plans for 2025, FHI is planning to request a $5M SWAP loan when interest rates improve. Long term fixed rate loans are likely to decrease later in 2024.

Loan Covenants

FHI projects to continue to meet its loan covenants in 2025 and has the capacity to borrow more funds if required.

Recommendations:

The 2025 Capital, Operating Budget and Cash Flow statement be accepted as presented.

FESTIVAL HYDRO INC.
2025 CAPITAL BUDGET

	DISTRIBUTION PLANT	BUDGET
Overhead Distribution Projects		**$1,151,750**
VAR	Reinsulating	$ 75,000
D	Highway 83, Dashwood (West End Only)	$ 189,000
SF	Birch St (OH Extension)	$ 116,000
SF	RR Tracks Rebuild - Main and Crombie	$ 62,000
S	Romeo St S - Frederick to Brunswick	$ 312,500
S	Louise St - Brydges to Blake St.	$ 47,500
SF	High St - Huron to Market St.	$ 16,000
SF	Centre St - Ann St to Church St	$ 36,000
S	Nelson St - Walnut St. to Ash St.	$ 69,000
H	Rear Yard Rebuild - Hensall - Brock to Elizabeth St.	$ 73,750
SM	Peel St S - Queen to Elgin - 1PH to 3PH Upgrade	$ 68,000
N/A	Pole Line Design	$ 37,000
N/A	GIS Support	$ 50,000
		$ -
Underground Distribution Projects		**$1,344,850**
SF	Oak/Birch Tie (New Project)	$ 101,200
SF	RR Crossing - Main and Crombie	$ 77,400
SF	Goderich St E Rear-To-Front Conversion	$ 83,100
S	Barron St Townhomes (1989)	$ 91,000
S	Erie St - (60 Erie St. to 100 Erie St.)	$ 29,400
SM	Queen St E/Peel St N UG Tie	$ 54,000
SM	Ingersoll St - East and West Feed to SG	$ 103,400
SM	Maxwell St, White Court, Oakwood Court	$ 243,900
SM	Peel St S - Park to Elgin	$ 267,250
SM	Switchgears - 2 Purchases + Installs	$ 244,200
N/A	GIS Support	$ 50,000
Distribution Transformers		**$ 595,000**
Capital Additions - FHI Driven		**$ 348,965**
Capital Additions - Customer Driven		**$ 356,600**
New/Upgraded Services		**$ 218,140**
Distribution Meters - Residential/Commercial/Industrial Meters		**$ 1,427,297**
	2024 Carry Over	
	Services <50kW	$0
	Services >=50kW	$113,270
	CT's and PT's	$37,880
	SM 2.0 Deployment	$1,276,147
Distribution Automation - SCADA Enhancements		**$ 141,500**
	Smart Fault Indicators - Zurich	$39,800
	M1 Recloser	$72,100
	Misc.	$29,600
Tools & Misc. Equipment		**$ 46,200**
	Tools - Operations	$ 41,200
	Misc Purchases	$ 5,000
Transformer Station		**$ 274,600**
	T1 Metering Unit Replacement	$ 179,600
	TS Facilities	$ 20,000
	TS Capital	$ 75,000
Distribution Station		
	DISTRIBUTION PLANT SUBTOTAL	**$5,904,902**
GENERAL PLANT		**BUDGET**
Lands and Buildings		**$ 505,000**
	Admin Building (Misc)	$ 50,000
	Roof Replacement + Eaves/Soffits - Admin Building	$ 400,000
	Whyte Ave Yard Light Replacements	$ 35,000
	Service Centre (Misc)	$ 20,000
Vehicles and Trailers		**$ 125,000**
	Pickup Truck (Replace Truck 19)	$ 70,000
	Forklift	$ 55,000
Information Technology		
	Software Purchases	**$ 905,000**
	ERP Software Replacement	$ 875,000
	General Software	$ 30,000
	Hardware Purchases	**$ 296,636**
	OT Refresh Phase 1	$ 204,303
	Generic Hardware and Devices	$ 92,333
	GENERAL PLANT SUBTOTAL	**$1,831,636**
	DISTRIBUTION & GENERAL PLANTS TOTAL	**$7,736,538**

To:	Audit Committee
Date:	January 30, 2024
From:	Alyson Conrad, CFO
Re:	Item 12. Five Year Capital Plan, Operating Budgets and Cash Flow Projections - 2025 Through 2029

Included with the 2025 budget statements are the five-year projections for 2026 to 2029. These budgets have been created for years 2026 through 2029 with rates being estimated to increase due to the Cost of Service (COS). The rate increase is subject to change as we progress through the COS Application process in 2024.

Five Year Capital Plan Projections

There is a proposed increase in five-year capital spend in the period from 2025-2029. The total over the 5 years is $36.2 M. Gross Distribution capital spending stays relatively consistent year over year with an average annual spend of $7.2M. This investment level is based on the asset condition assessment completed for the 2025 Cost of Service Application as well as incorporating larger non-typical expenses.

The items that cause an overall increase from typical years include:

- The Asset Condition Assessment (ACA) completed by Kinectrics in preparation for our Cost of Service recommends that we replace approximately 100 poles a year to maintain the overall asset health of our distribution system; up from the 65-70 that we have historically been replacing. A portion of these replacements will be concentrated in Seaforth as this community is converted from 4kV to 27.6kV.

- The Asset Condition Assessment also recommends increased replacement of underground cable every year to maintain the overall health of the distribution system; up from the 2-3 km of cable of historical replacement. These replacement projects have the added benefit of installing the appropriate civil infrastructure to support the underground cable, and add redundant loop feeds in the areas where none currently exists. Distribution transformer spend is affected by this, as underground rebuilds typically include the replacement of the padmount transformers as well. Therefore, as the cable replacement goes up, so do the transformer purchases. It also aligns well with Kinectrics' ACA on the number of transformers recommended to be replaced each year.

- A more aggressive fleet replacement plan of two passenger vehicles each year and one bucket truck on alternating years. This also aligns with Kinectrics' ACA which indicates there are a high number of fleet assets in very poor condition.

- Distribution automation has been increased to allow for the installation of one recloser each year to the system. This will increase the visibility into the distribution system when faults happen. It will also allow for faster fault detection and provide more segmentation during faults to reduce the number of customers impacted.

- Transformer Station (TS) spending has increased by approximately $100,000 each year. 2025 spending is targeted toward replacing the primary metering units (one of which failed in 2023) as like replacements are no longer available. This is being completed to ensure a complete three-phase bus wholesale revenue meter lineup is replaced and engineered to be retrofitted. This avoids reactive work and sourcing replacements should another issue occur leaving half of the TS inoperable, as lead times are significant. The remaining budget is to replace/upgrade electronic components that are nearing end-of-life at 10-15 years of age.

- Capital contributions forecasted for 2025 through 2029, along with customer driven projects forecast for the same period, have increased based on what historic numbers in both categories and where they are expected to remain based on developments that have been communicated to Festival Hydro staff.

- Enterprise Resource Planning (ERP) Implementation – The ERP is planned to be in service in 2025 totaling $1.75M in capital costs, $875K in 2024 and $875K in 2025.

- Smart Meter Redeployment (AMI 2.0) – Included in the distribution capital costs are increases to the smart meter budget. Meters are reaching end-of-life and continue to fail. FHI will begin mass deployment of new metering infrastructure in 2025. The plan is to smooth implementation over 4-5 years to limit stranded assets and to ensure meters are on hand for installation in case of larger scale failures.

Five Year Balance Sheet and Cash Flow Projections

Attached are the five-year balance sheet and cash flow projections.

These 5-year balance sheet and cash flow statements assume limited change to balance sheet items year over year, with the exception of, principal repayments to current debt and new debt planned annually in the forecast period to help fund capital plans. These loans will be secured when rates are more favourable. Covenant requirements are projected to be maintained.

As shown below, we have provided 5-year projections for dividend payments based on the revised policy completed in 2023; however, these dividends are subject to change based on actual results.

Five Year Operating Statement Projection

The following outlines the assumptions used in developing the five-year plan. 2025 has been discussed in detail in the 2025 budget commentary.

Distribution Revenue and Other Operating Revenue

As noted above, distribution revenues are proposed to increase based on results of the Cost of Service Application. In the forecast years, increases are based on estimated inflation amounts plus moderate customer growth. Other operating revenue from 2026 through 2029 have been increased by 1.2% per year to reflect normalized historical increases.

Controllable Costs

Controllable costs for 2026 through 2029 have been projected with detailed labour calculations based on potential retirements and grid movements for all staff. In addition, inflation of 3.5% was used to increase other expenses (unless otherwise known) and known project costs and union costs were added/removed each year as appropriate.

Net Income, ROE and Dividend Payments

Total revenues and expenses are expected to be revised based on settlement and/or OEB approval. Other than a new billing position in 2025 labour and positions are stable through the forecast period. There are increases in depreciation and interest expense due to higher capital acquisitions starting in 2023; remaining higher until completion of the smart meter redeployment.

Return on equity is expected to range between 5% and 7%. FHI's regulatory ROE is higher due to the OEB's deemed cost of capital structure being built into rates, which does not mimic FHI's true capital structure. Therefore, FHI's actual ROE may not align with regulatory ROE.

The dividend policy was updated in 2023. Based on the revised dividend policy, please see the table below for projected dividend amounts. Again, as noted, the dividends are estimates and subject to change based on actual results.

	2025	2026	2027	2028	2029
Forecasted Net Income	2,166,831	1,946,599	1,958,844	1,948,163	2,036,229
Base Dividend	500,000	500,000	500,000	500,000	500,000
25% of Earnings over $1.8M	91,708	36,650	39,711	37,041	59,057
Total Dividend	591,708	536,650	539,711	537,041	559,057

In all years the lending covenants are met based on these projected figures.

Festival Hydro INC.

Attachment 9

1-SEC-6 – Preliminary Scorecard

Scorecard - Festival Hydro Inc.

7/15/2024

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	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		96.99%	95.31%	97.89%	95.92%	93.26%	↓	90.00%	
		Scheduled Appointments Met On Time		98.50%	97.69%	98.88%	97.70%	97.70%	↓	90.00%	
		Telephone Calls Answered On Time		88.45%	98.86%	91.71%	90.42%	96.94%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		99.99	99.93	100	99.99	100			
		Billing Accuracy		99.99%	99.96%	99.98%	99.97%	99.97%	→	98.00%	
		Customer Satisfaction Survey Results		97%	91	91	93	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%	80.00%	77.00%	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	1	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.383	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.79	1.27	1.95	0.81	1.09	↓		1.35
		Average Number of Times that Power to a Customer is Interrupted [2]		1.78	1.00	1.63	0.77	0.81	↓		1.31
	Asset Management	Distribution System Plan Implementation Progress		112	92	105	95	106			
	Cost Control	Efficiency Assessment		3	3	3	3				
		Total Cost per Customer [3]		$650	$629	$614	$674				
		Total Cost per Km of Line [3]		$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	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)		0.53	0.54	0.51	0.46	0.53			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.11	1.04	0.99	0.97	0.99			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	9.30%	9.30%	9.30%			
			Achieved	9.10%	8.89%	9.93%	9.25%	8.62%			

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.

Legend:

5-year trend: ↑ up ↓ down → flat

Current year: target met / target not met

Attachment 10

2-SEC-9 – Copy of Table 2AA & 2AB Update

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-42
Page:	57
Date:	2024-07-25
Net Capital/Gross Capital	Net Capital

Appendix 2-AA
Capital Projects Table

Projects	2015	2016	2017	2018	2019	2020	2021	2022 YTD @ June 30, 2022	2022	2023 YTD @ June 30, 2023	2023	2024 Bridge Year	2024 YTD @ June 30, 2024	2024 Bridge Year (Updated YE Forecast)	2025 Test Year	2025 Test Year (Updated)	2026	2027	2028	2029
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS		MIFRS		MIFRS	MIFRS			MIFRS		MIFRS	MIFRS	MIFRS	MIFRS
System Access																				
Subdivisions	377,707	229,754	118,894	550,809	89,052	455,635	232,456	114,598	222,963	160,091	379,021	369,616	175,101	297,598	406,900	406,900	312,000	334,750	337,800	351,000
New Services	231,003	248,664	471,580	419,148	453,933	335,760	478,141	176,056	410,285	110,780	371,154	300,295	372,880	469,785	375,000	375,000	378,750	371,250	382,500	386,330
Metering	70,980	104,045	104,360	230,484	492,665	207,219	96,889	92,961	362,299	147,648	314,013	200,000	96,882	200,000	112,000	112,000	122,595	127,499	132,599	184,762
AMI 2.0	0	0	0	0	0	0	0	0	0	71,616	96,466	200,000	13,033	200,000	1,316,337	1,316,337	1,540,000	1,585,000	1,631,350	701,830
Other Recoverable Work	33,028	0	38,660	177,542	164,262	87,661	283,622	6,036	17,442	25,636	25,636	142,000	203,265	220,454	189,000	189,000	110,000	113,000	117,000	120,000
System Access Gross Expenditures	712,717	582,463	733,494	1,377,984	1,199,913	1,086,275	1,091,108	389,651	1,012,989	515,771	1,186,291	1,211,911	861,161	1,387,837	2,399,237	2,399,237	2,463,345	2,531,499	2,601,249	1,743,922
System Access Capital Contributions	333,945	206,585	371,810	585,308	443,731	465,828	481,457	162,576	343,410	119,441	446,781	219,113	157,249	335,000	327,188	327,188	331,500	338,130	344,893	351,790
Sub-Total	378,772	375,878	361,684	792,676	756,182	620,447	609,651	227,075	669,579	396,330	739,510	992,798	703,912	1,052,837	2,072,049	2,072,049	2,131,845	2,193,369	2,256,356	1,392,132
System Renewal																				
Animal Mitigation	89,260	39,935	14,565	3,142	80,356	30,343	65,811	78,886	81,197	28,820	65,101	85,000	114,285	114,285	75,000	75,000	75,000	75,000	75,000	75,000
UG Renewal	379,235	280,541	360,585	426,276	422,449	364,501	441,142	51,001	708,274	110,339	541,750	808,898	232,953	808,898	1,188,450	1,188,450	1,231,500	1,534,000	1,602,500	1,614,000
OH Renewal	627,854	571,314	813,336	654,019	623,620	326,703	443,455	328,470	673,465	491,637	873,796	636,999	247,170	676,999	847,750	847,750	1,081,663	1,059,122	1,055,029	1,109,580
Switchgear Replacement	170,280	153,073	136,109	172,642	361,225	224,129	297,367	0	112,104	32,103	41,930	205,800	358,805	378,000	244,200	244,200	244,200	0	0	0
System Re-establishment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	122,000	122,000	90,000	111,000	113,000	115,000
TS Renewal	0	0	0	5,300	35,855	72,697	137,501	7,524	86,263	20,246	212,043	150,000	66,495	150,000	274,600	274,600	272,600	278,632	289,497	298,397
Small Replacements	296,539	386,386	272,113	247,255	222,157	381,714	505,533	142,659	324,643	214,255	379,065	349,164	210,528	349,164	348,965	348,965	355,944	363,063	370,324	377,731
DS Renewal	0	0	0	0	17,481	227,076	1,887	0	0	0	0	0	5,444	5,444	0	0	0	0	0	0
Misc/Other	142,342	-4,053	47,427	56,833	5,260	0	134,657	0	235,832	0	0	0	0	0	0	0	0	0	0	0
System Renewal Gross Expenditures	1,705,511	1,427,197	1,644,134	1,565,466	1,768,402	1,627,164	2,027,352	608,540	2,221,777	897,400	2,113,684	2,235,861	1,235,680	2,482,790	3,100,965	3,100,965	3,350,907	3,420,817	3,505,350	3,589,708
System Renewal Capital Contributions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	1,705,511	1,427,197	1,644,134	1,565,466	1,768,402	1,627,164	2,027,352	608,540	2,221,777	897,400	2,113,684	2,235,861	1,235,680	2,482,790	3,100,965	3,100,965	3,350,907	3,420,817	3,505,350	3,589,708
System Service																				
Voltage Conversion	0	0	0	0	0	0	0		0		0	0	0	0	217,000	217,000	223,510	227,980	234,820	239,816
Distribution Automation	167,466	38,213	29,385	37,782	27,144	50,900	5,689	18,782	33,846	56,385	110,159	76,500	25,103	76,500	141,500	141,500	149,984	155,967	162,205	168,694
Misc/Other	70,200	0	0	0	2,589	0	0		0		0	0			0	0	0	0	0	0
System Service Gross Expenditures	237,666	38,213	29,385	37,782	29,733	50,900	5,689	18,782	33,846	56,385	110,159	76,500	25,103	76,500	358,500	358,500	373,494	383,947	397,025	408,510
System Service Capital Contributions																				
Sub-Total	237,666	38,213	29,385	37,782	29,733	50,900	5,689	18,782	33,846	56,385	110,159	76,500	25,103	76,500	358,500	358,500	373,494	383,947	397,025	408,510
General Plant																				
Fleet	40,680	30,426	7,390	334,227	56,425	0	16,511	0	68,635	81,470	92,935	450,000	9,043	192,000	125,000	370,000	575,000	220,000	477,544	598,230
Tools	15,434	22,344	29,482	35,757	29,367	26,793	26,796	4,811	28,200	19,755	36,453	45,000	8,613	45,000	46,200	46,200	47,436	48,709	50,020	51,371
Building&Equipment	232,893	153,023	136,178	193,352	225,097	156,731	491,840	83,769	365,904	593,941	1,060,506	2,165,000	501,090	2,235,000	505,000	505,000	315,000	535,000	270,000	440,000
IT Hardware	306,328	115,873	93,309	94,549	75,790	60,193	275,020	48,786	176,461	90,594	290,629	193,069	66,171	153,069	296,636	296,636	288,892	366,657	381,323	396,576
IT Software	58,144	233,363	282,383	178,912	226,526	216,420	66,063	247,500	267,546	61,881	446,552	464,598	510,542	927,779	30,000	30,000	72,223	91,664	95,331	99,144
ERP	0	0	0	0	0	0	0		0	0	0	875,000	7,843	551,567	875,000	803,247	0	0	0	0
General Plant Gross Expenditures	653,478	555,029	548,742	836,796	613,205	460,137	876,230	384,866	906,745	847,641	1,927,075	4,192,667	1,103,302	4,104,415	1,877,836	2,051,083	1,298,551	1,262,030	1,274,218	1,585,321
General Plant Capital Contributions																				
Sub-Total	653,478	555,029	548,742	836,796	613,205	460,137	876,230	384,866	906,745	847,641	1,927,075	4,192,667	1,103,302	4,104,415	1,877,836	2,051,083	1,298,551	1,262,030	1,274,218	1,585,321
Miscellaneous																				
Total	**2,975,427**	**2,396,317**	**2,583,945**	**3,232,721**	**3,167,521**	**2,758,649**	**3,518,922**	**1,239,263**	**3,831,948**	**2,197,756**	**4,890,428**	**7,497,827**	**3,067,997**	**7,716,542**	**7,409,350**	**7,582,597**	**7,154,797**	**7,260,163**	**7,432,950**	**6,975,671**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*																				
Total	**2,975,427**	**2,396,317**	**2,583,945**	**3,232,721**	**3,167,521**	**2,758,649**	**3,518,922**	**1,239,263**	**3,831,948**	**2,197,756**	**4,890,428**	**7,497,827**	**3,067,997**	**7,716,542**	**7,409,350**	**7,582,597**	**7,154,797**	**7,260,163**	**7,432,950**	**6,975,671**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table2-41
Page:	56
Date:	2024-04-26
Capital Expnditures = In Service Additions	No

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period:
2025

Historical Period (previous plan[1] & actual)

CATEGORY	2015			2016			2017			2018		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	322	713	121.7%	328	583	77.6%	335	733	119.3%	341	1,378	304.1%
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%
System Service	310	238	-23.3%	314	38	-87.8%	316	29	-90.7%	318	38	-88.1%
General Plant	500	653	30.7%	427	555	30.0%	826	549	-33.6%	445	837	88.0%
TOTAL EXPENDITURE	2,622	3,309	26.2%	2,582	2,603	0.8%	3,016	2,956	-2.0%	2,669	3,818	43.1%
Capital Contributions	120	334	178.3%	120	207	72.2%	120	372	209.8%	120	585	387.8%
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%
System O&M	$ 2,104	$ 2,137	1.6%	$ 2,085	$ 2,102	0.8%	$ 2,124	$ 2,220	4.5%	$ 2,171	$ 2,564	18.1%

CATEGORY	2019			2020			2021		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	348	1,200	245.3%	721	1,086	50.8%	712	1,091	53.2%
System Renewal	1,592	1,768	11.1%	1,935	1,627	-15.9%	1,866	2,027	8.6%
System Service	320	30	-90.7%	55	51	-7.5%	55	6	-89.7%
General Plant	415	613	47.8%	973	460	-52.7%	1,040	876	-15.7%
TOTAL EXPENDITURE	2,675	3,611	35.0%	3,683	3,225	-12.5%	3,673	4,000	8.9%
Capital Contributions	120	444	269.8%	200	466	132.8%	200	481	140.7%
NET CAPITAL EXPENDITURES	2,555	3,168	24.0%	3,483	2,759	-20.8%	3,473	3,519	1.3%
System O&M	$ 2,591	$ 2,368	-8.6%	$ 2,678	$ 2,473	-7.7%	$ 2,642	$ 2,357	-10.8%

CATEGORY	2022				2023			
	Plan	Actual (6 months)	Actual	Var	Plan	Actual (6 months)	Actual	Var
	$ '000			%	$ '000			%
System Access	863	390	1,013	17.4%	805	516	1,186	47.4%
System Renewal	2,044	609	2,222	8.7%	2,469	897	2,114	-14.4%
System Service	55	19	34	-38.5%	75	56	110	46.9%
General Plant	969	385	907	-6.4%	1,665	848	1,927	15.8%
TOTAL EXPENDITURE	3,931	1,402	4,175	6.2%	5,014	2,317	5,337	6.4%
Capital Contributions	200	163	343	71.7%	400	119	447	11.7%
NET CAPITAL EXPENDITURES	3,731	1,239	3,832	2.7%	4,614	2,198	4,891	6.0%
System O&M	$ 2,845	$ 1,456	$ 2,817	-1.0%	$ 3,087	$ 1,644	$ 2,945	-4.6%

CATEGORY	2024				Forecast Period (planned)				
	Plan	Actual (6 months)	Forecast	Var	2025	2026	2027	2028	2029
	$ '000			%	$ '000				
System Access	1,212	861	1,388	-29.0%	2,399	2,463	2,531	2,601	1,743
System Renewal	2,236	1,236	2,483	-44.7%	3,101	3,351	3,421	3,505	3,590
System Service	77	25	77	-67.3%	359	374	384	397	409
General Plant	4,193	1,103	4,104	-73.7%	2,051	1,299	1,262	1,274	1,585
TOTAL EXPENDITURE	7,717	3,225	8,051	-58.2%	7,910	7,487	7,598	7,777	7,327
Capital Contributions	219	157	335	-28.3%	327	332	338	345	352
NET CAPITAL EXPENDITURES	7,517	3,068	7,716	-59.2%	7,583	7,156	7,260	7,432	6,974
System O&M	$ 3,352	$ 1,587	$ 3,352	-52.7%	$ 3,515	$ 3,620	$ 3,729	$ 3,841	$ 3,956

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

3. System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

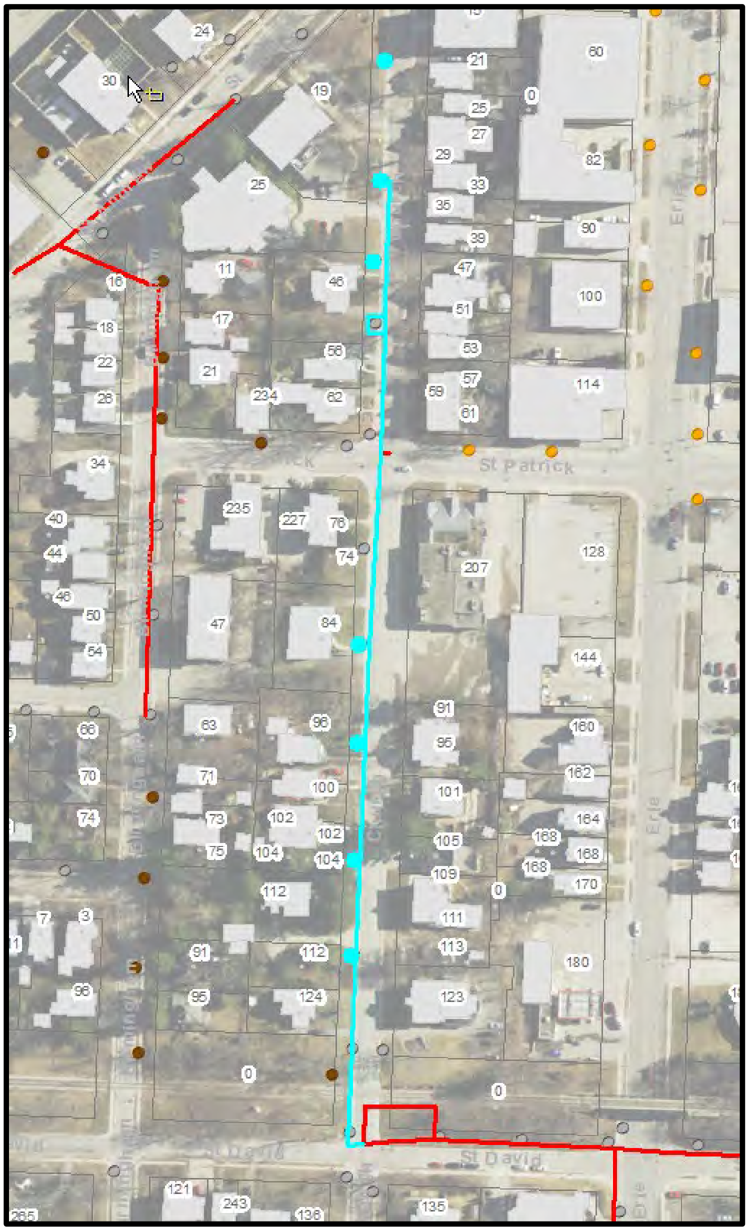
Festival Hydro Inc.

Attachment 11

2-SEC-9 d) – 2020-2024 Budget Documents

2020 Capital

Stratford – Church St (St. David St to Ontario St)



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is an overhead replacement of a primary pole line on Church St, between St. David St and Ontario St. This project will see the replacement of 6 wood poles and 2 concrete poles (new poles to be concrete) with all new primary and neutral conductors. The majority of existing secondary conductor will be transferred onto new poles. The project spans approximately 380 meters. Poles, crossarms, and insulators are between 40 and 50 years old, and are in relatively poor condition. The primary conductor is a non-standard size and has been spliced in a number of locations. There are a number of existing concrete poles along this stretch that will be re-utilized.

The cost of this project is estimated at $109,550.

If this project is not completed, the Stratford M4 feeder will be at risk of future outages due to equipment failure.

This project is expected to start in June 2020 and be in service by end of July 2020.

Stratford – Warwick Rd (Glastonbury Dr to Waddell St)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is an overhead replacement of a primary pole line on Warwick Rd, between Glastonbury Dr and Waddell St. This project will see the replacement of 12 wood poles (new poles to be concrete) with all new primary and neutral conductors. The existing secondary conductor will be transferred onto new poles. The project spans approximately 400 meters. Poles, crossarms, and insulators are between 40 and 50 years old, and are in relatively poor condition. This project was originally planned to be completed as part of a larger project in 2018, but was deferred. This project will also allow us to tie the 8051M1 and 68M5 feeders through the development of a new subdivision on the former fairgrounds site, which is tentatively scheduled to begin in late 2020 or early 2021. The tie between the two circuits will provide additional switching flexibility and allow us to keep scheduled outages shorter on an existing radial circuit in the Glastonbury and Princess area.

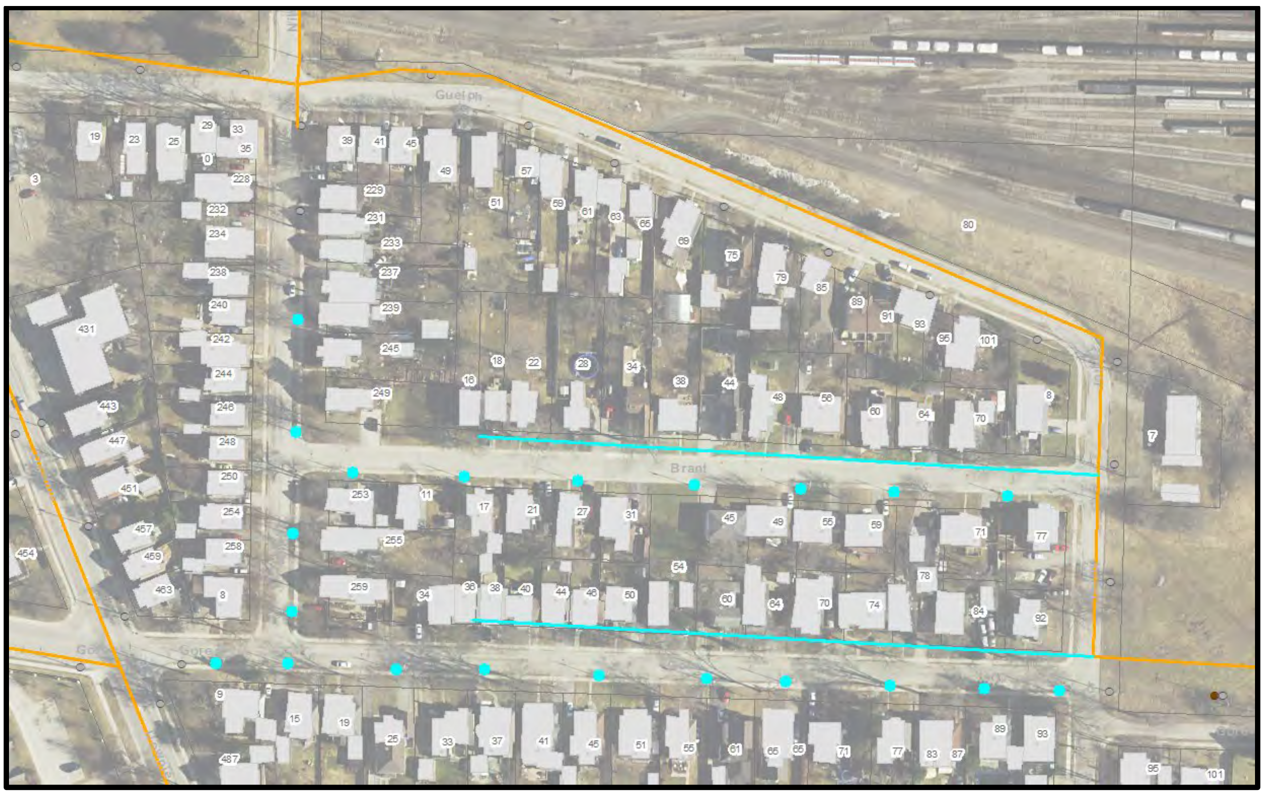
The cost of this project is estimated at $127,700.

This project is expected to start in August 2020 and be in service by end of September 2020.

Stratford – East Gore St, Brant St and Nile St

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is an overhead replacement of primary and secondary pole lines on East Gore St, Brant St and Nile St. This project will see the replacement of 19 wood poles (new poles to be concrete) with all new primary conductors. Approximately 50% of existing secondary conductors will be replaced as well, with the rest to be transferred. The project spans approximately 700 meters. Poles, primary conductors and insulators are between 40 and 50 years old, and are in relatively poor condition. The secondary bus along East Gore St is non-standard open bus construction.



The cost of this project is estimated at $109,700.

This is a continuation of the Guelph St & Taylor St project from 2019.

This project is expected to start in June 2020 and be in service by end of July 2020.

Stratford – Mornington St Recloser Replacement

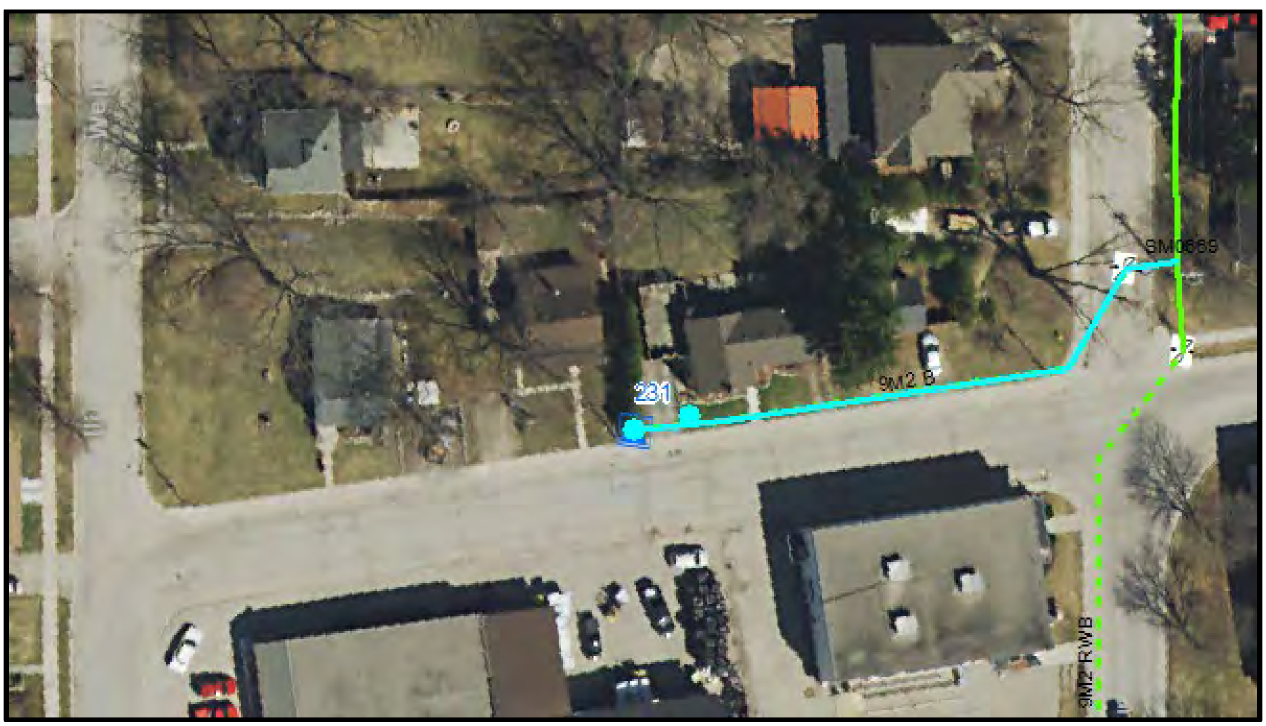
The Mornington St recloser on the 68M5 circuit was taken out of service in the fall of 2019 as it was not operating as expected and it was determined that the recloser's control unit had malfunctioned. This type of recloser is not very common in North America and if a replacement control module is unavailable a replacement recloser would be the best solution.

The cost of this project is estimated to be $43,000.
This project is expected to be completed by end of May 2020.

St. Marys – Station St Overhead Rebuild

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is the replacement of an existing underground primary cable and padmount transformer with an overhead line section. As part of a capital project a number of years ago, it was identified that the existing primary cable could not be removed as the duct has collapsed. The cable itself is approximately 40 years old and it is more practical to rebuild the area using overhead construction. 3 new poles and secondary conductors will be installed along Station St to supply the existing customers from an overhead line on Church St N. Approximately 80m of new secondary conductor is to be installed along with a new overhead transformer.

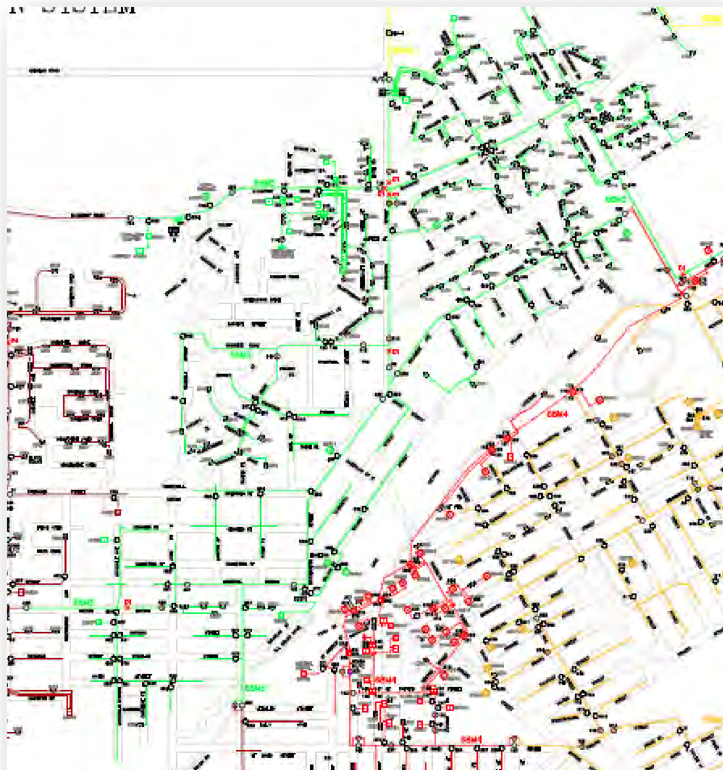


The cost of this project is estimated to be $23,500.
This project is expected to be completed by November 2020.

Stratford – Reinsulate Poles

This project is year 7 of a multi-year project to upgrade the insulators on Stratford feeders, in an attempt to lower then number of momentary outages seen in the City of Stratford. Analysis of the outage causes indicates that animal contacts are the major cause of momentary outages, and further inspection of the feeder suggests the clearance from primary conductor to pole is insufficient to prevent squirrel contacts.

This scope of this project is to install fiberglass extension brackets on the existing insulators and to replace any metallic fasteners as a means of increasing clearances on the poles. The scope of the project will also include the installation of animal guards on or around poles that are difficult to re-insulate. The focus in 2020 will be on the Stratford 68M5 and 8051M1 feeders.



The cost of this project is estimated at $75,000.

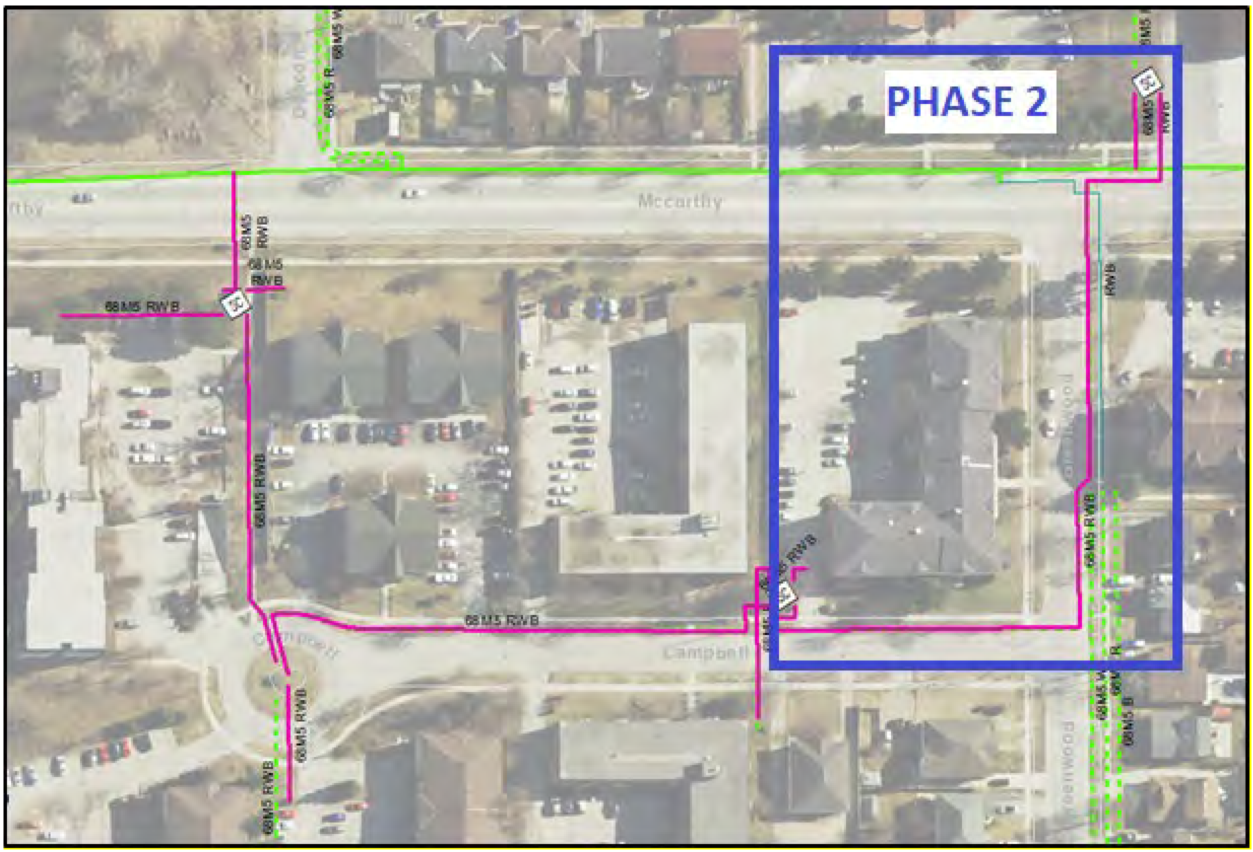
If this project is not completed, the Stratford feeders will be at risk of high outages due to animal contacts.

This project is expected to start in January 2020 and be completed by December 31, 2020.

Stratford – Campbell Court Cable Replacement Phase 2

This project will replace aging infrastructure that has been identified as a potential risk for failure. It is the continuation of Phase 1 of the project, which was completed in 2019.

This section of underground primary distribution cable is reaching its end of life. The cable is 40 years old. Approximately 800m of new TRXLPE 1/0AWG insulated cable will be installed in existing duct to replace the existing cable. The project will also eliminate one padmounted live-front switchgear.



The cost of this project is estimated to be $85,500

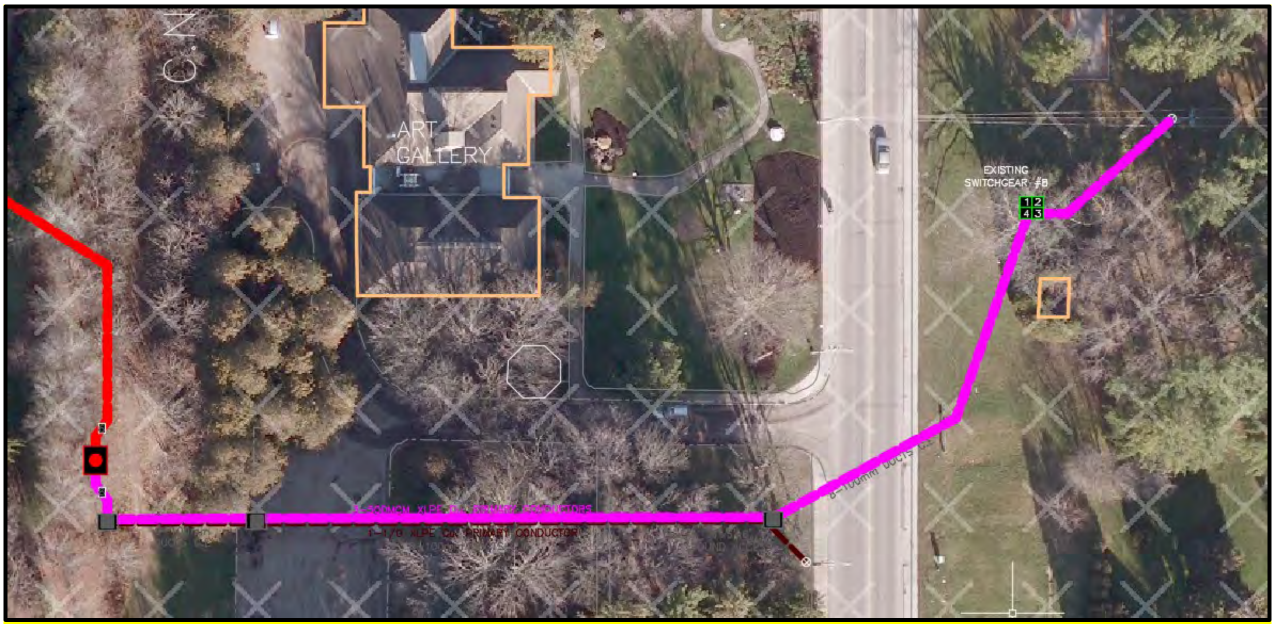
If this project is not completed, customers serviced by the existing infrastructure will be at risk of significant future outages due to equipment failure.

This project is expected to start in May 2020 and to be completed by the end May 2020.

Stratford – M4 Feeder Upgrade – Phase 3

This project will replace aging infrastructure that has been identified as a potential risk for failure.

This section of the Stratford M4 Feeder cable is reaching its end of life. The cable is over 35 years old. Approximately 1800m of new TRXLPE 500MCM feeder cable will be installed in existing duct to replace the existing cable along Lakeside Dr from North St to Cobourg St.



The cost of this project is estimated to be $168,300

If this project is not completed, the Stratford M4 feeder will be at risk of significant future outages due to equipment failure.

This project is expected to start in May 2020 and to be completed by the end of May 2020.

Stratford – Vault Refurbishments

In 2018 FHI commissioned a Consulting Engineer to inspect 47 concrete vault, manhole and pull-pit structures. The scope included a structural assessment which FHI typically completes every 5-6 years. The majority of the structures are in good condition and are experiencing typical deterioration due to age and environmental factors. Recommendations for refurbishments were made for 17 of the structures inspected and budget costs were included for these repairs. FHI plans to complete the recommended repairs over a 3-year period based on the priorities suggested in the report's recommendations. As part of the 2020 budget, 11 separate locations will be refurbished. With the exception of 1 vault, all are in the downtown area.

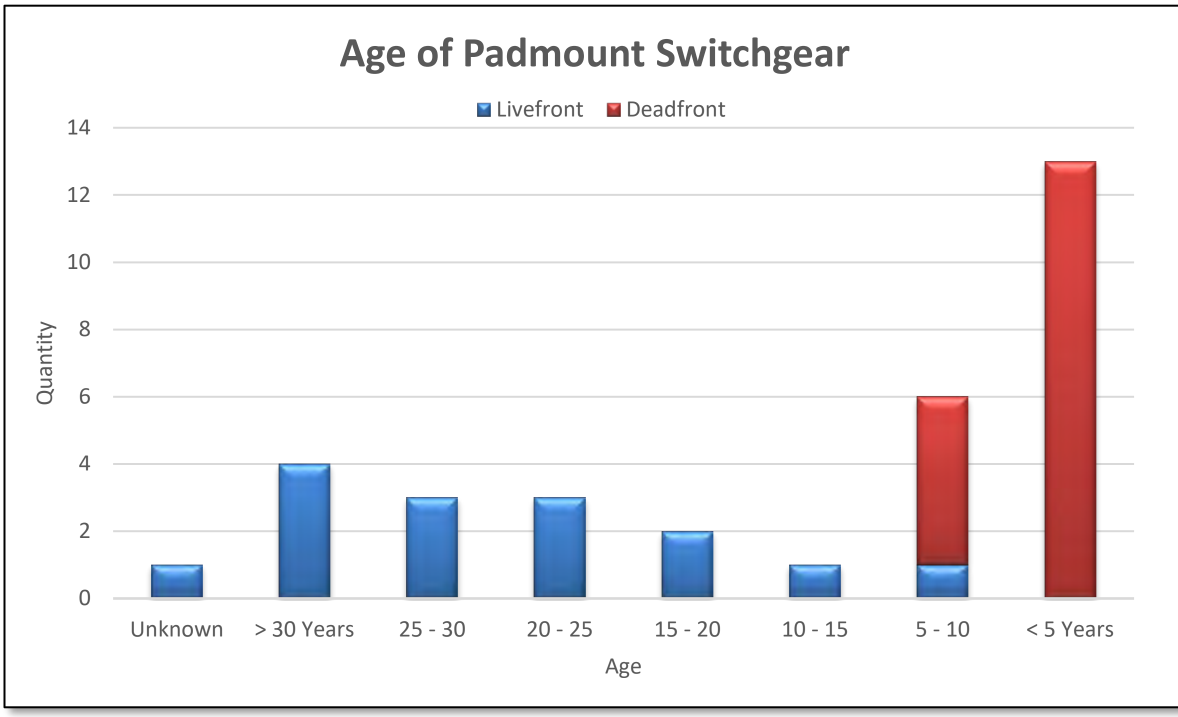
The typical life expectancy for underground vaults is 60 years. In the case of these assets, FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. Vault replacements can be very disruptive to residents and commercial businesses as they are typically located in congested downtown locations in sidewalks and roadways. This approach provides a relatively flat replacement schedule and budget expenditure.

The cost of this project is estimated to be $97,200.

This project is expected to be completed by September 2020.

Stratford – Padmounted Switchgear Replacement 3 units

There were 33 - 25kV padmounted switchgear units in service at FHI at the end of 2019. Before 2012 all padmounted switchgear installations were live front design. These installations had several inherent issues associated with them including: the possibility of animal and vegetation contact and personnel safety. FHI conducts regular inspections of our padmounted switchgear including yearly infrared surveys to identify any potential issues. Several years ago, FHI started a capital program to begin phasing out our live front units in favour of dead front units or through system design changes that make the padmounted switchgear redundant and therefore they are removed from service not replaced.



The typical life expectancy for padmounted switchgear is 30 years. In the case of assets such as transformers FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. This is not the case for switchgear, as the inherent design flaws make it desirable to replace these units as soon as they reach the end of their useful life. To maintain or slightly improve reliability numbers Festival Hydro will increase the number of replacements to 3 in 2020 and then replace between 2 and 4 units moving forward under the new 5 year DSP.

The cost of this project is estimated to be $260,000. As part of the project, an additional switchgear will be eliminated and replaced with an aerial transformer to service the customer that the switchgear currently supplies.

This project is expected to be completed by November 2020.

Transformers

Additional transformers needed due to load growth, replacements, conversions, emergency stock and new developments are expected to cost $187,500. This amount is comparable to previous years and takes historical figures into account. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

Miscellaneous Projects & Capital Additions

Miscellaneous projects are work that is unbudgeted but requires completion in the calendar year including: unsafe infrastructure requiring immediate replacement, cable failures etc. typically found during inspections or unplanned system faults. This budget ID is meant to deal with immediate system issues. A number of poles have been identified as at or near end of life through an annual pole inspection and testing program. Some areas of replacement are identified as follows.

Moderwell St, Stratford is an overhead replacement of a single-phase primary pole line on Moderwell St, west of Monteith Ave. This project will see the replacement of 5 wood poles (new poles to be concrete) with all new primary conductors. The existing secondary conductors will be transferred. The project spans approximately 200 meters. Poles and primary conductors are approximately 50 years old, and are in relatively poor condition as per the pole inspection data from 2019. This project is estimated at a cost $39,500.

Damaged Wood Pole Replacements in Stratford and Seaforth will replace defective infrastructure (poles) that has been identified as a potential risk for failure as part of 2019 wood pole inspections. The scope of this project is an overhead replacement of 12 wood poles in various locations in Stratford and 7 poles in Seaforth. Poles were identified by contractor to be high risk and replaced within approximately a year. The cost of this work is estimated at $123,000

Capital Additions are customer driven work including pole line extensions, transformer installations, subdivision work etc. This budget ID is completely customer driven and both sections are based on historical spending.

The cost of each of Miscellaneous Projects and Capital Additions is $278,000 and $270,000 respectively. These budgets take into account the previous five-year historical average spending.

New and Upgraded Services

Capital costs associated with the connection of new or upgraded residential and commercial secondary services. This section is customer driven and based on historical spending. The cost of this section is estimated at $187,500.

Metering

Capital costs associated with meter replacements and upgrades will be $263,000. This value takes into account historical growth rates and potential meter replacements for residential, commercial and Industrial installations. Also, the first meters purchased as part of the smart meter mass deployment are reaching seal expiry and need to be reverified as per measurement Canada requirements. The remaining 600V, Sentinel 16S meters will also be replaced.

Transformer Station

Capital costs associated with Transformer Station asset replacements and upgrades will be $20,000. Microprocessor based relays and RTU's are approaching end of life and spares will be purchased as lead times, programming and commissioning times may be extensive.

Distribution Stations

Capital costs associated with Distribution Stations will be $320,000. Inspections carried out by Consultants and Contractors in 2019 identified potential issues with Station grounding and bonding. Upgrades to equipment and fence grounding and the station ground grid are needed to maintain safe step and touch potential levels.

Fleet

One vehicle is included in the capital plan for purchase in 2020. A new pickup truck will be purchased to replace Truck 7 (2009) used for Locating and Maintenance. The estimated cost and associated budget is $60,000.

Computer Equipment/Hardware

In order to maintain the health of IT assets through effective lifecycle management and support FHI operations, the planned 2020 budget IT Hardware is $65,600. The budget includes $37,100 used to replace end of life core infrastructure supporting SCADA operations. This will be broken down to include: replacement of Host A and B servers for SCADA, SCADA workstation replacements and SCADA core switches. Also included is the lifecycle management of end user devices (desktops and laptops) and the purchase of new drives for our core hypervisors to support redundancy efforts totaling $18,500.

Tools

Tools and miscellaneous equipment costs will be $30,000. Most of the purchases are for expected replacements of existing tools and equipment as they reach end of life.

Lands and Buildings

The Lands and Buildings budget includes items related to the Administration Building mechanical systems and improvements along with various Service Centre safety & security projects. The Admin building work includes a new rooftop HVAC unit servicing the Customer Service area as it is near end of life along with concrete sidewalk repairs, line painting and furniture at a value of $35,000. Admin building improvements include renovation of the former EMS office space and main floor bathroom renovations for accessibility and functional improvements at a cost of $150,000. Investments for the Service Centre include Security gate upgrades at the Cooper and Wellington entrances, renovations to a bathroom and the Stockkeeper office, CO monitoring and lighting in the truck bays, stock room mezzanine safety upgrades, asphalt repairs and line painting at a cost of $215,000. The total cost is budgeted at $400,000.

Replacement

Replacement projects are selected as part of the asset management plan and distribution system planning process, which look to keep system conditions stable to slightly improving over time. Most budget ID's contain some element of replacement projects, excluding the customer driven sections. Replacement projects represent $2.498 million dollars of the 2019 budget.

Growth Related Work

New and upgraded residential and commercial developments represent approximately $683,000 of the budget. This work is customer driven and the growth rates of the communities in the Festival Hydro service territory in 2020 are expected to be consistent with the 5-year average between 2015 and 2019.

New Technology

Technology spending in 2020 occurs in the areas of IT and SCADA. IT Software is described in three distinct categories as follows:

Cybersecurity - In order to effectively support the cybersecurity agenda and progress towards compliance with the OEB's CSF, we have assigned a total budget of $49,200 to support FHI's efforts. This budget will support several projects which include $6,500 for a vulnerability testing assessment on our OT environment carried out by certified penetration testers at Digital Boundaries. They will also be conducting a full network assessment of both IT and OT operating environments and providing recommendations for hardening the network. We have included $9,000 for real time vulnerability monitoring software and $13,000 for AESI to reassess our risk and support our cybersecurity efforts.

Daffron Software - We have included $45,000 to support regulatory related projects and changes as required by the OEB. As these required updates are not known ahead of time, this allocation has been based on previous spending amounts. The budget also includes $88,700 to support the next phase of CIS conversion to IXP, focused primarily on billing and metering functions. These budget dollars will facilitate the shift in responsibility of most of our Ontario and Festival Hydro programming from our internal IT team to Daffron for support and making information available to the CSR team at the interface touchpoint. This should see a reduction in the current dependence upon custom scripts needed in order to provide analysis and reporting of information from our CIS system. Within the annual budget request of $140,700 is also an allotment of $7,000 to support the implementation of recommendations to work order management and financial management modules of IXP as a result of the value assessment carried out in 2019.

Other software - related budget items include the allocation of $37,500 to support the updating of the FHI portal supporting efforts for customer engagement through capturing their communication preferences and updating the look and feel of our correspondence. This project will also look at revamping the look and feel of the website in a co-project with London Hydro. We have dedicated $20,000 to support our efforts in addressing internal process efficiency, anticipating that this is a multi-year project with year 1 being dedicated to the production of our road map. The remaining $37,000 requested will be used to purchase a number of software products including data centre licences for FHI hypervisors, support for our Linux servers and SCCM support tools.

SCADA projects include updates to smart switches, reclosers and Intellirupters related to the 2019 St. Marys feeder reconfiguration project, SCADA HMI updates related to forecasted multiple customer owned Battery Energy Storage and Behind the Meter Generation installations and various upgrades to SCADA equipment to support new hardware infrastructure installations. The SCADA budget is planned at $55,000 which is based on historical spending and inflation related to materials and services.

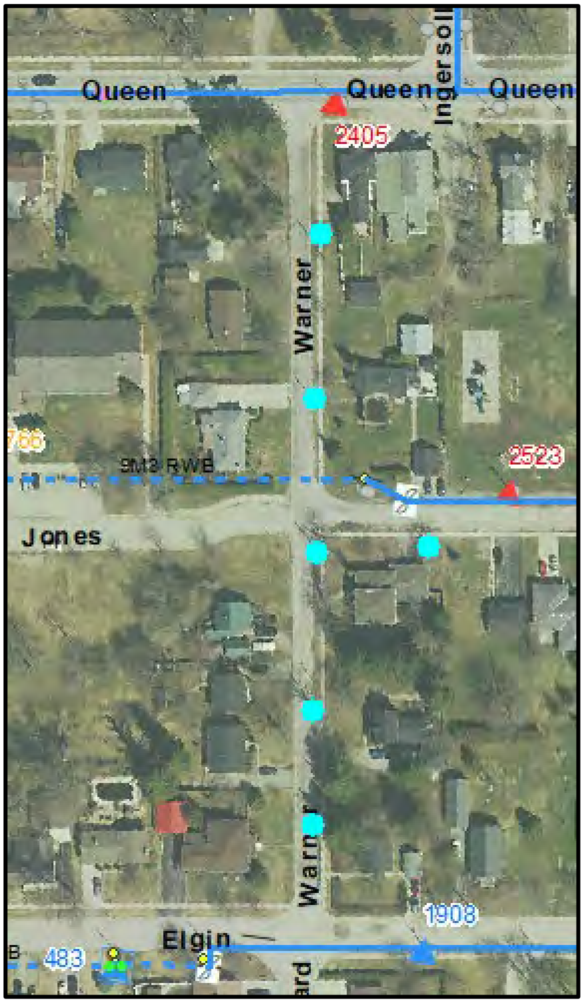
The total cost of these New Technology projects is estimated at $339,400.

FESTIVAL HYDRO INC.
2020 CAPITAL BUDGET

DISTRIBUTION PLANT			2020 BUDGET
Overhead Distribution Projects		**$**	**488,450**
S	Church St - Ontario to St. David	$	109,550
S	Warwick Rd	$	127,700
S	East Gore, Brant, Nile	$	109,700
S	Mornington Recloser (Replacement)	$	43,000
SM	Station St - OH Rebuild	$	23,500
S	Reinsulating	$	75,000
Underground Distribution Projects		**$**	**611,000**
S	Campbell Court Cable replacement - Phase 2	$	85,500
S	68M4 Feeder Upgrade - Phase 3	$	168,300
S	Vault Refurbishments	$	97,200
S	Switchgears - 2 PMH-9, 1 PMH-12, 1 Removal	$	260,000
Distribution Transformers-Purchases only-no labour		**$**	**187,500**
Capital Additions - FHI Driven		**$**	**278,000**
Capital Additions - Customer Driven		**$**	**270,000**
New/Upgraded Services		**$**	**187,500**
Distribution Meters		**$**	**263,000**
Distribution Automation		**$**	**55,000**
	Scada Enhancements	$	-
Tools & Misc. Equipment		**$**	**30,000**
	Tools - Operations	$	25,000
	Misc Purchases	$	5,000
Transformer Station		**$**	**50,000**
	Capacity Upgrade Study (2019 Carryover)	$	30,000
	Microprocessor relays	$	20,000
Distribution Stations		**$**	**320,000**
	Chalk/Welsh St Stations Grounding and Bonding	$	320,000
	DISTRIBUTION PLANT SUBTOTAL		**$2,740,450**
GENERAL PLANT			**2020 BUDGET**
Lands and Buildings		**$**	**400,000**
	Administration Building Various	$	35,000
	Administration Building Improvements	$	150,000
	Service Centre	$	215,000
	Lands	$	-
Vehicles and Trailers		**$**	**135,000**
	Electric Vehicle (Replace Van 15) (2019 Carryover)	$	75,000
	Pickup Truck (Replace Truck 7)	$	60,000
Computer Equipment			
	Software Purchases	**$**	**326,400**
	CIS IXP Customization (2019 Carryover)	$	18,000
	Cybersecurity vulnerability Assessment (2019 Carryover)	$	13,000
	OT Cyber Security (2019 Carryover)	$	11,000
	Cybersecurity	$	49,200
	Daffron Software	$	140,700
	Software Projects	$	94,500
	Hardware Purchases	**$**	**81,200**
	Security Fence (2019 Carryover)	$	5,600
	UPS for Collectors (2019 Carryover)	$	10,000
	Asset Management Hardware	$	65,600
	GENERAL PLANT SUBTOTAL		**$942,600**
	DISTRIBUTION & GENERAL PLANTS TOTAL		**$3,683,050**

2021 Capital

St. Mary's – Warner St (Queen St W to Elgin St W)



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a secondary pole line on Warner St, between Queen St W and Elgin St W. This project will see the replacement of 5 wood poles and elimination of 1 wood pole (new poles to be concrete) with all new secondary conductors. The project spans approximately 200 meters. Poles and secondary conductors are approximately 50 years old and are in relatively poor condition. The secondary bus is an open-bus style, which is very impractical to work with and a potential safety hazard. Apart from these 6 poles, the general area has been rebuilt as part of other recent projects. This specific street was deferred for several years as a result of a Town road reconstruction project, which has now been completed.

The cost of this project is estimated at $29,300.

Deferring this project any further should be avoided due to the condition of the existing infrastructure.

This project is expected to start in April 2021 should only take 1-2 weeks to complete.

St. Mary's – St. Andrew St at Queen St E

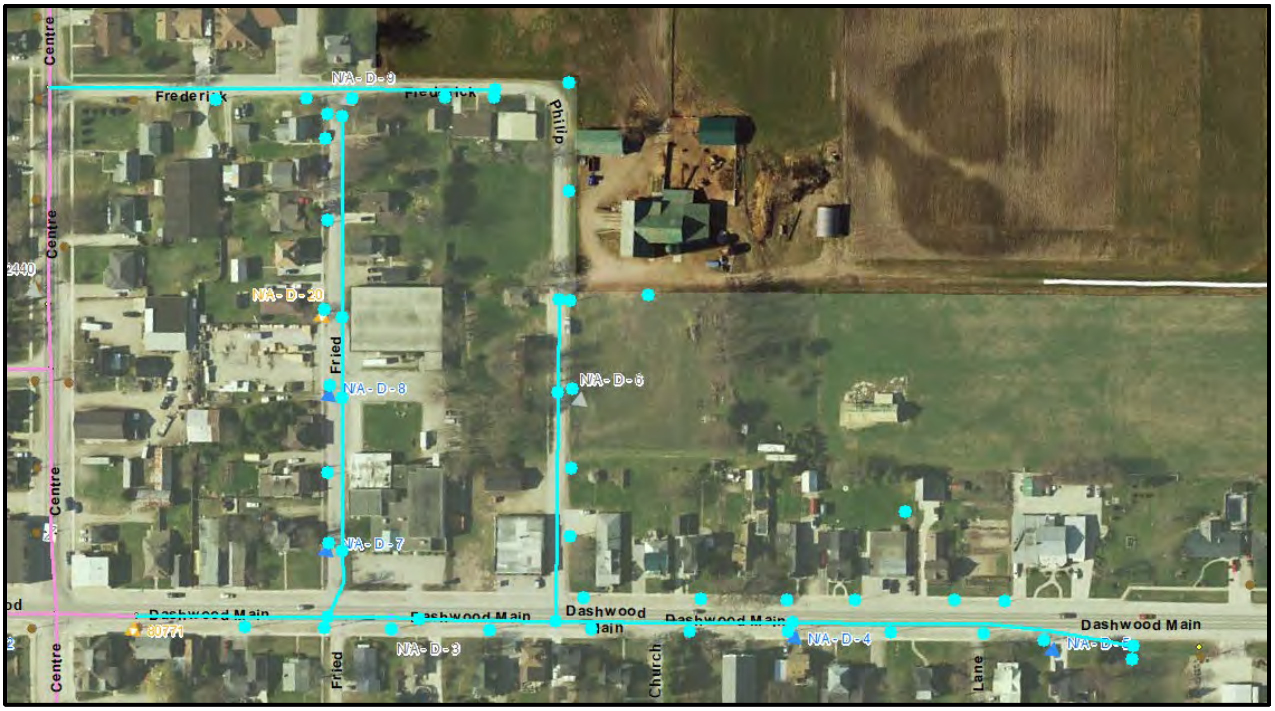
This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a primary pole line on at the intersection of St. Andrew St and Queen St E. This project will see the replacement of 3 wood poles (new poles to be concrete) with a portion of the primary conductor being re-used and one new primary span being installed. The existing secondary conductor will be transferred onto new poles. The project spans approximately 100 meters. 2 of the 3 poles were identified as part of our 2020 pole inspection program as needing replacement within 12 months of testing. The third pole will also be replaced as part of the project to achieve long-term cost savings. All other poles in the area with primary circuits on them have already been replaced with concrete poles.

The cost of this project is estimated at $35,800.

This project is expected to start in mid-April 2021 and be in service by end of April 2021.

Dashwood – Dashwood Main St (East of Centre St), Frederick St, Fried St and Philip St



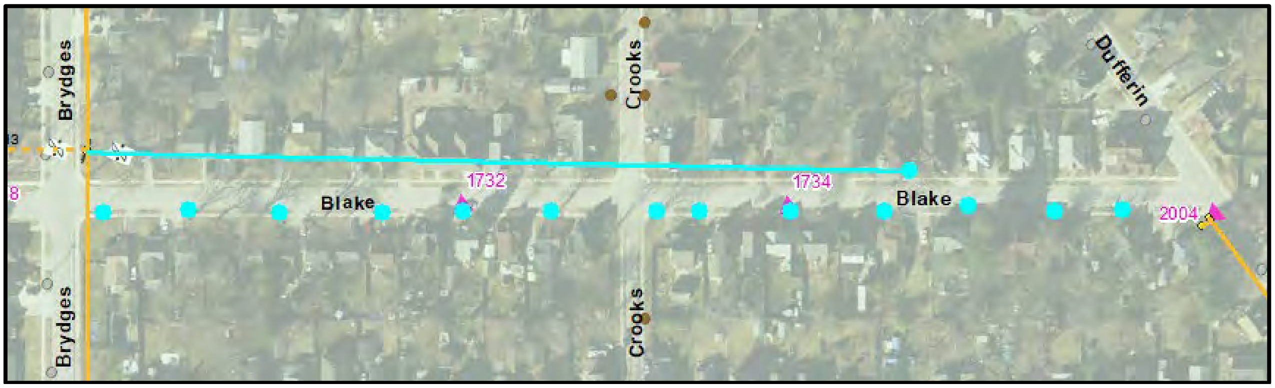
This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of overhead primary and secondary pole lines on Dashwood Main St, Frederick St, Fried St and Philip St. This project will see the replacement of 31 wood poles (new poles to be wood) with all new primary conductors and secondary conductors. The project spans approximately 900 meters. The majority of poles, primary conductors and insulators are between 50 and 60 years old and are in relatively poor condition. As part of the project, at least 4 existing secondary-only poles are planned to be eliminated. The existing 3 phase circuit east of Philip St will also be reduced to a single phase circuit, as there is no current or forecasted need for 3 phase power on the far east end of the town. The new poles however will be framed such that a 3 phase upgrade is relatively easily done, should there ever be a need for it.

The cost of this project is estimated at $186,300.

This project is expected to start in May 2021 and be in service by mid-July 2021.

Stratford – Blake St (Brydges St to Dufferin St)



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of an overhead primary and secondary pole line on Blake St between Brydges St and Dufferin St. This project will see the replacement of 13 wood poles (new poles to be concrete) with all new primary conductors. Existing lashed secondary bus is to be transferred onto new poles. The project spans approximately 370 meters. The majority of poles, primary conductors and insulators are between 50 and 55 years old and are in relatively poor condition based on pole inspection results.

The cost of this project is estimated at $109,300 and is expected to start in May 2021 with an expected completion date of early June 2021.

Stratford – Queensland Rd (between Freeland Dr and John St)

The scope of this project is the extension of an overhead primary circuit on Queensland Rd to facilitate the removal of an existing air-insulated switchgear. The project will span approximately 60 meters and will utilize existing concrete poles. New primary conductors, hardware and an aerial transformer will be installed to re-route a 3 phase service for a school.

The cost of this project is estimated at $16,800.

It is anticipated that this project will be completed in the summer of 2021.

Stratford – Burritt St (Douro St to Frederick St)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of an overhead primary pole line on Burritt St between Douro St and Frederick St. 5 wood poles are to be replaced as part of this project (new poles to be concrete). The existing primary conductors will be transferred as they are in relatively good condition. This is one of a few remaining pole lines in Stratford with porcelain insulators for the primary circuits and a few of the poles were identified as having low remaining life. Apart from these 5 poles, everything else in the general area has already been rebuilt. This pole line is on the 68M8 circuit in Stratford, which supplies some of Stratford's most critical commercial and industrial load. By upgrading this last remaining section of the circuit in this area, the risk of disruption due to failed equipment will be reduced significantly.

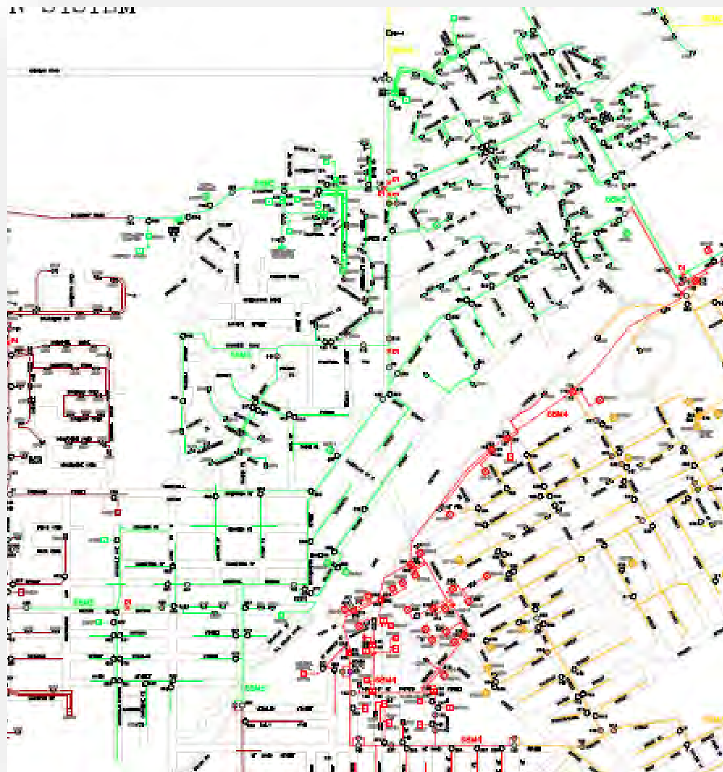
The cost of this project is estimated at $53,200.

It is anticipated that this project will be completed in the fall of 2021.

Stratford – Reinsulate Poles

This project is year 8 of a multi-year project to upgrade the insulators on Stratford feeders, in an attempt to lower then number of momentary outages seen in the City of Stratford. Analysis of the outage causes indicates that animal contacts are the major cause of momentary outages, and further inspection of the feeder suggests the clearance from primary conductor to pole is insufficient to prevent squirrel contacts.

This scope of this project is to install fiberglass extension brackets on the existing insulators and to replace any metallic fasteners as a means of increasing clearances on the poles. The scope of the project will also include the installation of animal guards on or around poles that are difficult to re-insulate. The focus in 2021 will be on the Stratford 68M5 and 8051M1 feeders.



The cost of this project is estimated at $75,000.

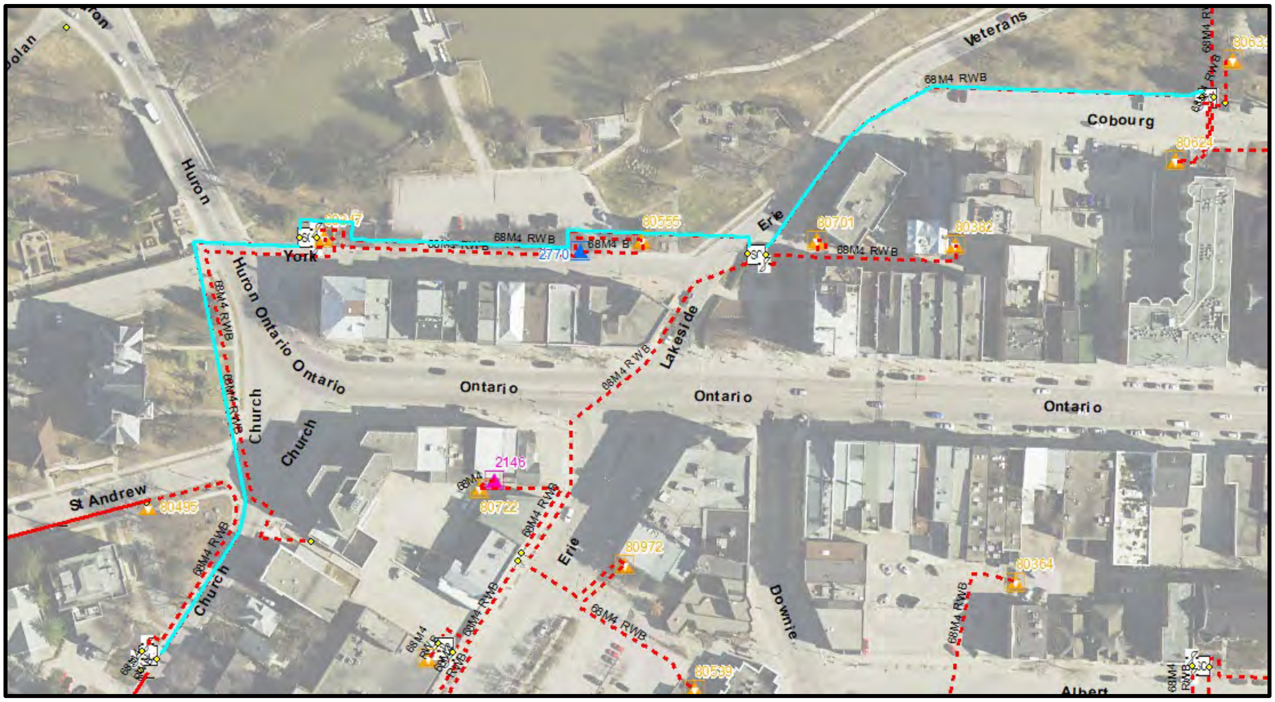
If this project is not completed, the Stratford feeders will be at risk of high outages due to animal contacts.

This project is expected to start in January 2021 and be completed by December 31, 2021.

Stratford – M4 Feeder Upgrade – Phase 4

This project will replace aging infrastructure that has been identified as a potential risk for failure.

This section of the Stratford M4 Feeder cable is reaching its end of life. The cable is over 35 years old. Approximately 1900m of new TRXLPE 500MCM feeder cable will be installed in existing duct to replace the existing cable along Cobourg St, Erie St, York St, Huron St and Church St.



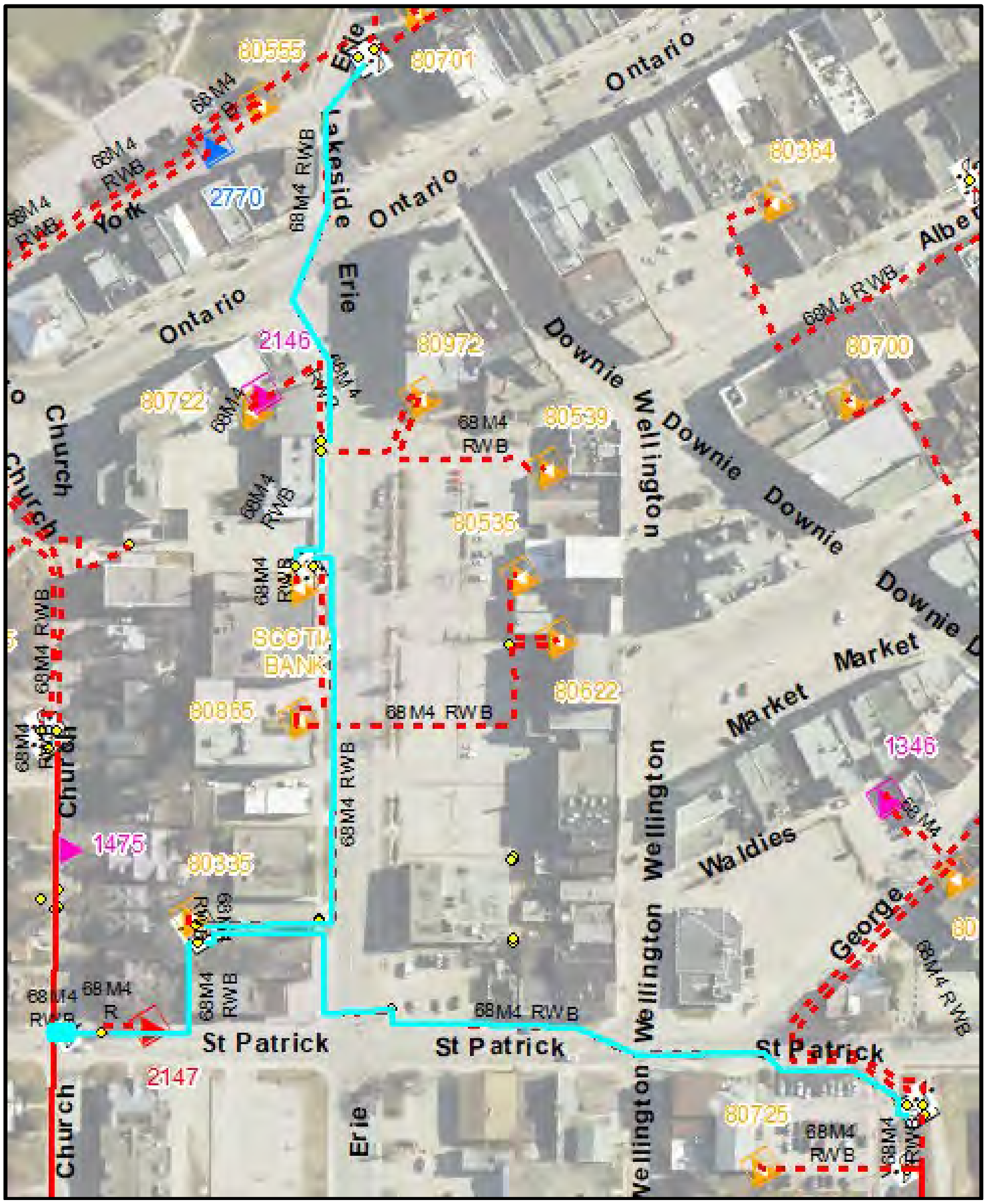
The cost of this project is estimated to be $202,000

If this project is not completed, the Stratford M4 feeder will be at risk of significant future outages due to equipment failure.

This project is expected to start in July 2021 and to be completed by the end of July 2021.

Stratford – Erie St & St. Patrick St Cable Replacement

This project will replace aging infrastructure that has been identified as a potential risk for failure.



This section of underground primary distribution cable is reaching its end of life. The cable is over 35 years old and services a significant number of commercial and residential customers in the downtown core. Approximately 1000m of new TRXLPE 1/0AWG insulated cable will be installed in existing duct to replace the existing cable. This will be Phase 1 of a 2-year project. The overall goal will be to eliminate an additional switchgear and reconfigure the existing primary circuits to allow more long-term operating flexibility.

The cost of this project is estimated to be approximately $100,000 and will be completed in the summer of 2021.

Stratford – Church St & St. Andrew St Cable Replacement

This project will replace aging infrastructure that has been identified as a potential risk for failure.

This section of underground primary distribution cable is reaching its end of life. The cable is over 35 years old and services a small number of critical customers with no options of back-feeding them in case of a cable failure. Approximately 400m of new TRXLPE 1/0AWG insulated cable will be installed in existing duct to replace the existing cable. This project will be completed in conjunction with the 68M4 – Phase 4 project and will result in the elimination of an additional switchgear in front of the Library.

The cost of this project is estimated to be approximately $29,200 and will be completed in the summer of 2021.

Stratford – Vault Refurbishments

In 2018 FHI commissioned a Consulting Engineer to inspect 47 concrete vault, manhole and pull-pit structures. The scope included a structural assessment which FHI typically completes every 5-6 years. Most of the structures are in good condition and are experiencing typical deterioration due to age and environmental factors. Recommendations for refurbishments were made for 17 of the structures inspected and budget costs were included for these repairs. 14 of the structures were fully refurbished as part of the 2019 and 2020 capital budgets. As part of the 2021 budget, the remaining 3 locations will be refurbished, at 2 of those locations a roof slab replacement is required.

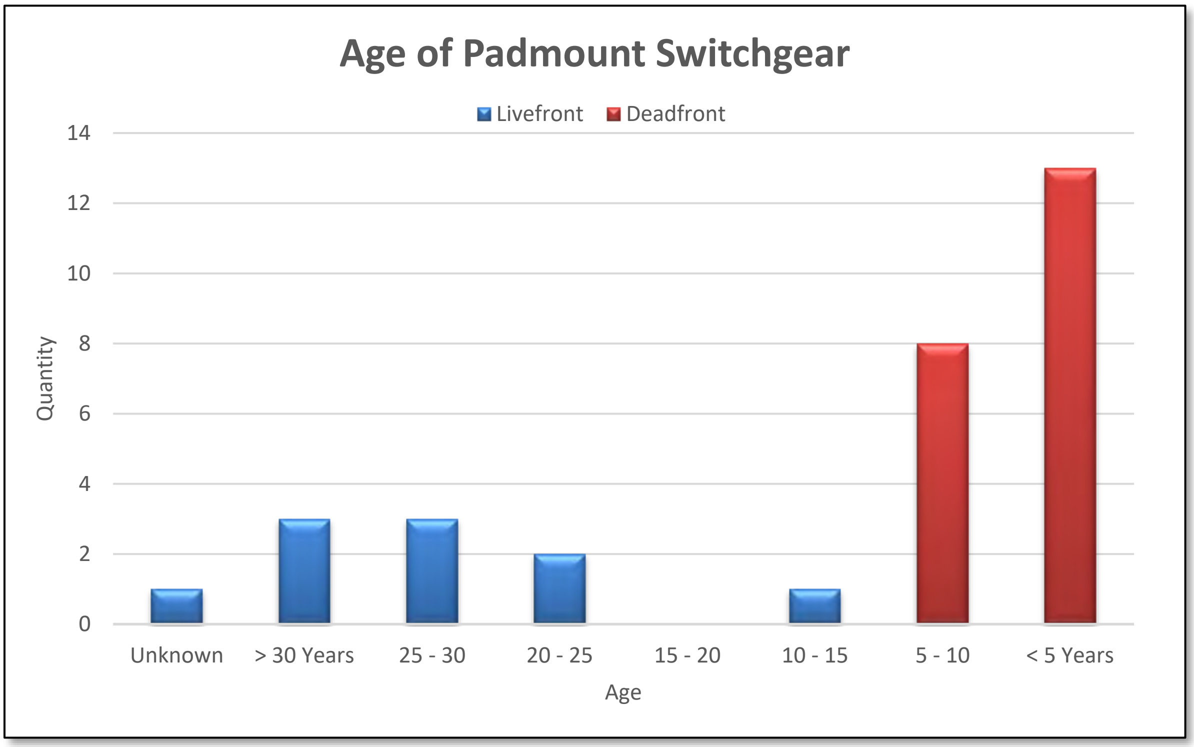
The typical life expectancy for underground vaults is 60 years. In the case of these assets, FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. Vault replacements can be very disruptive to residents and commercial businesses as they are typically located in congested downtown locations in sidewalks and roadways. This approach provides a relatively flat replacement schedule and budget expenditure.

The cost of this project is estimated to be $73,000.

This project is expected to be completed by September 2021.

Stratford – Padmounted Switchgear Replacement - 2 Units To Be Replaced, 4 Units To Be Eliminated

By the end of 2020, there are expected to be 10 - 25kV livefront, padmounted switchgear units in service in Stratford. Before 2012 all padmounted switchgear installations were live front design. These installations had several inherent issues associated with them including: the possibility of animal and vegetation contact and personnel safety. FHI conducts regular inspections of our padmounted switchgear including yearly infrared surveys to identify any potential issues. Several years ago, FHI started a capital program to begin phasing out our live front units in favour of dead front units or through system design changes that make the padmounted switchgear redundant and therefore they are removed from service not replaced.



The typical life expectancy for padmounted switchgear is 30 years. In the case of assets such as transformers FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. This is not the case for switchgear, as the inherent design flaws make it desirable to replace these units as soon as they reach the end of their useful life. As part of the 2021 budget the plan is to replace 2 switchgears and eliminate 4 by reconfiguring the primary circuits that the switchgears are currently connected to.

The cost of this project is estimated to be $237,800.

This project is expected to be completed by November 2021.

Transformers

Additional transformers needed due to load growth, replacements, conversions, emergency stock and new developments are expected to cost $191,250. This amount is comparable to previous years and takes historical figures into account. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

Miscellaneous Projects & Capital Additions

Miscellaneous projects are work that is unbudgeted but requires completion in the calendar year including: unsafe infrastructure requiring immediate replacement, cable failures etc. typically found during inspections or unplanned system faults. This budget ID is meant to deal with immediate system issues. A number of poles have been identified as at or near end of life through an annual pole inspection and testing program. Some areas of replacement are identified as follows.

Damaged Wood Pole Replacements in Stratford will replace the remaining 6 defective poles that were identified as a potential risk for failure as part of 2019 wood pole inspections. In addition to those replacements, approximately 15 additional poles will be replaced in the remaining communities as a result of 2020 inspections. The cost of this work is estimated at $94,700.

Capital Additions are customer driven work including pole line extensions, transformer installations, subdivision work etc. This budget ID is completely customer driven and both sections are based on historical spending.

The cost of each of Miscellaneous Projects and Capital Additions is $283,560 and $275,400 respectively. These budgets take into account the previous five-year historical average spending.

New and Upgraded Services

Capital costs associated with the connection of new or upgraded residential and commercial secondary services. This section is customer driven and based on historical spending. The cost of this section is estimated at $191,250.

Metering

Capital costs associated with meter replacements and upgrades will be $245,545. This value takes into account historical growth rates and potential meter replacements for residential, commercial and Industrial installations. With a number of residential developments under construction, it is expected a portion of the budget will be spent on new residential meters. Investments will also be made into primary metering equipment as well as LTE/ethernet based interval meters to support MIST project and reverification of phone-line interval meters which may be reaching end of life.

Transformer Station

Capital costs associated with Transformer Station asset replacements and upgrades will be $161,460. Microprocessor based relays and RTU's are approaching end of life and spares will be purchased as lead times, programming and commissioning times may be extensive.

Distribution Stations

No capital work is planned for the Distribution Stations in Seaforth in 2021.

Fleet

One vehicle is included in the capital plan for purchase in 2021. A new pickup truck will be purchased to replace Truck 7 (2009) used for Locating and Maintenance. The estimated cost and associated budget is $60,000.

Computer Equipment/Hardware

In order to maintain lifecycle management of IT assess to effectively support business operations, the planned IT Hardware budget amounts to $257,834. As our IBM server (hosting all of our core business applications through Daffron) is 7 years old, it is necessary to replace it in 2020 at a cost of $205,834. This cost includes new servers for both the production ($134,834) and HA ($66,000) environments. We met with our IBM reseller to review all possible replacement options whilst maintaining surety of business operations, such as repurposing our current production server as the HA backup, however when we evaluated each of the options provided, procuring a smaller HA server was the best economic solution. We have also included $25,500 to purchase a SAN which will allow for more efficient management of our resources, and facilitates the implementation of a robust back-up strategy to support DR planning.

We have implemented a 4-year replacement strategy for user devices (warranty period + 1 year) and have included 14 device replacements the 2020 budget, totalling $21,500 which will maintain our current replacement schedule.

We have also included a $5,000 budget allocation for hardware not budgeted for and purchased on an 'as needs' basis – such as the replacement of monitor's, computer peripherals or other unplanned purchases.

Tools

Tools and miscellaneous equipment costs will be $30,000. Most of the purchases are for expected replacements of existing tools and equipment as they reach end of life.

Lands and Buildings

The Lands and Buildings budget includes several 2020 carry-over items related to the Administration Building mechanical systems and improvements along with various Service Centre safety & security projects. The Admin building work includes a new rooftop HVAC unit servicing the Customer Service area as it is near end of life along with concrete sidewalk repairs and line painting at a value of $38,500. Service Centre carry-over projects include Security gate upgrades at the Cooper and Wellington entrances, HVAC installation and renovations to the Stockkeeper office, CO monitoring in the mechanics bay, and asphalt repairs and line painting at a cost of $148,689.

Admin building improvements include renovations to the first and second floor bathrooms for replacement of failing pipework along with accessibility and functional improvements at a cost of $210,000. Other 2021 Admin building projects include building code upgrades to the rooftop guarding related to the HVAC replacement, Chubb Security hardware replacements as the current system will no longer be supported at the end of 2021, Rhyzome area ductwork, security cameras, COVID plexiglass barriers and furniture at a cost of $136,100.

2021 Investments for the Service Centre and other facilities include replacement of a failed septic system with a municipal drain connection at MS8, IT Server building interior security fence for server racking, service center exterior door replacement, employee ID card printer, updated designated substance reporting and overall facilities contingency at a cost of $55,100.

The total Lands and Buildings budget for 2021 is $588,389.

Replacement

Replacement projects are selected as part of the asset management plan and distribution system planning process, which look to keep system conditions stable to slightly improving over time. Most budget ID's contain some element of replacement projects, excluding the customer driven sections. Replacement projects represent $2.829 million dollars of the 2021 budget.

Growth Related Work

New and upgraded residential and commercial developments represent approximately $685,048 of the budget. This work is customer driven and the growth rates of the communities in the Festival Hydro service territory in 2021 are expected to be consistent with the 5-year average between 2015 and 2019.

New Technology

Technology spending in 2021 occurs in the areas of IT and SCADA. Within this budget is a proposed software spending of $103,500 broken down into the below groups:

Daffron software – based on historical spending patterns supporting custom programming changes to support OEB mandated regulations, we have requested $45,000 to support any item falling into this category. We have also included a total of $25,000 to support our CIS conversion project with phase 1 of the IXP update being delivered in February 2021 and subsequent modules within phase 2 being delivered throughout 2021.

Festival Hydro Website update – We currently host our Festival Hydro website through London Hydro and have contracted with them to update our current website management platform. Whilst some discussions and preliminary design has been undertaken in 2020, we expect to go live with our new platform in Q2 of 2021 and have allocated the remaining cost of this project ($12,000) to the budget request.

Cyber Security – we have requested $16,500 to contract Digital Boundaries to reassess our network in 2021, following the initial assessments carried out in 2020. Normally, we would anticipate large assessments such as this to take place bi-annually (with a 3rd party risk assessment on alternate years), however – as we are planning significant change regarding IT operations in 2021 feel it's prudent to conduct a follow up in 2021.

Temagami - $5,000 is requested to complete the configuration of the Vendor Information System, initiated in 2020 and is required to meet MOL standards and mitigate third party risks.

SCADA projects include projects involving hardware replacements and upgrades, SCADA HMI updates related to forecasted multiple customer owned Battery Energy Storage and Behind the Meter Generation installations and various upgrades to SCADA routers and switches to support new hardware infrastructure installations related to Cyber Security Operational Technology (OT). The SCADA budget is planned at $55,000 which is based on historical spending and inflation related to materials and services.

The total cost of these New Technology projects is estimated at $158,500.

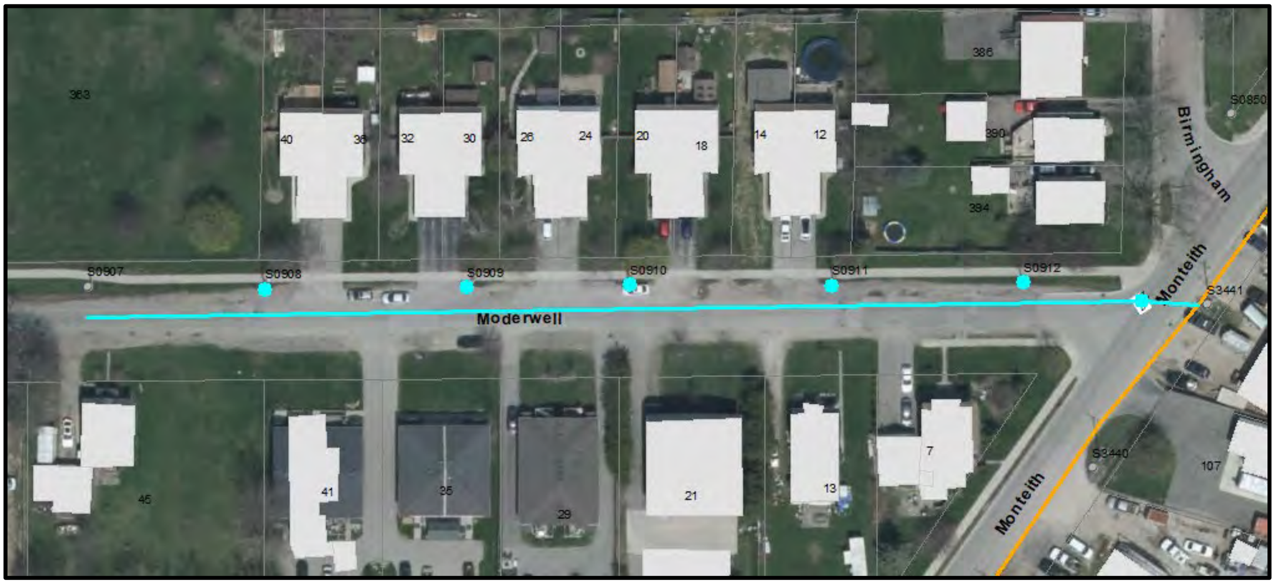
It should be noted that in regards to the IT Roadmap, a total of $30,000 has been added to the 2021 capital budget above to support 2 activities included in the Roadmap action plan which include supporting the finalization of implementing a vendor information management system (Required to meet MOL standards and mitigate third party risks) and the procurement of a SAN (needed to redesign IT backup strategy for DR purposes). These projects don't necessarily move the organization forward or improve productivity and don't represent any significant investment in doing so. Constraints on available cash for capital spending and internal resourcing are the primary drivers for this approach.

FESTIVAL HYDRO INC.
2021 CAPITAL BUDGET

DISTRIBUTION PLANT		2021 BUDGET
Overhead Distribution Projects		**$ 575,700**
	2020 Carryover	$ 70,000
	Warner St - OH Rebuild	$ 29,300
	St. Andrew St - At Queen St E	$ 35,800
	Dashwood - Fried St & Frederick St	$ 186,300
	Blake St - Dufferin to Burritt St	$ 109,300
	Burritt St - Douro St to Frederick St	$ 53,200
	Queensland Rd - OH Line Extension for SG Replacement	$ 16,800
	Reinsulating	$ 75,000
Underground Distribution Projects		**$ 654,000**
	2020 Carryover	$ 12,000
	68M4 Feeder Upgrade - Phase 4	$ 202,000
	68M4 Feeder Upgrade - St. Andrew St Feed	$ 29,200
	Erie St & St Patrick St - UG Cable Replacement	$ 100,000
	Switchgears - 2 PMH-9, 1 PMH-12, 4 Removal	$ 237,800
	Vault Refurbishments - MH40, MH42, RBC	$ 73,000
Distribution Transformers-Purchases only-no labour		**$ 191,250**
Capital Additions - FHI Driven		**$ 283,560**
Capital Additions - Customer Driven		**$ 275,400**
New/Upgraded Services		**$ 191,250**
Distribution Meters		**$ 245,545**
Distribution Automation		**$ 55,000**
	Scada Enhancements	$ 55,000
Tools & Misc. Equipment		**$ 30,000**
	Tools - Operations	$ 25,000
	Misc Purchases	$ 5,000
Transformer Station		**$ 161,460**
	TS Capital (T1 Relays and RTU's)	$ 161,460
	DISTRIBUTION PLANT SUBTOTAL	**$2,663,165**
GENERAL PLANT		**2021 BUDGET**
Lands and Buildings		**$ 588,389**
	2020 Carryover Admin (RTU Cust Serv, Parking Lot paitning/repairs)	$ 38,500
	2020 Carryover Service Centre Various	$ 148,689
	2020 Carryover Administration Building Improvements	$ 210,000
	Administration Building Various	$ 136,100
	Administration Building Improvements	$ -
	Service Centre	$ 55,100
	Lands	$ -
Vehicles and Trailers		**$ 60,000**
	Pickup Truck (Replace Truck 7) (2020 Carryover)	$ 60,000
Computer Equipment		
	Software Purchases	**$ 103,500**
	CIS Projects	$ 70,000
	Website and Customer Software	$ 17,000
	Cyber Security	$ 16,500
	Hardware Purchases	**$ 257,834**
	IBM Server	$ 205,834
	Generic Hardware and Devices	$ 52,000
	GENERAL PLANT SUBTOTAL	**$1,009,723**
	DISTRIBUTION & GENERAL PLANTS TOTAL	**$3,672,888**

<u>2022 Capital</u>

Stratford – Moderwell St (West of Monteith Ave)



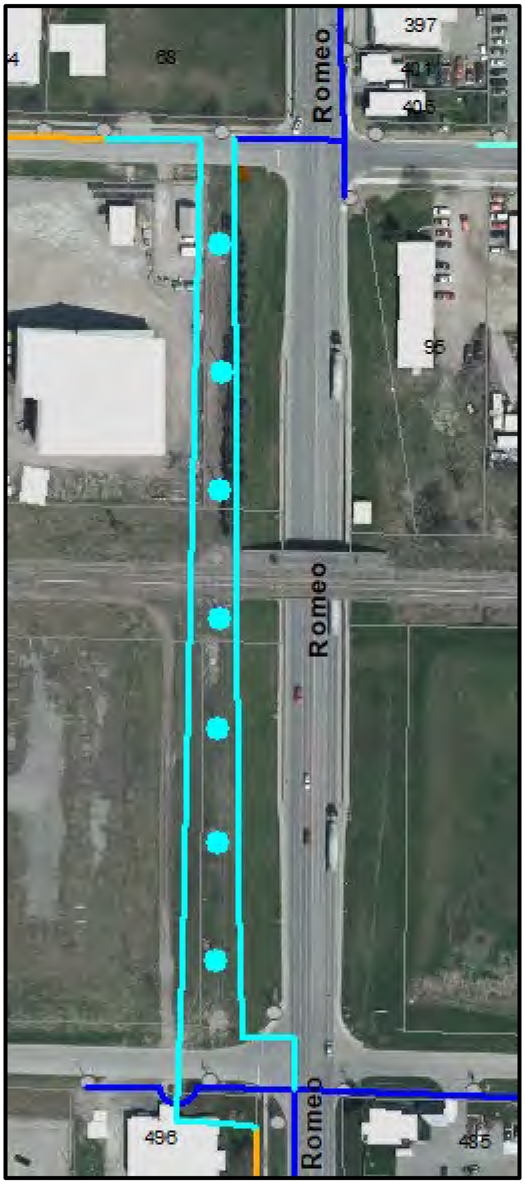
This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a single-phase primary & secondary pole line on Moderwell St, west of Monteith Ave. This project will see the replacement of 5 wood poles (new poles to be concrete) with new primary conductors. The project spans approximately 200 meters. Poles and primary conductors are over 50 years old and are in relatively poor condition based on pole inspection results. Apart from these poles, the general area has been rebuilt as part of other recent projects.

The cost of this project is estimated at $43,500.

This project is expected to start in April 2022 should only take 2-3 weeks to complete.

Stratford – Romeo St S (Frederick St to Park St)



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a primary pole line on Romeo St S between Frederick St and Park St. This project will see the replacement of 6 wood poles and 1 concrete pole (new poles to be wood as they are not readily accessible from the roadway). This pole line carries 2 primary circuits, the 68M2 and 68M3. The primary conductors for the 68M2 circuit will be replaced, while the primary conductors for the 68M3 circuit will be transferred. The project spans approximately 300 meters. The poles are in poor condition and present a potential hazard as both circuits cross active railroad tracks. All other poles in the area with primary circuits on them have already been replaced.

The cost of this project is estimated at $104,000.

This project is expected to start in mid-June and should be completed in mid-July.

Stratford – Glastonbury Dr (Warwick Rd to Brett St)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of 3 wood poles (new poles to be concrete) along Glastonbury Dr between Warwick Rd and Brett St. The project spans approximately 100 meters. Primary and secondary conductors are to be transferred as part of this project. The majority of poles, primary conductors and insulators over 50 years old and are in relatively poor condition. As part of the Warwick Rd rebuild in 2021, crews identified that these poles were in very poor shape near the top of the poles and as a result of that the rebuild of this section was moved up to 2022.

The cost of this project is estimated at $39,200.

This project is expected to start in August and be in completed in approximately 2 weeks.

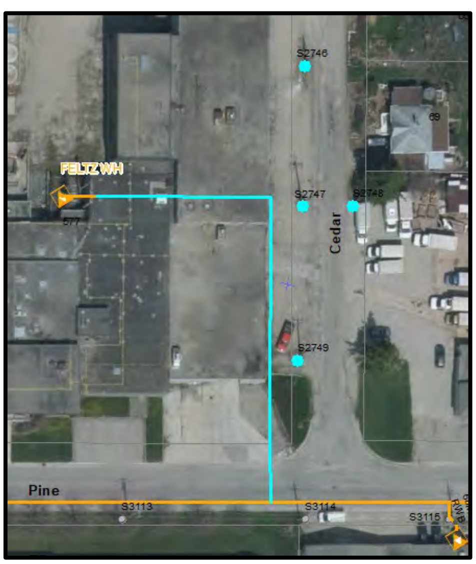
Stratford – West Gore St (Erie St to Wellington St)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of an overhead primary pole line on West Gore St between Erie St and Wellington St. This project will see the replacement of 3 wood poles (new poles to be concrete) while the primary conductors will be transferred. The project spans approximately 120 meters. The poles are approximately 50 years old and are in relatively poor condition. The primary conductors are also supported by wooden crossarms and porcelain insulators, which have a higher risk of failure.

The cost of this project is estimated at $37,600 and is expected to start in late fall and should take approximately 2 weeks to complete.

Stratford – Cedar St (North of Pine St)



The scope of this project is the replacement of 4 wood poles (new poles to be concrete) and overhead primary conductor on Cedar St. The poles are in poor condition and the primary conductors are supported by wooden crossarms and porcelain insulators. The primary conductors also cross an industrial facility and upgrading the supporting structures will reduce the risk of any potential hazards.

The cost of this project is estimated at $34,100.

It is anticipated that this project will be completed in late August of 2022.

Stratford – Albert St (West of Nile St)

The scope of this project is a 3-Phase circuit upgrade & extension along Albert St. One pole will be replaced as part of this project and the remaining concrete poles along Albert St will be reframed to accommodate a 3-Phase overhead circuit. The purpose of this project is to create a primary circuit loop for a large number of commercial and residential downtown customers, which should eliminate long outages as part of some upcoming switchgear replacement work. The new circuit will also provide additional long-term operating flexibility for the area and will eliminate scheduled outages as part of future cable replacement and transformer replacement projects.

The cost of this project is estimated at $48,400.

It is anticipated that this project will be completed in late-April of 2022.

Seaforth – Coleman St (Gouinlock St to Highway 8)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a single-phase primary & secondary pole line on Coleman St between Gouinlock St and Highway 8. This project will see the replacement of 8 wood poles (new poles to be wood) with new primary and secondary conductors. The project spans approximately 200 meters. The poles and primary conductors are over 50 years old and are some of the oldest in FHI's system. A small portion of rear-yard overhead primary will be eliminated as part of this work and provisions will be made to install a 3 Phase circuit along Coleman in the future as part of a potential 27.6kV upgrade.

The cost of this project is estimated at $41,900.

This project is expected to start in mid-April and should take 2-3 weeks to complete.

Brussels – McCutcheon St (Turnberry St to Sports Dr)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a 3-phase primary pole line on McCutcheon St between Turnberry St and Sports Dr. This project will see the replacement of 6 wood poles (new poles to be wood). The pole and conductors are approximately 50 years old. The poles are only 35’ feet in height, which is quite low for a pole line that supports a 3-phase circuit. The primary and secondary conductors are to be replaced as part of the project. The project spans approximately 250 meters.

The cost of this project is estimated at $49,200.

This project is expected to start in early May and should be completed in late May.

Brussels – Orchard Lane (Halliday St to West Town Limit)

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of a single-phase primary pole line on Orchard Lane, west of Halliday St. This project will see the replacement of 11 wood poles (new poles to be wood). The pole and conductors are approximately 60 years old. The primary and secondary conductors are to be replaced as part of the project and 2 spans of overhead primary circuit on private property are to be eliminated as well. The project spans approximately 375 meters.

The cost of this project is estimated at $56,900.

This project is expected to start in early June and should be completed in late June.

Stratford & St. Mary's – Reinsulate Poles

With the majority of Stratford circuits completed, the focus of this project will shift to St. Mary's as there has been a significant increase in momentary outages over the last few years. Analysis of the outage causes indicates that animal contacts are the major cause of momentary outages, and further inspection of the feeder suggests the clearance from primary conductor to pole is insufficient to prevent squirrel contacts.

This scope of this project is to install fiberglass extension brackets on the existing insulators (also upgrading the insulators in St. Mary's) and to replace any metallic fasteners as a means of increasing clearances on the concrete poles. The scope of the project will also include the installation of animal guards on or around poles that are difficult to re-insulate. The focus in 2022 will be on heavily treed areas in St. Mary's where 3 phase circuits are present.

The cost of this project is estimated at $75,000

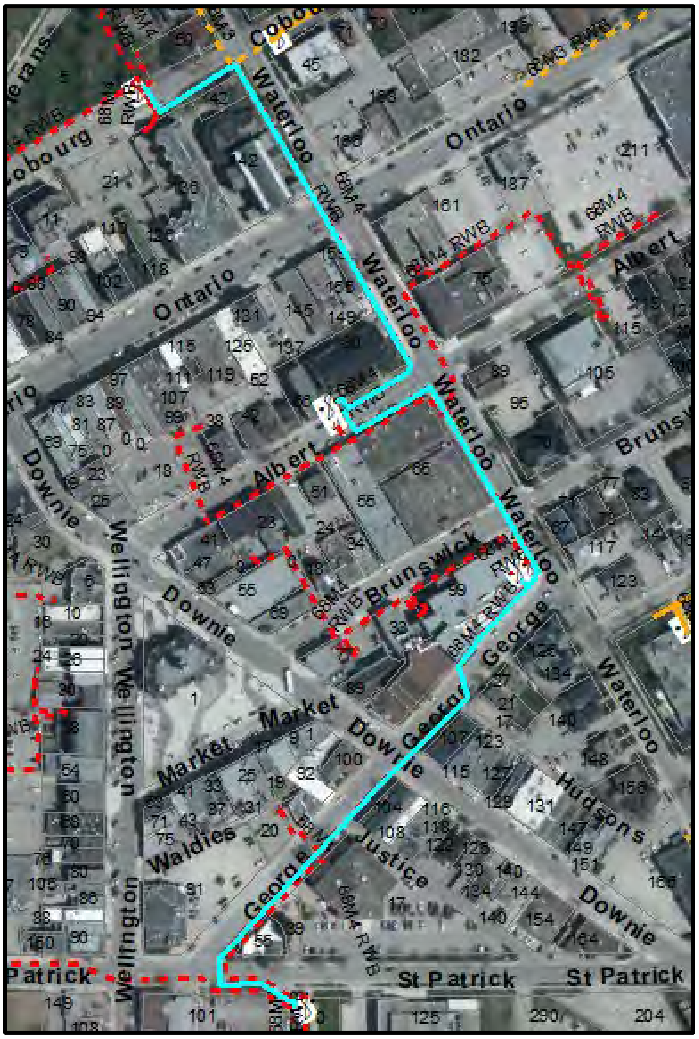
If this project is not completed, the Stratford & St. Mary's feeders will be at risk of high outages due to animal contacts.

This project is expected to start in January 2022 and be completed by December 31, 2022.

Stratford – M4 Feeder Upgrade – Phase 5

This project will replace aging infrastructure that has been identified as a potential risk for failure.

This section of the Stratford 68M4 Feeder cable is reaching its end of life. The cable is close to 40 years old. Approximately 2,800m of new TRXLPE 500MCM cable will be installed in existing duct to replace the existing cable along Cobourg St, Waterloo St, Albert St, George St and St. Patrick St.



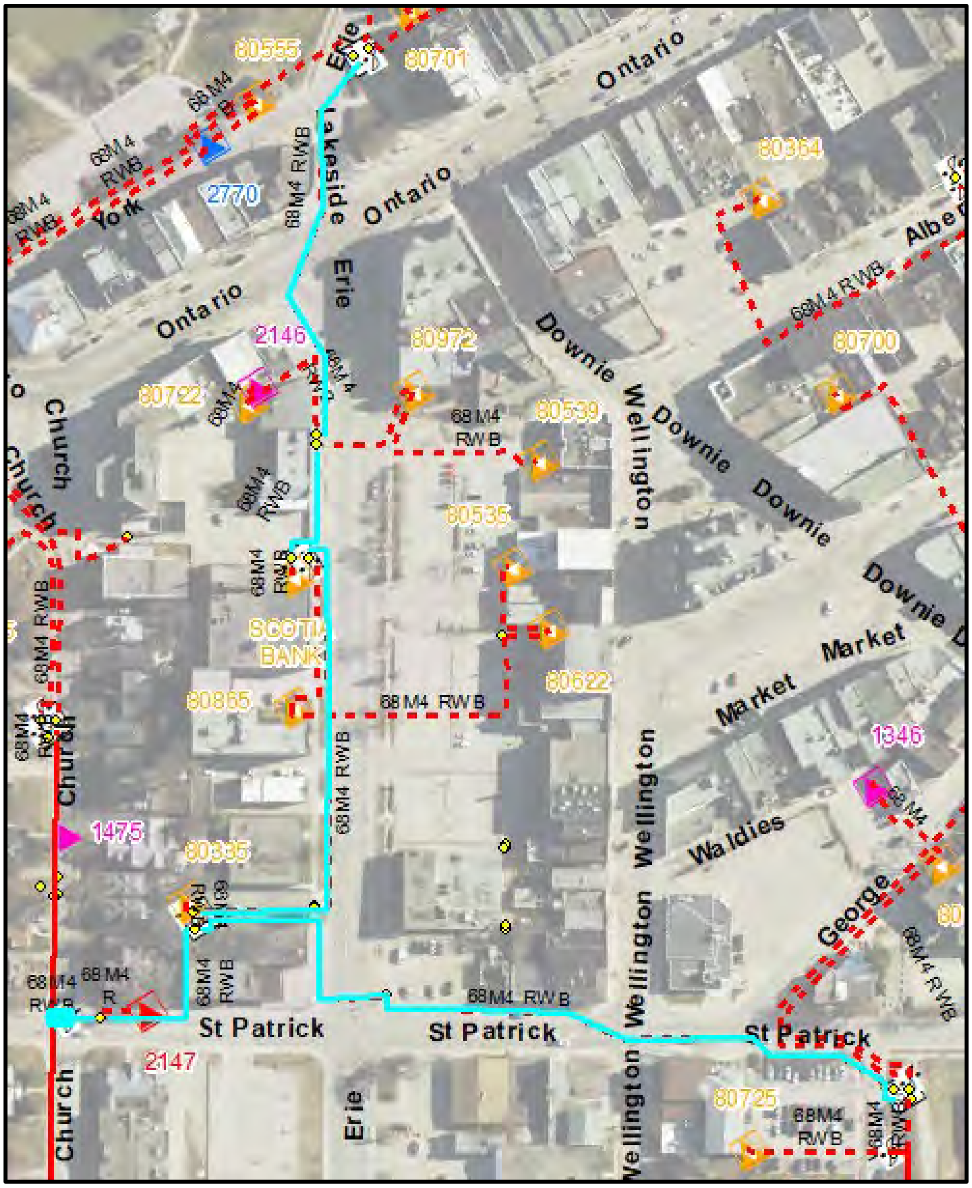
The cost of this project is estimated to be $331,500

If this project is not completed, the Stratford 68M4 feeder will be at risk of significant future outages due to equipment failure.

This project is expected to start in mid-May and to be completed in mid to late-June. This will be the last phase of this 5-year project.

Stratford – Erie St & St. Patrick St Cable Replacement Phase 2

This project will replace aging infrastructure that has been identified as a potential risk for failure.



This section of underground primary distribution cable is reaching its end of life. The cable is over 35 years old and services a significant number of commercial and residential customers in the downtown core. Approximately 1000m of new TRXLPE 1/0AWG insulated cable will be installed in existing duct to replace the existing cable. This will be Phase 2 of a 2-year project. The overall goal will be to eliminate an additional switchgear and reconfigure the existing primary circuits to allow more long-term operating flexibility.

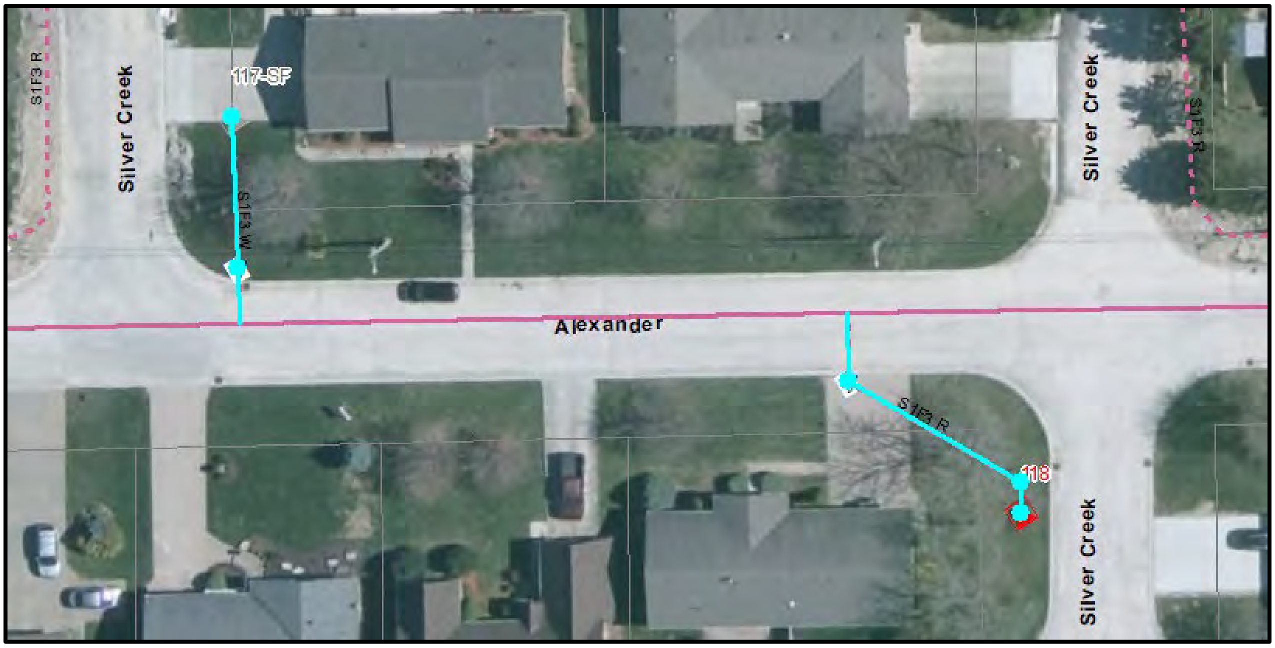
The cost of this project is estimated to be approximately $95,200 and will be completed in July.

Stratford – Albert St & Brunswick St Circuit Ties

The scope of this project is to install new underground primary cable to tie existing radial circuits together. This will help to drastically reduce the number of customers that will be impacted as part of a switchgear replacement in the downtown core and will also provide additional long-term operating flexibility for future cable replacement and transformer replacement projects.

The cost of this project is estimated to be approximately $35,400 and will be completed in early May.

Seaforth – Alexander Rd & Silver Creek Cres URD Cable Replacement



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of the project includes the replacement of underground primary conductors and transformers that service residential customers on Alexander St and Silver Creek Cres in Seaforth. The underground cable is approximately 40 years old and is reaching end of life.

The cost of this project is estimated to be $21,500.

This project is expected to be completed in early May.

Padmounted Switchgear Replacements

Before 2012 all padmounted switchgear installations were live front design. These installations had several inherent issues associated with them including: the possibility of animal and vegetation contact and personnel safety. FHI conducts regular inspections of our padmounted switchgear including yearly infrared surveys to identify any potential issues. Several years ago, FHI started a capital program to begin phasing out our live front units in favour of dead front units or through system design changes that make the padmounted switchgear redundant and therefore they are removed from service not replaced.

The typical life expectancy for padmounted switchgear is 30 years. In the case of assets such as transformers FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. This is not the case for switchgear, as the inherent design flaws make it desirable to replace these units as soon as they reach the end of their useful life.

Stratford - 2 Switchgears To Be Replaced, 1 Switchgear To Be Eliminated

By the end of 2021, there are expected to be 3 - 25kV livefront, padmounted switchgear units in service in Stratford. As part of the 2022 budget the plan is to replace 2 switchgears and eliminate 1 by reconfiguring the primary circuits that the switchgears are currently connected to. After this project is completed, there will be no more live-front switchgears in service in Stratford.

The cost of this project is estimated to be $104,100.

This project is expected to be completed by November 2022.

St. Mary's - 2 Switchgears To Be Eliminated

There are currently eight 15kV livefront, padmounted switchgear units in service in St. Mary's. As part of the 2022 budget the plan is to eliminate 2 switchgears by replacing them with insulated above ground or below ground connections, as those 2 switchgears are currently not fully utilized. Solutions for the remaining 6 switchgears will be explored throughout 2022, as they are a different design than the units used in Stratford.

The cost of this project is estimated to be $20,400.

This project is expected to be completed in the spring of 2022.

Transformers

Additional transformers needed due to load growth, replacements, conversions, emergency stock and new developments are expected to cost $195,075. This amount is comparable to previous years and takes historical figures into account. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

Miscellaneous Projects & Capital Additions

Miscellaneous projects are work that is unbudgeted but requires completion in the calendar year including: unsafe infrastructure requiring immediate replacement, cable failures etc. typically found during inspections or unplanned system faults. This budget ID is meant to deal with immediate system issues. Over the last few years, dozens of poles have been replaced as part of this program. Because of our current 4-year cycle for wood pole inspections, there were no wood poles inspected in 2021 and no immediate hazards were identified as part of a formal inspection process.

In 2022 the focus will be on pole replacements that were identified as lower risk from the previous years' inspections or that engineering, or operations staff have identified as potential hazards throughout 2021 site visits or customer inquiries. It is anticipated that approximately 10-12 poles would be replaced as part of this program. The cost of this work is estimated at $95,000.

Capital Additions are customer driven work including pole line extensions, transformer installations, subdivision work etc. This budget ID is completely customer driven and both sections are based on historical spending.

The cost of each of Miscellaneous Projects and Capital Additions is $289,231 and $280,908 respectively. These budgets take into account the previous five-year historical average spending.

New and Upgraded Services

Capital costs associated with the connection of new or upgraded residential and commercial secondary services. This section is customer driven and based on historical spending. The cost of this section is estimated at $195,075.

Metering

Capital costs associated with meter replacements and upgrades will be $387,149. This value takes into account historical growth rates and potential meter replacements for residential, commercial and Industrial installations. With a number of residential developments under construction, it is expected a portion of the budget will be spent on new residential meters. Investments will also be made into primary metering equipment including meters and Instrument transformers to be used for replacement and spares as well as LTE modems to support MIST meters and other interval meters where other modes of communication may be unsuitable.

Transformer Station

Capital costs associated with Transformer Station asset replacements and upgrades will be $139,000. T1 SEL relays, T1 RTU's and the T2 Qualitrol TMS (Temperature Monitoring System) are approaching end of life and will be repaired or replaced as lead times, programming and commissioning times may be extensive. A replacement AC Inverter for the station will be included as repair costs are becoming near level with the cost of replacement.

Distribution Stations

No capital work is planned for the Distribution Stations in Seaforth in 2022.

Fleet

One new, large vehicle and one 2021 carryover vehicle are included in the capital plan for purchase in 2022. The 2021 carryover is a new pickup truck will be purchased to replace Truck 7 (2009) used for Locating and Maintenance. The new, large vehicle is a single bucket truck to replace Truck 6 (2005). The estimated cost and associated budget is $60,000 for the pickup and $150,000 as a deposit for the single bucket truck as lead times could be up to two years. The total budget is $210,000

Computer Equipment/Hardware

In order to maintain lifecycle management of IT assets to effectively support business operations, the planned IT Hardware budget amounts to $192,500. The majority of the is budget is set for new Hypervisor hardware at $107,400. Cyber security related hardware accounts for $52,495 for backups, firewalls and video data recording systems and the remainder will be spent on general hardware.

Tools

Tools and miscellaneous equipment costs will be $30,000. Most of the purchases are for expected replacements of existing tools and equipment as they reach end of life.

Lands and Buildings

The Lands and Buildings budget includes items related to the Administration Building and various Service Centre projects. The Admin building work includes Engineering and Architecture work in addition to parking lot asphalt repairs and line painting touch-ups along with some office furniture at a value of $36,125.

Admin building improvements include painting the first and second floor hallways, renovations to the stairwell and preparation of interim offices needed to complete future renovation projects at a total budget of $48,500. Originally a major renovation to the Customer Service and Accounting areas was planned but budget in 2022 will be deferred to 2023 as the costs were forecast to be larger than what was forecast in the 5-year capital plan.

2022 Investments for the Service Centre include automated security gates, asphalt fencing repairs, roofing heat trace, line painting and several smaller facilities projects that will provide improvement to the work area and health and safety conditions for a budget amount of $190,067.

The total Lands and Buildings budget for 2021 is $274,692.

Replacement

Replacement projects are selected as part of the asset management plan and distribution system planning process, which look to keep system conditions stable to slightly improving over time. Most budget ID's contain some element of replacement projects, excluding the customer driven sections. Replacement projects represent $2.888 million dollars of the 2022 budget.

GIS Services

External GIS services have been capitalized in the amount of $110,000. This will be utilized throughout various distribution projects to support asset data management. This budget amount is also included in the Replacement figure above.

Growth Related Work

New and upgraded residential and commercial developments represent approximately $767,095 of the budget. This work is customer driven and the growth rates of the communities in the Festival Hydro service territory in 2022 are expected to be consistent with the 5-year average between 2015 and 2019.

New Technology

Technology spending in 2022 occurs in the areas of IT and SCADA. Within this budget is a proposed software spending of $261,800 broken down into the below groups:

Daffron software – based on historical spending patterns supporting custom programming changes to support OEB mandated regulations, we have requested $30,000 to support any item falling into this category.

Festival Hydro Website – We currently host our Festival Hydro website through London Hydro and have contracted with them to update our current website management platform. Spending on the Website and Customer Software is budgeted at $38,792.

Cyber Security – Various areas of spending are budgeted to continue to support compliance with the OEB CS framework and to address items related to the Digital Boundaries assessment previously conducted. Budgeted software items include mobile device management, endpoint protection and Application control, multifactor authentication, email scanning, secure map access, data loss prevention, Office 365 monitoring and password quality tools. This work is budgeted at $72,968.

Two roadmap projects are also budgeted in 2022 and include implementing SmartMap which will enable a platform for an Outage Management System (OMS), Engineering analysis software and transformer loading applications to name a few. Also, a project is planned to digitize the service order process from open to close using Go360 Contact Centre. The budgeted cost of these projects is $95,000.

SCADA projects include projects involving hardware replacements and upgrades, SCADA HMI updates related to the transformer station and field assets. Additional Fault Current Indicators (FCI's) are also planned for installation and various locations in the distribution system. The SCADA budget is planned at $55,000.

The total cost of these New Technology projects is estimated at $275,500.

FESTIVAL HYDRO INC.
2022 CAPITAL BUDGET

DISTRIBUTION PLANT		2022 BUDGET
Overhead Distribution Projects		**$ 602,300**
	Blake St - Dufferin to Burritt St (2021 Carryover)	$ 60,000
	Moderwell St - OH Rebuild	$ 43,500
	Romeo St S (Park to Frederick) - OH Rebuilnd	$ 104,000
	Cedar St - OH Rebuild	$ 34,100
	Glastonbury Dr (Warwick Brett) - OH Rebuild	$ 39,200
	West Gore St (Cooper Standard Service) - OH Rebuild	$ 37,600
	Albert St - Nile to Waterloo (3PH OH Extension - 1 pole change)	$ 48,400
	Coleman St (Gouinlock to Hwy. 8)	$ 41,900
	McCutcheon Dr (Turnberry to Sports)	$ 49,200
	Orchard Ln (West of Halliday)	$ 56,900
	Pole Line Design (Approximately 25 poles)	$ 12,500
	Reinsulating	$ 75,000
Underground Distribution Projects		**$ 818,100**
	Erie St & St Patrick St - UG Cable Replacement (2021 Carryover)	$ 100,000
	68M4 Feeder Upgrade - Phase 5	$ 331,500
	68M4 - Erie St & St. Patrick St Cable Replacement PH2	$ 95,200
	Switchgears - 1 PMH-9 (Labour Only), 1 PMH-12 (Maple & Dufferin)	$ 104,100
	68M4 - Albert St & Brunswick St Circuit Ties	$ 35,400
	Switchgears - 2 Removals (Queen St E, Southvale Rd)	$ 20,400
	Alexander Rd & Silver Creek Rd URD Cable Replacement	$ 21,500
	GIS	$ 110,000
Distribution Transformers-Purchases only-no labour		**$ 195,075**
Capital Additions - FHI Driven		**$ 289,231**
Capital Additions - Customer Driven		**$ 280,908**
New/Upgraded Services		**$ 195,075**
Distribution Meters		**$ 387,149**
Distribution Automation		**$ 55,000**
	Scada Enhancements	$ 55,000
Tools & Misc. Equipment		**$ 30,000**
	Tools - Operations	$ 25,000
	Misc Purchases	$ 5,000
Transformer Station		**$ 139,000**
	TS Capital (T1 SEL's, AC Inverter, T! RTU, T2 TMS)	$ 139,000
	DISTRIBUTION PLANT SUBTOTAL	**$2,991,838**
GENERAL PLANT		**2022 BUDGET**
Lands and Buildings		**$ 274,692**
	Administration Building Various	$ 36,125
	Administration Building Improvements	$ 48,500
	Service Centre	$ 190,067
Vehicles and Trailers		**$ 210,000**
	Pickup 2500 Locator/Maint replace Trk 7 (2021 Carryover)	$ 60,000
	Bucket Truck (Single) replace Truck 6 (2005)	$ 150,000
Computer Equipment		
	Software Purchases	**$ 261,800**
	Go360 Contact Centre and SmartMap	$ 95,000
	CIS Software	$ 73,800
	Cyber Security	$ 73,000
	Generic Software	$ 20,000
	Hardware Purchases	**$ 192,500**
	Cyber Security	$ 52,500
	Generic Hardware and Devices	$ 140,000
	GENERAL PLANT SUBTOTAL	**$938,992**
	DISTRIBUTION & GENERAL PLANTS TOTAL	**$3,930,830**

2023 Capital

Overhead

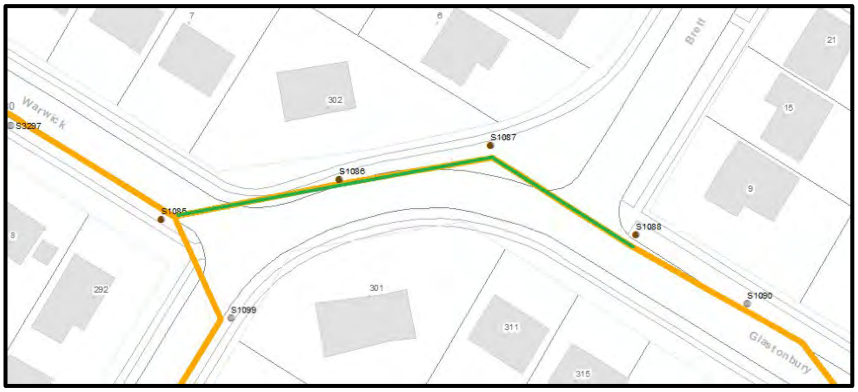
Stratford – Cedar St from Pine St to End of Line (2022 carryover)

This project is the replacement of 4 wood poles (new poles to be concrete) and overhead primary conductor on Cedar St. The poles are in poor condition and the primary conductors are supported by wooden crossarms and porcelain insulators. The primary conductors also cross an industrial facility and upgrading the supporting structures will reduce the risk of any potential hazards.

The cost of this project is estimated at $34,100.

This project is expected to start in Q1 with a duration of approximately 2 weeks.

Stratford – Glastonbury Dr from Warwick Rd to Brett St (2022 carryover)



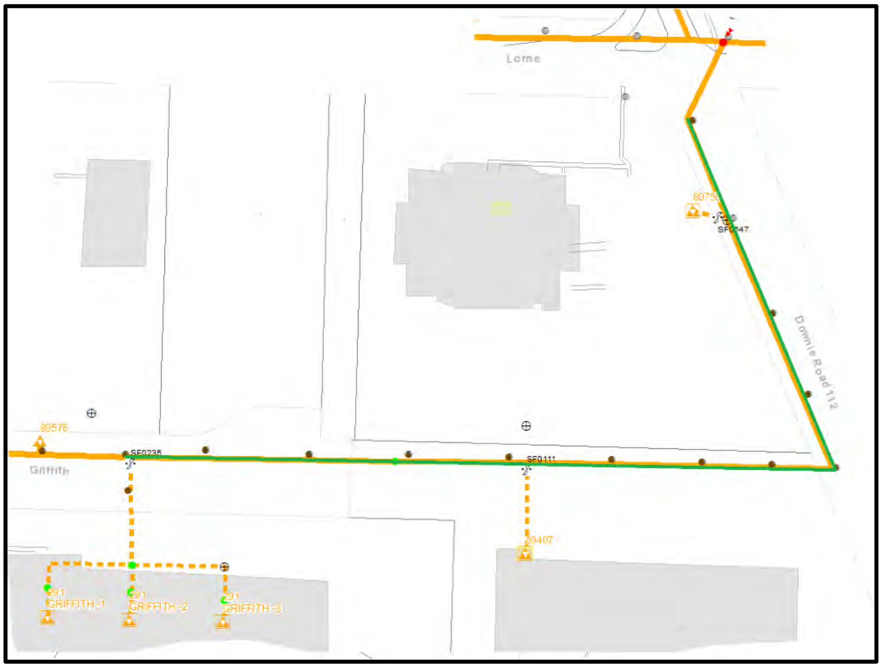
This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of 3 wood poles (new poles to be concrete) along Glastonbury Dr between Warwick Rd and Brett St. The project spans approximately 100 meters. Primary and secondary conductors are to be transferred as part of this project. The majority of poles, primary conductors and insulators over 50 years old and are in relatively poor condition. As part of the Warwick Rd rebuild in 2021, crews identified that these poles were in very poor shape near the top of the poles and as a result of that the rebuild of this section was given increased priority.

The total cost of this project is estimated at $39,200, with $29,000 of the work taking place in 2023.

This project is expected to start in Q1 with a duration of approximately 2 weeks.

Stratford – Downie St and Griffith Rd from Lorne Ave to 291 Griffith Rd



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of 13 wood and concrete poles (new poles to all be concrete) along Downie St from Lorne Ave to Griffith Rd and on Griffith Rd from Downie St to 291 Griffith Rd. The project spans approximately 500 meters. New conductors and transformers will be installed as part of this project. The majority of poles, primary conductors and insulators are over 50 years old and are in relatively poor condition as identified through inspections and pole testing. This will be a multi-year project until all of Griffith Rd is rebuilt.

The cost of this project is estimated at $215,000.

This project is expected to start in Q2 with a duration of approximately 8 weeks.

Stratford – Youngs St from Birmingham St to St. Vincent St

This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of 6 wood poles (new poles to be concrete) along Youngs St between Birmingham St and St. Vincent St. The project spans approximately 175 meters. New primary conductor and transformers will be installed, while secondary will be transferred to the new poles. The majority of poles, primary conductors and insulators over 50 years old and are in relatively poor condition as identified through inspections and pole testing.

The cost of this project is estimated at $45,000.

This project is expected to start in Q2 with a duration of approximately 3 weeks.

Seaforth – Oak St. to Railroad tracks

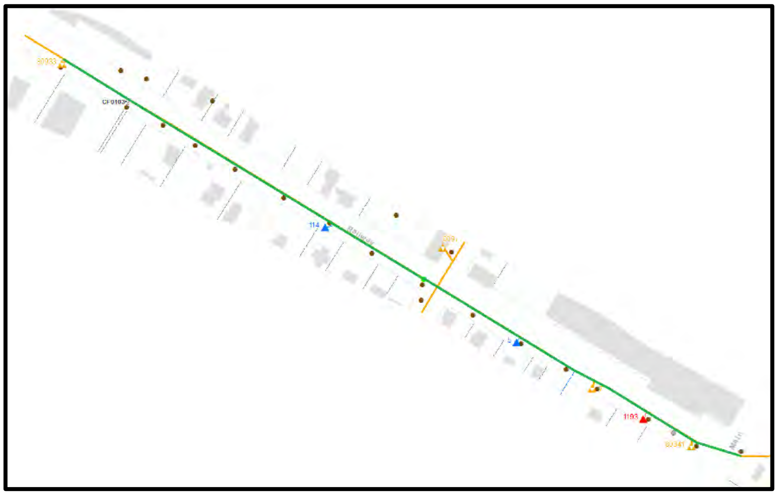
This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of 10 wood poles (new poles to be wood) through an industrial area between Oak St and railroad tracks, including crossing the railroad. The project spans approximately 200 meters. New primary conductor and transformers will be installed, while secondary will be transferred to the new poles. The majority of poles, primary conductors and insulators over 50 years old and are in relatively poor condition as identified through inspections and pole testing.

The cost of this project is estimated at $125,000.

This project is expected to start in Q4 with a duration of approximately 6 weeks.

Seaforth – Railway St from Main St to Sparling St



This project will replace aging infrastructure that has been identified as a potential risk for failure.

The scope of this project is a replacement of 13 wood poles (new poles to be wood) along Railway St from Main St to Sparling St. The project spans approximately 500 meters. New conductors and transformers will be installed as part of this project. The majority of poles, primary conductors and insulators over 45 years old and are in relatively poor condition as identified through inspections and pole testing.

The cost of this project is estimated at $148,000.

This project is expected to start in Q3/Q4 with a duration of approximately 7 weeks.

Seaforth – Daly St from Sparling St to 82 Daly St

This project will install new primary conductor to maintain a redundant loop on Daly St while eliminating a primary line running through private property.

The scope of this project is the addition of 3 wood poles along Daly St from Sparling to the existing pole line at 82 Daly St. The project spans approximately 125 meters. New conductors and transformers will be installed as part of this project. The majority of poles, primary conductors and insulators to be removed are over 45 years old, are in relatively poor condition and are difficult to access given their location is not on the public right of way.

The cost of this project is estimated at $32,500.

This project is expected to start in Q3 with a duration of approximately 2 weeks.

St. Mary's – Reinsulate Poles

The focus of this project shifted to St. Mary's in 2022 and remains in 2023 as there has been a significant increase in momentary outages over the last few years. Analysis of the outage causes indicated that animal contacts are the major cause of momentary outages, and further inspection of the feeder suggests the clearance from primary conductor to pole is insufficient to prevent squirrel contacts.

This scope of this project is to install fiberglass extension brackets on the existing insulators, while also upgrading the insulators, and to replace any metallic fasteners as a means of increasing clearances on the concrete poles. The scope of the project will also include the installation of animal guards on or around poles that are difficult to re-insulate. The focus will continue to be on heavily treed areas in St. Mary's where 3 phase circuits are present.

The cost of this project is estimated at $82,500.

This project is expected to start in Q1 with a duration of approximately 4 weeks.

Underground

Brussels – Krauter Crt

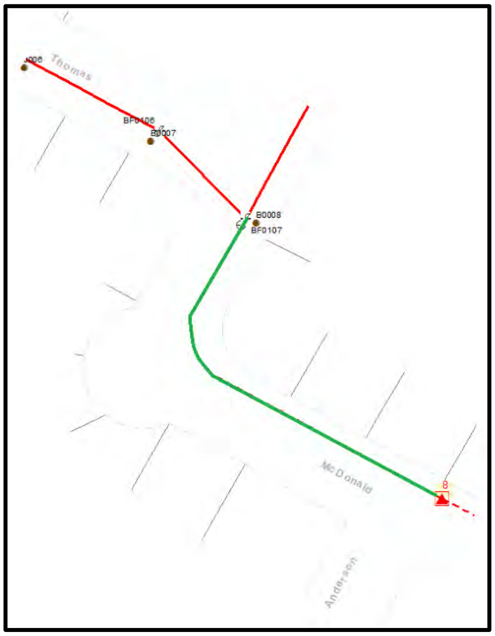
This project will replace aging infrastructure that has the potential risk for failure.

The scope of the project includes the removal of underground primary conductor and a padmount transformer that service residential customers on Krauter Crt in Brussels. This will be replaced with a pole mount transformer and new underground secondary conductor. The underground cable is over 40 years old and is reaching end of life.

The cost of this project is estimated to be $20,600.

This project is expected to start in Q3 with a duration of approximately 1 week.

Brussels – McDonald Dr



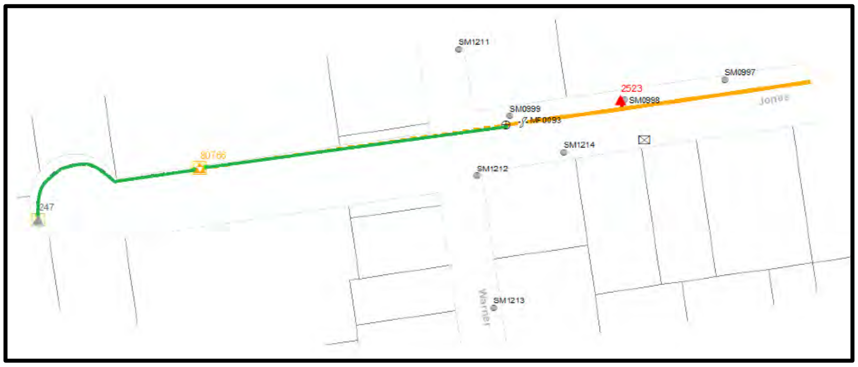
This project will replace aging infrastructure that has the potential risk for failure.

The scope of the project includes the replacement of approximately 70 meters of single phase underground primary conductors and transformers that service residential customers on McDonald Dr in Brussels. The underground cable is over 40 years old and is reaching end of life.

The cost of this project is estimated to be $38,900.

This project is expected to start in Q3 with a duration of approximately 1 week.

St. Marys – Jones St W



This project will replace aging infrastructure that has the potential risk for failure.

The scope of the project includes the replacement of approximately 150 meters of three phase underground primary conductors and transformers that service customers on Jones St W in St. Marys. The underground cable is over 40 years old and is reaching end of life.

The cost of this project is estimated to be $58,300.

This project is expected to start in Q3 with a duration of approximately 1 week.

St. Marys – Elgin St E, Cain St and Hillside Ct

This project will replace aging electrical and civil infrastructure that has the potential risk for failure.

The scope of the project includes the installation of new ducts, and replacement of approximately 1300 meters of single phase underground primary conductors and transformers that service residential customers on Elgin St, Hillside Ct and Cain St in St. Marys. Currently all 11 transformers are fed radially, and this project will also include the looping of underground cables to provide redundancy in this area for outage and maintenance purposes. The underground cable is over 40 years old and is reaching end of life.

The cost of this project is estimated to be $374,550.

This project is expected to start in Q2 with a duration of approximately 6 weeks.

Padmounted Switchgear Replacements

Before 2012 all padmounted switchgear installations were live front design. These installations had several inherent issues associated with them including: the possibility of animal and vegetation contact and personnel safety. FHI conducts regular inspections of our padmounted switchgear including yearly infrared surveys to identify any potential issues. Several years ago, FHI started a capital program to begin phasing out our live front units in favour of dead front units or through system design changes that make the padmounted switchgear redundant and therefore they are removed from service not replaced.

The typical life expectancy for padmounted switchgear is 30 years. In the case of assets such as transformers FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. This is not the case for switchgear, as the inherent design flaws make it desirable to replace these units as soon as they reach the end of their useful life.

This project is expected to start in Q3 with a duration of approximately 2 weeks.

St. Mary's - 2 Switchgears To Be Replaced

There are currently six 15kV livefront, padmounted switchgear units in service in St. Mary's. As part of the 2023 budget the plan is to replace 2 switchgears with new units, as well as purchase a spare that will be able to be used on any switchgear needed in St. Marys to minimize any extra stock required.

The cost of this project is estimated to be $321,700.

Transformers

This section accounts for transformers needed due to load growth, replacements, conversions, emergency stock and new developments. This amount is slightly higher than previous years due to the large underground project in St. Mary's to replace 11 padmount transformers. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

The proposed transformers budget for 2023 is estimated at $315,000.

Miscellaneous Projects & Capital Additions

Miscellaneous projects are work that is unbudgeted but requires completion in the calendar year including: unsafe infrastructure requiring immediate replacement, cable failures etc. which are typically found during inspections or unplanned system events. This budget item is meant to deal with immediate system issues. Over the last few years, dozens of poles have been replaced as part of this program. There were 1,100 wooden poles tested in 2022 to prepare for Festival Hydro's upcoming Cost of Service application and 2 poles will be replaced as a result of these inspections identifying the need for immediate replacement. It is anticipated that in total approximately 12-15 poles will be replaced as part of this program with the remaining poles to be replaced focusing on those that were identified as lower risk from the previous years' inspections or that Engineering or Operations staff have identified as potential hazards throughout 2022 site visits or customer inquiries. The cost of this work is estimated at $105,000.

Capital Additions are customer driven work including pole line extensions, transformer installations, subdivision work etc. This budget item is completely customer driven and both sections are based on historical spending.

These budgets take into account the previous five-year historical average spending and any known upcoming projects that may cause deviations from historical spending averages.

The proposed miscellaneous projects and capital additions budget for 2023 is estimated at $303,450 and $275,000 respectively.

New and Upgraded Services

Capital costs associated with the connection of new or upgraded residential and commercial secondary services. This section is customer driven and based on historical spending.

The proposed new and upgraded services budget for 2023 is estimated at $195,000.

Metering

This value takes into account historical growth rates and potential meter replacements for residential, commercial and industrial installations. With numerous residential developments under construction, it is expected a portion of the budget will be spent on new residential meters. Investments will also be made into primary metering equipment including meters and instrument transformers to be used for replacement and spares as well as LTE modems and meters to support MIST meters and other interval meters where other modes of communication may be unsuitable. Budget has also been allocated in 2023 to hire a consultant to assist Festival Hydro in completing an RFP to select a vendor for the needed AMI 2.0 redeployment.

The proposed metering budget for 2023 is $335,000.

Transformer Station

The T1 RTU, AC UPS inverter, spares for critical protection and control equipment and new DC battery bank will comprise the capital projects for 2023.

The proposed transformer station budget for 2023 is $165,000.

Distribution Stations

No capital work is planned for the Distribution Stations in Seaforth in 2023.

Fleet

One new pickup truck is included in the capital plan for purchase in 2023. The new pickup truck will be purchased to replace Truck 7 (2009) used for Locating and Maintenance. A new single bucket truck to replace Truck 6 (2005) has been tendered, but delivery will not occur until Q3 2024 and therefore money has not been allocated for it in 2023.

The proposed fleet budget for 2023 is $75,000.

Computer Equipment/Hardware

The majority of the is budget is set for new switches for network access control and servers for firewalls at $140,000. The remainder will be spent on general hardware to maintain lifecycle management of IT assets as well as new devices to facilitate use of SmartMAP and Go360 by Operations crews in the field.

The proposed computer equipment/hardware budget for 2023 is $313,169.

Tools

Most of the purchases in this category are for expected replacements of existing tools and equipment as they reach end of life.

The proposed tools and miscellaneous equipment budget for 2023 is $30,000.

Lands and Buildings

The Lands and Buildings budget includes items related to the Administration Building and various Service Centre projects. The Admin building work includes the replacement of a retaining wall on Festival Hydro property that is structurally unsound as well as general upkeep items for an estimated budget of $38,040.

Admin building improvements include a major renovation to the Customer Service and Accounting areas. This will provide space for all current and potential future employees and includes the cost to re-furnish the entire area along with all trades work needed. It will also include the replacement of a damaged main sewer drain from the building out to Erie St. which runs beneath the Customer Service area and is most cost effective to replace at the same time as this renovation before a complete blockage occurs. The budget for these improvements are estimated at $875,000.

2023 Investments for the Service Centre are minimal and just for general upkeep of the building which are budgeted at $5,000.

The proposed lands and buildings budget for 2023 is $918,040.

Replacement

Replacement projects are selected as part of the asset management plan and distribution system planning process, which look to keep system conditions stable to slightly improving over time. Most budget ID's contain some element of replacement projects, excluding the customer driven sections.

The proposed replacement projects budget for 2023 is $3.794 million dollars.

GIS Services

External GIS services will be utilized throughout various distribution projects to support asset data management. This budget amount is included in the Replacement figure above.

The proposed GIS services budget for 2023 is $100,000.

Growth Related Work

This work is customer driven and the growth rates of the communities in the Festival Hydro service territory in 2023 are expected to be consistent with historical 5 year averages.

The proposed new and upgraded residential and commercial developments budget for 2023 is estimated at $795,000.

New Technology

Technology spending in 2023 occurs in the areas of IT and SCADA. Within this budget is a proposed break down of new technology into the below groups:

CIS Software Replacement – The current Daffron CIS is obsolete and finding resources that understand and can troubleshoot issues with the software is becoming more and more difficult. In 2023 $250,000 has been budgeted to procure a new CIS system.

Switches for Network Access – The current network switches are of various vintages and manufacturers. Replacement would allow Festival to pull the network switches into one unified management environment while decommissioning end-of-life equipment. These devices would also increase cyber defenses by enabling more intelligent network access control to ensure that no unauthorized devices can join the network. $100,000 has been budgeted in 2023 for this replacement.

SCADA projects include projects involving the installation of additional Fault Current Indicators (FCI's) in various locations in the distribution system as well as the replacement of a remote switch. The SCADA budget is planned at $75,000.

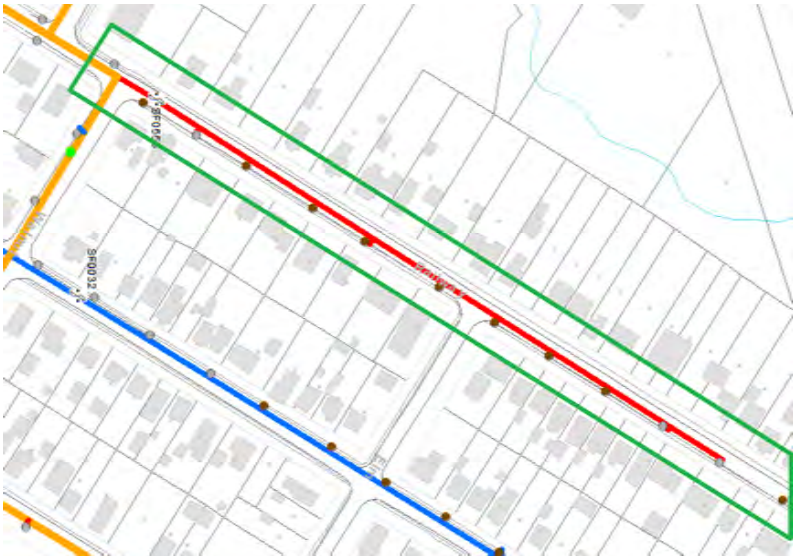
The proposed new technology budget for 2023 is $425,000.

FESTIVAL HYDRO INC. PROPOSED 2023 CAPITAL BUDGET		
	carryover	
DISTRIBUTION PLANT		**BUDGET**
Overhead Distribution Projects		**$786,900**
S	Cedar St - OH Rebuild	$ 34,100
S	Glastonbury Dr (Warwick Brett) - OH Rebuild	$ 29,000
S	Downie/Griffith - OH Rebuild (Lorne to 291 Griffith)	$ 215,000
S	Youngs St - West of Birmingham St - OH Rebuild	$ 45,000
SF	Oak St (Service Centre & Boilersmith Area/RR Tracks) - OH Rebuild	$ 125,000
SF	Railway St - Main St S to Sun North - OH Rebuild	$ 148,000
SF	Daily St - East of Sparlint St - OH Rebuild/Extension	$ 32,500
N/A	Pole Line Design (Approximately 43 poles)	$ 25,800
N/A	GIS Support	$ 50,000
SM	Reinsulating	$ 82,500
Underground Distribution Projects		**$898,950**
SM	2022 Carry Over (Switchgear Replacement)	$ 34,900
B	Krauter Court - URD Cable Removal - Install Secondary	$ 20,600
B	McDonald Dr - URD Cable Replacement	$ 38,900
SM	Jones St W - URD Cable Replacement	$ 58,300
SM	Elgin, Cain, Hillside - URD Cable Replacement	$ 374,550
SM	Switchgears - 3 Replacements (Ingersoll, Southvale, Queen)	$ 321,700
	GIS Support	$ 50,000
Distribution Transformers		**$ 315,000**
Capital Additions - FHI Driven		**$ 303,450**
Capital Additions - Customer Driven		**$ 275,000**
New/Upgraded Services		**$ 195,000**
Distribution Meters - Residential/Commercial/Industrial Meters		**$ 335,000**
	Services <50kW	$ 150,000
	Services >=50kW	$ 100,000
	CT's and PT's	$ 35,000
	SM 2.0 RFP	$ 50,000
Distribution Automation - SCADA Enhancements		**$ 75,000**
Tools & Misc. Equipment		**$ 30,000**
	Tools - Operations	$ 25,000
	Misc Purchases	$ 5,000
Transformer Station		**$ 165,000**
	TS Capital	$ 145,000
	TS Facilities	$ 20,000
Distribution Stations		
	DISTRIBUTION PLANT SUBTOTAL	**$3,379,300**
GENERAL PLANT		**BUDGET**
Lands and Buildings		**$ 918,040**
	Administration Building (Renovation, Sewer Replacement, Retaining Wall)	$ 38,040
	Administration Building Improvements (Renovation/Sewer Replacement)	$ 875,000
	Service Centre	$ 5,000
Vehicles and Trailers		**$ 75,000**
	Pickup Truck to Replace Truck 25	$ 75,000
Information Technology		
	Software Purchases	**$ 328,606**
	CIS Software Replacement	$ 250,000
	General Software	$ 78,606
	Hardware Purchases	**$ 313,169**
	General Hardware	$ 213,169
	Switches for Network access Control	$ 100,000
	GENERAL PLANT SUBTOTAL	**$1,634,815**
	GROSS DISTRIBUTION & GENERAL PLANTS TOTAL	**$5,014,115**
	FORECAST CAPITAL CONTRIBUTION	**-400,000**
	NET DISTRIBUTION & GENERAL PLANTS TOTAL	**$4,614,115**

2024 Capital

Overhead

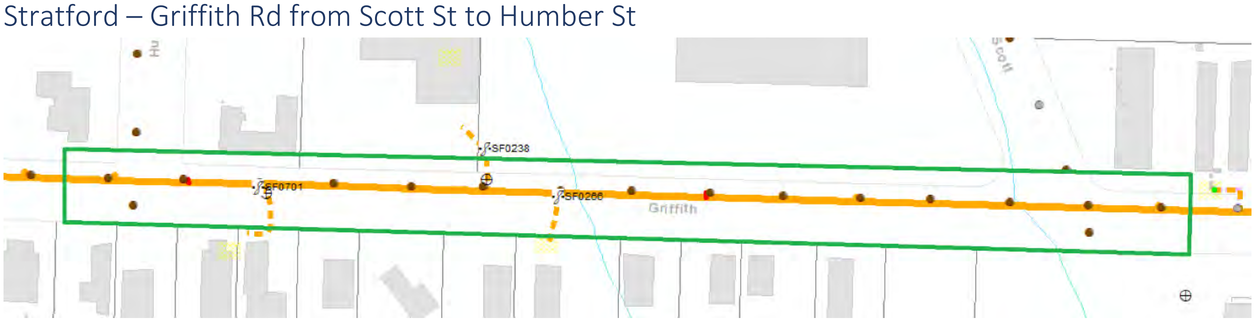
Stratford – Railway Ave from Walnut St to Nelson St



The scope of this project is the replacement of 9 wood poles (new poles to be concrete) and overhead primary conductor on Railway Ave. from Walnut St. to Nelson St. The project spans approximately 375 meters. Primary and secondary conductors, as well as transformers, are to be replaced as part of this project. The majority of poles, primary conductors and insulators are over 50 years old and are in relatively poor condition.

The cost of this project is estimated at $60,000.

Stratford – Griffith Rd from Scott St to Humber St



The scope of this project is a replacement of 16 wood poles (new poles to be concrete) on Griffith Rd. from Scott St. to Humber St. The project spans approximately 550 meters. New conductors and transformers will be installed as part of this project. The majority of poles, primary conductors and insulators are over 50 years old and are in relatively poor condition. This is a continuation of the Griffith Rd. project started in 2023.

The cost of this project is estimated at $215,000.

Dashwood – Highway 83 from eastern town boundary to Centre St.

The scope of this project is the replacement of 16 wood poles and overhead primary conductor on Highway 83 from the eastern boundary of Dashwood to Centre St. This project is being done in conjunction with the Township for a road reconstruction project and is a two part project, with the second phase being completed in 2025. The project spans approximately 400 meters. Primary and secondary conductors are to be replaced as part of this project. The majority of poles, primary conductors and insulators are over 50 years old and are in relatively poor condition.

The cost of this project is estimated at $142,000.

St. Marys – Industrial Rd from Queen St to end of road

The scope of this project is a replacement of 6 wood poles along Industrial Rd in St. Marys off of Queen St. The project spans approximately 175 meters. It will also move the pole line from the rear lot of all the industrial areas to boulevard to allow for easier connections in the future and easier maintenance of the line itself. New primary and secondary conductor will be installed, while transformers will be re-used. The majority of poles, primary conductors and insulators are over 40 years old and are in relatively poor condition as identified through inspections and pole testing.

The cost of this project is estimated at $155,200.

Seaforth – Goderich St E from Centennial Dr to Coleman St

The scope of this project is a replacement of 2 concrete poles and upgrading the area from 1-phase to 3-phase by adding two more conductors. This is being done to support the long-term upgrade of Seaforth from 4kV to 27.6kV. The project spans approximately 320 meters. New primary conductor and new dual voltage transformers will be installed; while secondary will be transferred to the new poles where applicable.

The cost of this project is estimated at $65,000.

St. Marys – Reinsulate Poles

The focus of this project remains in St. Marys in 2024 to continue addressing momentary outages from animal contacts in this area. In 2023, only a portion of this project was completed due to a material shortage of fiberglass brackets; however, all material is planned for delivery to allow the full scope of this work to take place in 2024.

The scope of this project is to install fiberglass extension brackets, while also upgrading the insulators to a higher voltage class, as well as replacing any metallic fasteners as a means of increasing clearances on the concrete poles as inspections have noted that clearance from primary conductor to concrete poles are currently insufficient to prevent squirrel contacts. The scope of the project will also include the installation of animal guards on or around poles that are difficult to re-insulate. The focus will continue to be on heavily treed areas in St. Marys where 3 phase circuits are present.

The cost of this project is estimated at $85,000.

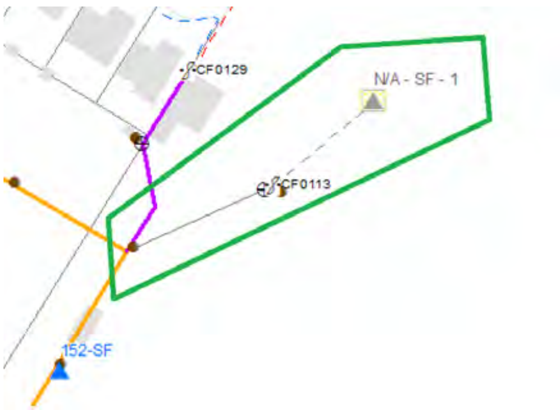
Underground

Seaforth – West William St.

The scope of the project includes the removal of underground primary conductor and a padmount transformer that service residential customers on West William St in Seaforth. This will be replaced with a pole mount transformer and new underground secondary conductor. The underground cable is over 35 years old and is reaching end-of-life.

The cost of this project is estimated to be $14,200.

Seaforth – Duke St.



The scope of the project includes the removal of underground primary conductor and a padmount transformer that service seasonal campground customers near Duke St in Seaforth. This will be replaced with a pole mount transformer and new underground secondary conductor. The underground cable is over 35 years old and is reaching end-of-life.

The cost of this project is estimated to be $30,100.

St. Marys – Station St from Widder St to Peel St

The scope of the project includes the removal of underground primary conductor and a padmount transformer that service residential customers on Station St. in St. Marys. This will be replaced with a pole mount transformer and new underground secondary conductor. The underground cable is over 35 years old and is reaching end-of-life.

The cost of this project is estimated to be $16,000.

St. Marys – Maxwell St from James St to Dunsford Cr

The scope of the project includes the installation of new ducts, and replacement of approximately 2km of single phase underground primary conductors and transformers that service residential customers on Maxwell St. and Dunsford Cr. in St. Marys. This project will also enable the looping of underground cables on Dunsford Cr to provide redundancy in this area for outage and maintenance purposes. The underground cable is over 30 years old and is reaching end-of-life. This is a multi-year project on Maxwell St. to update the entire subdivision.

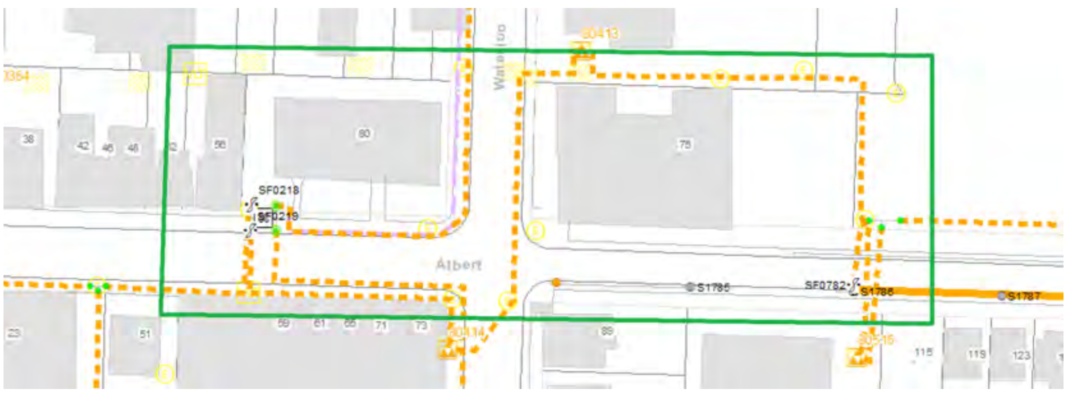
The cost of this project is estimated to be $348,600.

Stratford – Brunswick St. from Waterloo St to Downie St

The scope of the project includes the replacement of approximately 500 meters of three phase underground primary conductors that service commercial customers on Brunswick St. between Waterloo St. and Downie St. in Stratford. The underground cable is over 35 years old and is reaching end-of-life.

The cost of this project is estimated to be $37,900.

Stratford – Waterloo St and Albert St



The scope of the project includes the replacement of approximately 1.1km of three phase underground primary conductors that service commercial customers on Waterloo St. and Albert St. in Stratford. The underground cable is over 35 years old and is reaching end-of-life.

The cost of this project is estimated to be $62,000.

Stratford – Hibernia/Galt/Mccann

The scope of the project includes the replacement of approximately 750 metres of single phase underground primary conductors and transformers that service residential customers on Hibernia St., Galt Rd. and McCann Dr. Stratford. The underground cable is over 30 years old and is reaching end-of-life.

The cost of this project is estimated to be $180,900

Padmounted Switchgear Replacements

Before 2012, all padmounted switchgear installations were live front design. These installations had several inherent issues associated with them including: the possibility of animal and vegetation contact and personnel safety. FHI conducts regular inspections of our padmounted switchgear including yearly infrared surveys to identify any potential issues. Several years ago, FHI started a capital program to begin phasing out our live front units in favour of dead front units or through system design changes that make the padmounted switchgear redundant and therefore they are removed from service not replaced.

The typical life expectancy for padmounted switchgear is 30 years. In the case of assets such as transformers FHI aims to maximize the useful in-service life of assets beyond the depreciable life expectancy. This is not the case for switchgear, as the inherent design flaws make it desirable to replace these units as soon as they reach the end of their useful life.

St. Marys - 2 Switchgears To Be Replaced

After 2023 There are planned to be four 15kV livefront, padmounted switchgear units in service in St. Marys. As part of the 2024 budget, the plan is to replace 2 more switchgears with new units.

The cost of this project is estimated to be $205,800.

Transformers

This section accounts for transformers needed due to load growth, replacements, conversions, emergency stock and new developments. This amount is higher than previous years due to the large underground projects in St. Marys and Stratford. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

The proposed transformers budget for 2024 is estimated at $415,000.

Miscellaneous Projects & Capital Additions

Miscellaneous projects are work that is unbudgeted but requires completion in the calendar year including: unsafe infrastructure requiring immediate replacement, cable failures, rusted padmount transformers, etc. which are typically found during inspections or unplanned system events. This budget item is meant to deal with immediate system issues. Over the last few years, dozens of poles have been replaced as part of this program. All wooden poles in Festival Hydro's service territory were tested in 2022 and 2023 to prepare for Festival Hydro's upcoming Cost of Service application, and 2 poles will be replaced as a result of these inspections identifying the need for immediate replacement. It is anticipated that in total approximately 12-15 poles will be replaced as part of this program with the remaining poles to be replaced focusing on those that were identified as lower risk from the previous years' inspections or that Engineering or Operations staff have identified as potential hazards throughout site visits or customer inquiries.

Capital Additions are customer driven work including pole line extensions, transformer installations, subdivision work etc. This budget item is completely customer driven and both sections are largely based on historical spending. These budgets take into account the previous five-year historical average spending and any known upcoming projects that may cause deviations from historical spending averages.
The proposed miscellaneous projects and capital additions budget for 2024 is estimated at $312,573 and $275,000 respectively.

New and Upgraded Services

Capital costs associated with the connection of new or upgraded residential and commercial secondary services. This section is customer driven and based on historical spending.
The proposed new and upgraded services budget for 2024 is estimated at $195,000.

Metering

This value takes into account historical growth rates and potential meter replacements for residential, commercial and industrial installations. With numerous residential developments under construction, it is expected a portion of the budget will be spent on new residential meters. Investments will also be made into primary metering equipment including meters and instrument transformers to be used for replacement and spares. Money has also been allocated in 2024 to begin the process of our Smart Meter 2.0 deployment. This includes configuration and testing of a new head end system, along with integrations with external software and piloting a small installation, with mass deployment planned in 2025. Further details will be provided once further as the RFP process continues.

The proposed metering budget for 2024 is $400,000.

Transformer Station

In 2024 the majority of the spend will be on a replacement for the failed primary metering unit that occurred in 2023 and accompanying engineering design to retrofit into the existing structural footprint as there are no direct replacements available any longer.
The proposed transformer station budget for 2024 is $150,000.

Distribution Stations

No capital work is planned for the Distribution Stations in Seaforth in 2024.

Fleet

One new single bucket truck to replace Truck 6 (2005) is included in the capital plan for purchase in 2024. This was tendered and awarded in 2022, however given the lead times for these assets, the earliest delivery was 2024.

The proposed fleet budget for 2024 is $450,000.

Computer Equipment/Hardware

Spending for computer equipment and hardware in 2024 will be focused on lifecycle items such as laptop and mobile device replacement. A new envelope stuffer will be purchased for billing as the current device is nearing end-of-life.

The network access control project will be completed and enhanced with the installation of new wifi access points in the admin building.

The proposed computer equipment/hardware budget for 2024 is $193,069.

Tools

Most of the purchases in this category are for expected replacements of existing tools and equipment as they reach end-of-life.
The proposed tools and miscellaneous equipment budget for 2024 is $45,000.

Lands and Buildings

The Lands and Buildings budget includes items related to the Administration Building and various Service Centre projects.

Admin building improvements include the major renovation of it remainder of the first floor (I.T. and meeting room areas) as well as the entire second floor in subsequent stages. This will provide functional space for current and potential future employees, add meeting and lunch rooms to both floors for better accessibility, as well as adequate storage for metering equipment and workbenches. It also includes the cost to re-furnish the entire area along with all trades work needed. The budget for these improvements are estimated at $2,140,000 and will complete all interior renovations at the Admin building.

2024 Investments for the Service Centre are minimal and just for general upkeep of the building as well as a new racking system for outdoor equipment, which are budgeted at $25,000.
The proposed lands and buildings budget for 2024 is $2,165,000.

Replacement

Replacement projects are selected as part of the asset management plan and distribution system planning process, which look to keep system conditions stable to slightly improving over time. Most budget ID's contain some element of replacement projects, excluding the customer driven sections.

The proposed replacement projects budget for 2024 is $6.763 million dollars.

GIS Services

External GIS services will be utilized throughout various distribution projects to support asset data management. There is also a line item to replace our current installation of Esri's GIS software with the new Utility Network model. The reason for this is support for the existing platform is ending and no patches, updates or enhancements are being made to the existing software. The updated software model is also specifically geared to electric utilities and will better allow Festival Hydro to manage and track our assets. This budget amount is included in the Replacement figure above.

The proposed GIS services budget for 2024 is $180,000.

Growth Related Work

This work is customer driven and the growth rates of the communities in the Festival Hydro service territory in 2024 are expected to be consistent with historical 5 year averages.

The proposed new and upgraded residential and commercial developments budget for 2024 is estimated at $877,500.

New Technology

Technology spending for 2024 is primarily focused on ERP and Operational Technology (OT) systems.

ERP Replacement - The new ERP project will kick-off in 2024 and span both the 2024 and 2025 budget years. This is a significant project which will significantly improve capabilities and efficiency while dealing with the risk of lack of support and obsolescence of the current Daffron system. $875,000 has been budgeted for this project in 2024.

OT System Review - The design and security of OT systems will be reviewed in 2024 to create a strategic plan to be delivered in phases. The goal would be to complete the first phase of this plan within the budget year. This project will position us well as the OEB Cybersecurity framework and our insurer starts to address OT and supply chain risks. As well, it will provide valuable support for the AMI Refresh Project.

CIS Software Transition - The current Daffron CIS is obsolete and finding resources that understand and can troubleshoot issues with the software is becoming more and more difficult. The JOMAR CIS was selected and development of the new CIS started in 2023. In 2024 $285,250 has been budgeted to finish the project and transition to the new CIS system.

SCADA - SCADA projects include projects involving the installation of additional Fault Current Indicators (FCI's) in various locations in the distribution system as well as the finalization of making all smart switches fully automated in Stratford and St. Marys. The SCADA budget is planned at $76,500.

The proposed new technology budget for 2024 is $1,236,750.

FESTIVAL HYDRO INC.
2024 PROPOSED CAPITAL BUDGET

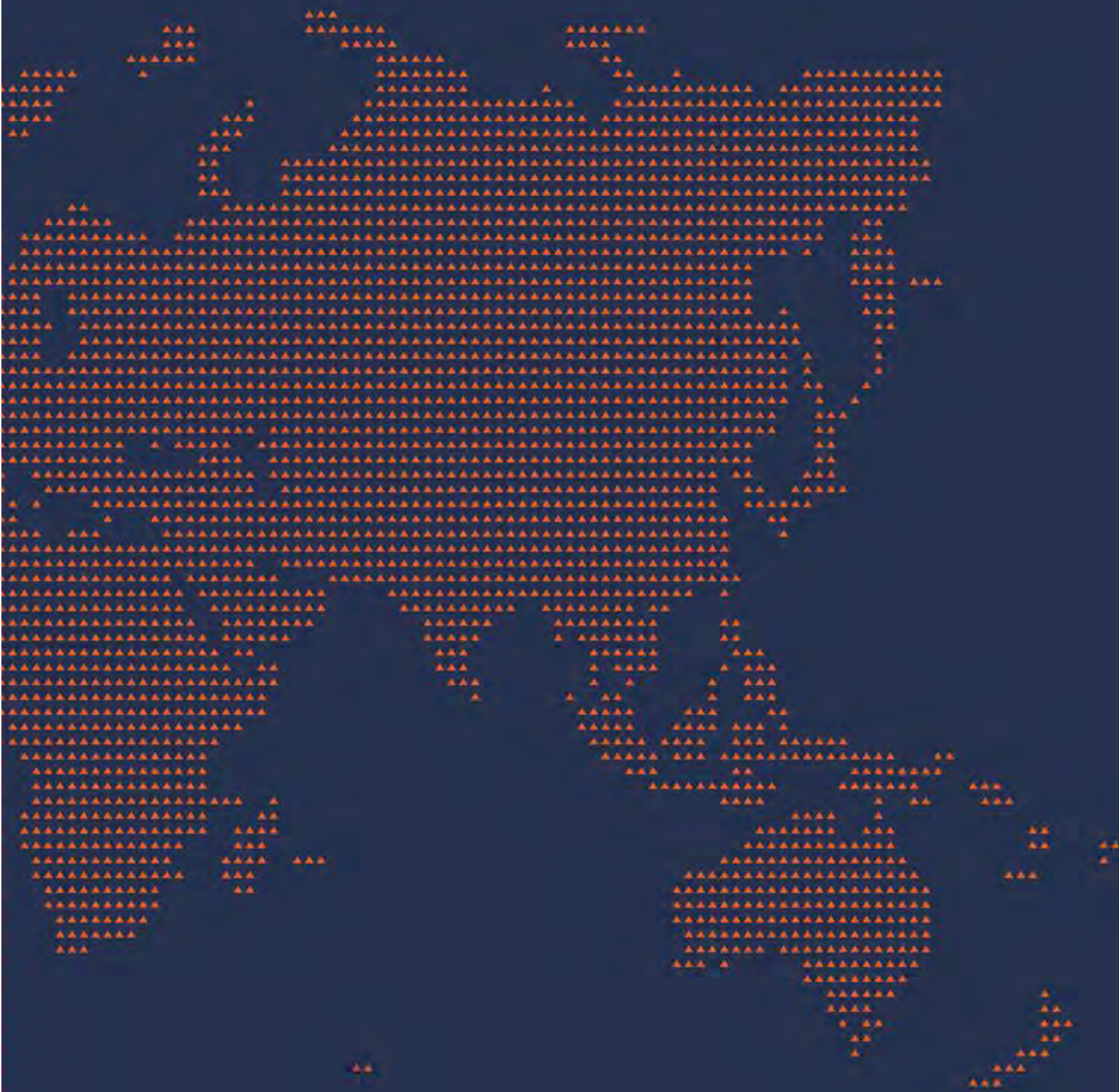
		carryover
		BUDGET
Overhead Distribution Projects		**$894,700**
S	2023 Carryovers	$ -
D	Highway 83, Dashwood (East End Only)	$ 142,000
SM	Industrial Rd, St. Mary's (OH Poles) - no transformers needed	$ 155,200
S	Griffith Rd - Scott St to Humber St	$ 215,000
S	Railway Ave - North of Walnut St.	$ 60,000
SF	Goderich St E - Upgrade to 3PH - no transformers needed	$ 65,000
N/A	Pole Line Design (Approximately 43 poles)	$ 22,500
N/A	GIS Support	$ 30,000
SM	Reinsulating	$ 85,000
N/A	GIS UN Conversion	$ 120,000
Underground Distribution Projects		**$925,500**
SM	2023 Carryovers	$ -
SF	West William St - URD Cable Removal - Install Secondary	$ 14,200
SF	Duke St (Track) - URD Cable Removal - Install Secondary	$ 30,100
SM	Station St - URD Cable Removal - Install Secondary	$ 16,000
S	Brunswick St - URD Cable Replacement (Looped)	$ 37,900
S	Waterloo/Albert ST - URD Cable Replacement	$ 62,000
S	Hibernia/Galt/McCann	$ 180,900
SM	Maxwell - From James to 39 Maxwell & Dunsford	$ 348,600
SM	Switchgears - 2 Replacements	$ 205,800
N/A	GIS Support	$ 30,000
Distribution Transformers		**$ 415,000**
Capital Additions - FHI Driven		**$ 312,573**
Capital Additions - Customer Driven		**$ 275,000**
New/Upgraded Services		**$ 195,000**
Distribution Meters - Residential/Commercial/Industrial Meters		**$ 400,000**
	2023 Carry Over	$0
	Services <50kW	$75,000
	Services >=50kW	$75,000
	CT's and PT's	$50,000
	SM 2.0 Deployment	$200,000
Distribution Automation - SCADA Enhancements		**$ 76,500**
Tools & Misc. Equipment		**$ 45,000**
	Tools - Operations	$ 40,000
	Misc Purchases	$ 5,000
Transformer Station		**$ 150,000**
	TS Capital (Primary Metering Unit Replacement)	$ 110,000
	TS Facilities (UPS)	$ 40,000
	DISTRIBUTION PLANT SUBTOTAL	**$3,689,273**
		BUDGET
Lands and Buildings		**$ 2,165,000**
	2023 Carry Over	$ -
	Administration Building Improvement 1st Floor Reno	$ 1,200,000
	Administration Building Improvement 2nd Floor Reno	$ 940,000
	Service Centre (Misc, Outdoor Rack)	$ 25,000
Vehicles and Trailers		**$ 450,000**
	Bucket Truck (Single) Replace Truck 6 (2005)	$ 450,000
Information Technology		
	Software Purchases	**$ 1,219,598**
	CIS Software Replacement	$ 285,250
	General Software	$ 59,348
	ERP Software Replacement	$ 875,000
	Hardware Purchases	**$ 193,069**
	Switches for Network Access Control	$ -
	Generic Hardware and Devices	$ 193,069
	GENERAL PLANT SUBTOTAL	**$4,027,667**
	DISTRIBUTION & GENERAL PLANTS TOTAL	**$7,716,940**

Attachment 12

Asset Condition Assessment

METSCO

MAKING IT POSSIBLE



Prepared For:

Festival Hydro Inc.

ASSET CONDITION ASSESSMENT REPORT 2018

Prepared by:

METSCO MAKING IT POSSIBLE

P-18-127

December 2018

Disclaimer

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Asset Condition Assessment Report 2018

Final Report

December 2018

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Executive Summary

This Asset Condition Assessment report is prepared for Festival Hydro's distribution assets. The report provides estimates of assets' conditions based on data provided by Festival Hydro in April and August 2018.

As Festival Hydro moves towards a risk-based asset management strategy to determine the optimal timing and scope of investments into asset renewal, an Asset Condition Assessment is prepared to determine the condition of the asset. A brief outline of implementing a risk-based asset management is documented in Section 2. The first step towards implementation of a risk-based asset management approach is to develop a yard stick, such as a Health Index, that could be employed to measure and benchmark the health and condition of in-service assets. A comprehensive methodology has been developed and documented in Section 3 of the report for assets targeted within the scope of this analysis. The methodology in this report has been updated to METSCO Energy Solutions Inc.'s Health Index Formulation to better reflect the accuracy of an asset's condition for risk management. By applying the methodology, asset's condition assessment is determined.

The Asset Condition Assessment is based on data compiled in April and August 2018 and covers the following classes of assets owned by Festival Hydro:

- Distribution poles
- Distribution transformers
- Overhead primary conductors
- Underground primary cables
- Overhead gang-operated switches
- Pad mounted Switchgears
- Vaults and manholes
- Distribution substation power transformers

In addition, comment sections were drafted highlighting the quantity and age for the following assets:

- Meter assets
- Switchgears for substation Welsh St. & Chalk St.
- Wright TS assets

For each asset group the Health Index is calculated with utility provided data. Assets are classified in one of five conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the Asset Condition Assessment are summarized in Figure 0.1.

Figure 0.1: Health Index Results

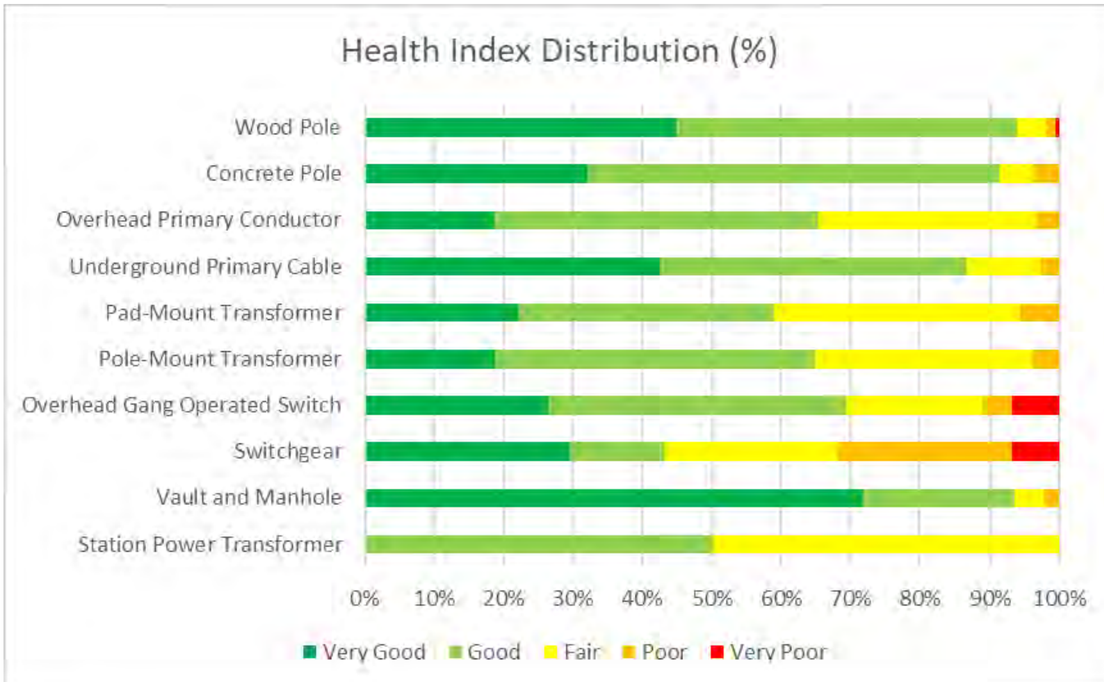

Table 0-1 presents the summary of the Health Index results. For each asset class the following details are given: the total population, average Health Index, average Data Availability Indicator (DAI) and the Health Index distribution. The Recommended Health Index Formulation is derived from METSCO's experience based on the Best Practice Health Index Formulations, the available data and the most important parameters that determine end of life. The Data Availability Indicator is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the Recommended Health Index Formulation. DAI of 100% for an asset indicates successful population of values for all condition parameters defined in the Recommended Health Index Formulation for the asset and is therefore a measure of the success in meeting its intentioned data collection. Though many assets are currently dependent on age only, it presents an opportunity for Festival Hydro to structure their data collection process moving forward. Additional data parameters will further reinforce Festival Hydro's ACA.

Majority of Festival Hydro's system is in Fair or better condition which suggests Festival Hydro's past renewal investments were effective in maintaining the system health. However, there are some assets that can benefit from an increase in asset renewal to reduce the risk of failure, decrease the cost of reactive failures and to reduce the amount of below Fair condition graded assets.

METSCO's strongest recommendation is that Festival Hydro begin collecting and keeping condition records consistent for all assets inspected rather than checking for a pass/fail criterion, which typically identifies assets in need of replacement. This will establish a stronger baseline of the asset health indices rather than being dependent on age. Additionally, METSCO has provided a recommended asset replacement plan for asset renewal solely based on the current ACA results calculated. The asset replacement plan is a baseline that provides the projected quantities of assets that would likely require replacement for the next short-term planning years 2019 to 2024 to improve the asset category's Health Index and to maintain the overall system health.

Table 0-1: Asset Condition Assessment Overall results

Asset Category	Pop.	Health Index Distribution (%)					Avg. Health Index	Avg. DAI
		Very Good	Good	Fair	Poor	Very Poor		
Wood Pole	2396	45%	49%	4%	1%	1%	83%	88%
Concrete Pole	3675	32%	59%	5%	4%	0%	80%	Age only
Overhead Primary Conductor (m)	400,643	19%	47%	31%	3%	0%	74%	Age only
Underground Primary Cable (m)	175,283	43%	44%	10%	3%	0%	78%	N/A
Pad-Mount Transformer	988	22%	37%	35%	6%	0%	78%	Age only
Pole-Mount Transformer	989	19%	46%	31%	4%	0%	83%	Age only
Overhead Gang Operated Switch	117	26%	43%	20%	4%	7%	69%	Age only
Switchgear	44	30%	14%	25%	25%	7%	63%	Age only
Vault and Manhole	46*	72%	22%	4%	2%	0%	87%	100%
Station Power Transformer	4	0%	50%	50%	0%	0%	74%	92%

** The count is provided from a third-party report. Does not represent actual quantity in-service.*

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1 Introduction

This report summarizes the results of an Asset Condition Assessment (ACA) study carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of Festival Hydro. The main objectives are to generate Health Indices with current condition data of in-service assets employed on the electricity distribution plan and recommend replacement plans.

The ACA methodology is applied to different categories of assets that are employed on Festival Hydro's distribution system. Adoption of the ACA methodology requires periodic asset inspections and recording of asset condition to identify those most at risk. Additionally, computing the Health Index for distribution assets requires identifying end-of-life criteria for various components associated with each asset type. Each criterion represents a factor that is influential in determining the component's condition relative to its potential failure. These components and tests shown in the tables are weighted based on their importance in determining the assets' end-of-life.

The assets covered in the report include the following assets:

- Distribution poles
- Distribution transformers
- Overhead primary conductors
- Underground primary cables
- Overhead gang-operated switches
- Pad mounted Switchgears
- Distribution substations

The information contained within this report is compiled based on data available in April and August 2018. The report is organized into four sections including this introductory section:

- Section 2 outlines the strategic asset management plan, summarizing standards PAS-55 and ISO 55000/55001/55002, an overview of the METSCO methodology and the ACA process;
- Section 3 provides the Condition Assessment methodology framework and assessment for the asset's age, condition and data collection;
- Section 4 summarizes our recommendations for Festival Hydro on data collection improvements for improving the Health Index results;
- Section 5 summarizes a recommended strategy plan for Festival Hydro for future investment planning.

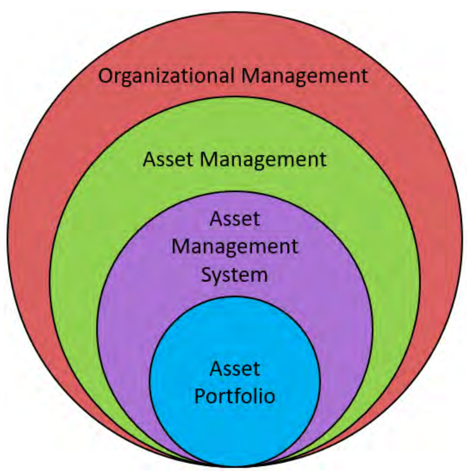
2 Strategic Asset Management Plan

2.1 Industry Standard for Asset Management Planning

The Industry Standard for Asset Management Planning is outlined in ISO 5500X. Asset Management (AM) is generally applied to one of three groups of entities: those looking to establish and set up an asset management system, those looking to realize more value from an asset base, and those looking to review an asset management system already in place for avenues of improvement. In this way, ISO 5500X should always be applied in the scope of the organization; relating to its purpose, operating context, and financial constraints. Stakeholders should be of primary concern when applying or analysing any new or updated AM framework.[1]

An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (i.e. public safety). According to ISO5500X, the hierarchy of an AM framework is as follows: an asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. Around the asset portfolio the AM system operates and is the set of interacting elements to establish policy, objectives, and the processes to achieve those objectives. The AM system is encompassed by the AM practices, which are executed as the coordinated activity of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.[1]

Figure 2.1 Relationship between key Asset Management terms[1]



Asset management is fundamentally grounded as a risk-based approach. The overarching goal of an AM process it to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through asset management operations and procedures. The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among

[1] ISO 55000 – Asset management – Overview, principles and terminology

assets, better informed investment decisions, demonstrated compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

Asset management processes are ideally integrated throughout an entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its own on-hand resources, whether it be via technical experts, those operating and maintaining the assets, or those with an understanding of the financial operations and constraints on the organization as a whole. Usually the AM implementing principles are documented within a Strategic Asset Management Plan (SAMP). The SAMP should be used as a guide for the organization to apply its asset management principles and practices for its specific-use case. Distribution of the SAMP should be open within an organization and updated on regular basis in order to best quantify the most current and comprehensive asset management practices being implemented within the organization. Just as the asset base performance is subject to in-depth review, the asset management process and system should be reviewed with the same rigor.[1]

Well executed AM hinges on the ability for an organization to classify its asset via comprehensive and extensive data and data collection procedures. This includes but is not limited to: the collection and storage of technical specifications, historical asset performance, projected asset behaviour and degradation, configuration of an asset or asset-group within the system, the operational relation of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio within an organization will allow for fluid reorganization or changes in management processes to realize tangible benefits to the organization. This is largely due to AM being a fundamentally risk-based approach, which lends it to be a sound framework for creating financial plans driven by evidence-based support. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include: better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 5500X states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented.[2]

Finally, asset management should be regarded to as a fluid process. Adopting a framework and idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any asset management system is to continually improve and realize benefit within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration of into all aspects of an

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

An Asset Condition Assessment (ACA) represents the first step in fully integrating the AM framework outlined by ISO 55000. By evaluating the current set of available data related to the condition of in-service assets within an organization's asset portfolio, condition scores for each asset are determined. The level of degradation of an asset, knowledge of its configuration within the system, and its corresponding likelihood of failure feed directly into a risk-based assessment. Efforts of an ACA strive to collect, consolidate, and present the results framed by the current organizational AM framework for the purposes of properly quantifying and managing the risks of its asset portfolio. An ACA should provide insights into the current state of an organizations asset base, the risks associated with the degradation of portions of the assets in the system, how this degradation can be better managed within the current AM framework, and how to best make use of these results to extract maximum value from the asset portfolio going forward.

2.2 Overview of METSCO METHODOLOGY

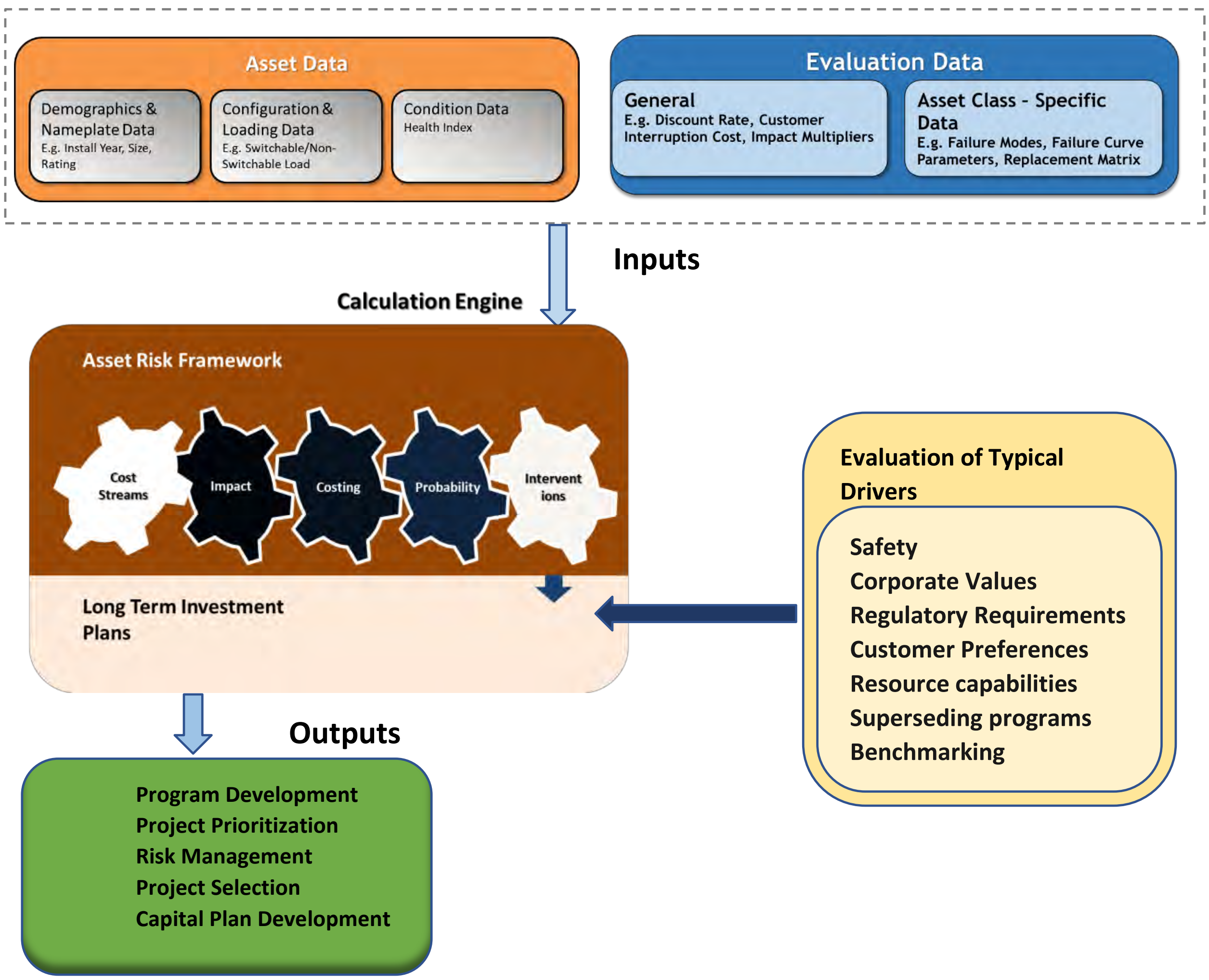
2.2.1 Overall Asset Management Strategy

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Most of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal investment. On the other hand, investments not made on time when warranted by the system needs raise the risk of missing performance targets and would not result in optimized investment. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

METSCO is a proponent of a Risk-Based Asset Management Strategy, which determines the risk of asset failure based on the condition of the asset, which is commonly measured with the "Asset Health Indices" and computes the valuation of the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

The overarching objective is to develop a prioritized capital and preventative maintenance investment plans, which are implemented over periods of ten to twenty-five years and optimize system performance. Corporate objectives and performance requirements are incorporated in the model by placing appropriate weights and costs on project drivers as shown in Figure 2.3.

Figure 2.3: Model to Identify Assets with Highest Risks



METSCO's overall asset management approach includes executing and assessment within the 5 frameworks as presented in Figure 2.4. Under the asset Health Index (HI) framework development, an Asset Condition Assessment (ACA) is performed. ACA is used to produce the HI, which is a quantified condition score of the asset. HI score is ultimately calculated using asset age and inspection data. With this technique, condition-based failure probability can be determined. Different assets have different failure curves that are calibrated using their failure data. In risk calculations, failure probability is used to determine the likelihood of failure of an asset of a given age in a given year. Failure mode and impact framework development calculates the consequence cost values for various failure modes considering customer impacts, collateral damage impact, environmental impact, etc. Once the probability and impact of asset failure have been determined, the risk cost can be calculated, along with the life-cycle costs of the asset. Assets will be recommended for optimal replacement when an optimal balance is achieved between capital spending and risk mitigated.

For this report, the Asset Health Index Framework Development (i.e. the first framework) is only developed. The remaining frameworks are identified to outline for Festival Hydro the future steps that can be taken to further enhance their Asset Management practices. However, the Asset Health Index Framework is the first step needed to be taken and is the foundation for the remaining identified four frameworks.

Figure 2.4: Overall AM approach

2.2.2 Asset Condition Assessment Process

The major steps in the ACA are briefly discussed below:

1. Identify Asset Classes: Identify asset classes to be considered in the asset condition assessment study

   Typical asset classes in the distribution system include:

   - Station Transformers
   - Station Circuit Breakers
   - Station Batteries
   - Capacitors

- Controls and Protective Relays
- Overhead Primary Conductors
- Underground Primary Conductors
- Distribution Transformers
- Switches
- Poles

2. Data Analysis:
   - Collection of asset related data such as GIS records, asset demographics, inspection/testing records, etc.
   - Validate the accuracy of data, e.g. check for data discrepancies between files
   - Develop a "Recommended Health Index Formulation" (RHIF) for each asset based on the available data, published best practice information and expert assessment of the data parameters which are reasonably obtained and are most indicative of asset end of life.
   - Identify additional asset data needed to determine and evaluate asset condition and assess the potential of collecting additional useful asset condition information to improve accuracy of the asset condition assessment results.
   - Make recommendation on collecting additional data that is reasonably available. [The methods to obtain additional data typically include inspection, testing, sampling, collection of paper records, field work to collect asset data, adopting advanced technology to record inspection/testing data, etc.]

3. Collect additional condition information specific to each asset class.

4. Calculate Data Availability Indicator (DAI)

   DAI is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the RHIF. DAI is calculated as a ratio of sum of weighted condition parameters score of available condition parameters to sum of weighted condition parameters score from the recommended HI formulation.

$$DAI = \left(\frac{\sum_{i=1}^{N} Weight_i * CPAF_i}{\sum_{i=1}^{N} Weight_i} \right) x\ 100$$

   Where *i* corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation, and *CPAF* is the Condition Parameter Availability Factor which is equal to 1 if the condition parameter data is available for the asset otherwise equal to 0.

   DAI of 100% for an asset indicates successful population of values for all condition parameters defined in the Recommended Health Index Formulation for the asset and is therefore a measure of the success in meeting its intentioned data collection. Typically, the targets for

DAI are less than 100% for "sampled" assets such as cables and wood poles or where the costs to collect additional data are not warranted such as for low risk assets.

In addition, there is a data set representing the "Best Practice Health Index Formulation", which an asset owner may be moving towards and in this case the recommendation for process improvements may include the effort to be taken to collect additional condition parameters defined in the Best Practice Health Index Formulation for the entire population of assets which is expected to increase the accuracy of ACA results.

5. Asset Condition Assessment

A Health Index (HI) is an indicator of asset remaining life given as a percentage. A new asset should have a HI of 100% and an asset in very poor health should have a HI below 30%. Table 2-1 presents the HI ranges and the corresponding asset condition.

Table 2-1: Asset Condition based on Health Index

Health Index	Condition	Description	Requirements
[85–100]	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
[70–85)	Good	Significant deterioration of some components	Normal maintenance
[50–70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on criticality
[30–50)	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate considering risk and consequences of failure
[0–30)	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk; replace or refurbish based on assessment

To determine the HI for an asset, formulations are developed based on conditions that lead to asset end of life. A weight is assigned to each condition to indicate the amount of influence the condition has on the overall asset health. When presented with a HI formulation such as:

Table 2-2: Health Index Calculation Example

#	Condition Criteria	Weight	Condition Grade	Factors	Maximum Score
1	Condition example 1	4	A,B,C,D,E	4,3,2,1,0	16
2	Condition example 2	6	A,C,E	4,2,0	24
3	Condition example 3	6	A,B,C,D,E	4,3,2,1,0	24
	MAX SCORE				**64**

Each condition is ranked from A to E and each rank corresponds to a numerical grade:

A – 4 Best Condition
B – 3 Normal Wear
C – 2 Requires Remediation
D – 1 Rapidly Deteriorating
E – 0 Beyond Repair

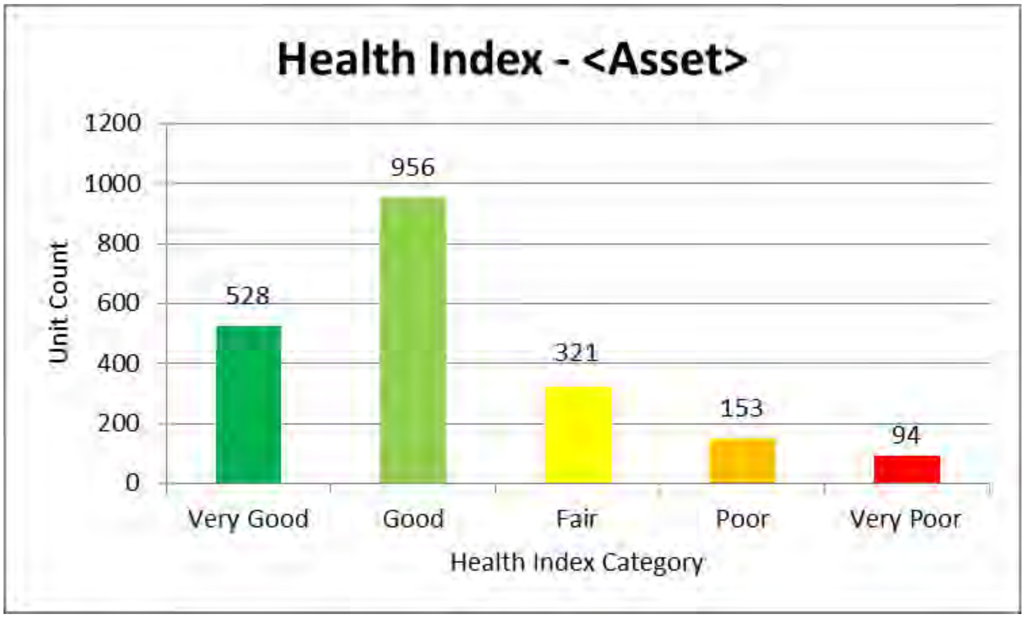
The Health Index is then calculated as follows:

$$HI = \left(\frac{\sum_{i=1}^{N} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100$$

Where *i* corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation and the *HI* is a percentage representing the remaining life of the asset.

Figure 2.5 shows the example graph representation of HI conditions for an asset class categorizing assets into Very Good to Very Poor condition.

Figure 2.5: Asset Health Index Graph-Example



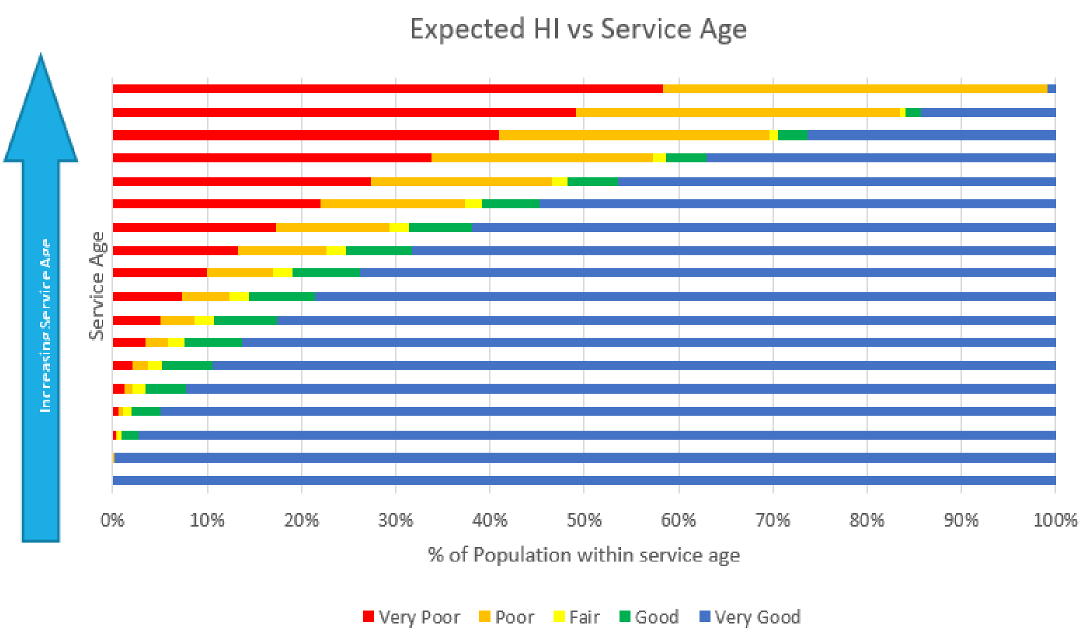
6. Demographic Assessment

A useful cross-reference to a HI is a representation of asset demographics. Assets are charted based on age from installation date, and other pertinent demographics such as material or manufacturer/type etc. Since many people still consider age when making replacement plans, it is important to document any significant variations from the age-base results and the condition-based HI. As an example, cables are known to have different life expectancies based on the technology available at the time of installation or in other cases equipment of a certain manufacture may be known to be reaching end of life and failing at a higher than predicted rate. Figure 2.6 represents a typical demographic chart to represent the asset age data.

Figure 2.6: A Typical Demographic Chart

Figure 2.7 presents the example expected relation between the HI condition and the service age. It is expected that the HI conditions should gradually change from Very Good to Very Poor as the service age of an asset increases.

Figure 2.7: Expected HI Vs Service Age Trend-Example



7. Recommendations: The last stage of the ACA process provides with recommendations to the organization on data collection process improvements that are expected to increase the validity of HI results.

3 Health Indices

3.1 Distribution Assets

3.1.1 Wood Pole

3.1.1.1 Condition Assessment Methodology

Wood being a natural material has degradation processes that are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather.

The Health Index for wood poles is calculated by considering a combination of service age and remaining strength of poles. Table 3-1 summarizes the methodology to combine these criteria into an overall Health Index for wood poles.

Table 3-1: Wood Pole Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Remaining Strength	8	A,B,C,D,E	4,3,2,1,0	32
				MAX SCORE	**44**

Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter. Table 3-2 is used to translate age into a condition rating.

Table 3-2: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 55 years
E	Over 55 years

Table 3-3 is used to translate remaining strength of the pole into a condition rating.

Table 3-3: Criteria for Remaining Strength

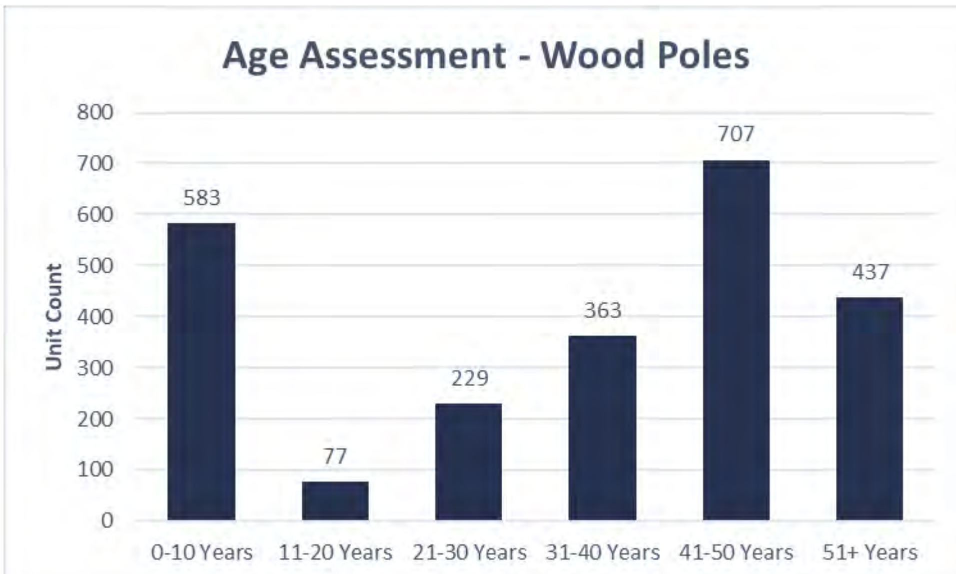
Condition Rating	Corresponding Condition
A	91% to 100%
B	81% to 90%
C	71% to 80%
D	61% to 70%
E	Less than 60%

3.1.1.2 Results of Analysis

Age Assessment

Festival Hydro owns 2396 wood poles within its service territory. Through discussions with Festival Hydro, it is determined wood poles with an unknown age receive a rating of “new” with the assumption of being 15 years or younger. However, it is recommended to review this assumption to confirm the viability. Figure 3.1 presents the age distribution for wood poles in-service.

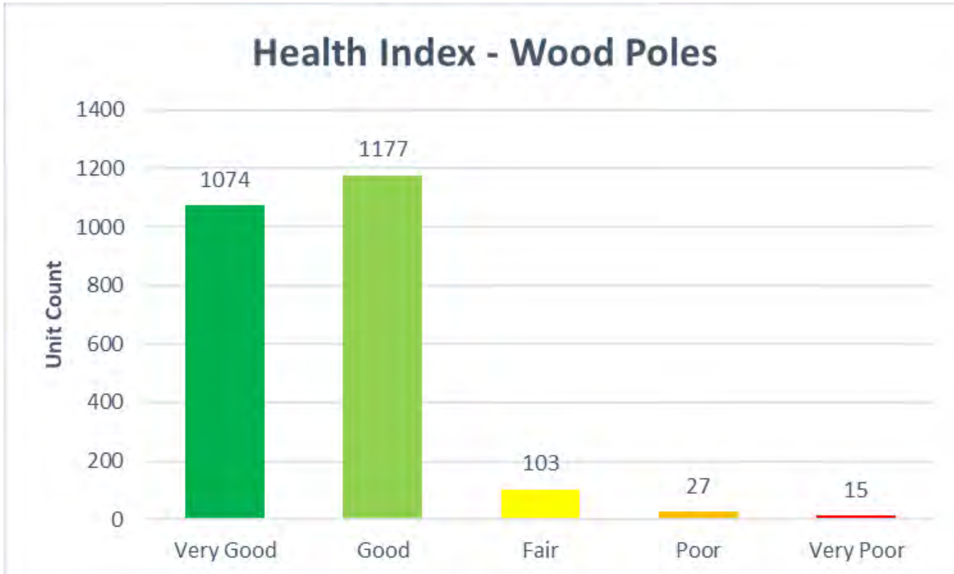
Figure 3.1: Wood Pole Age Demographic



Condition Assessment

Festival Hydro’s pole test data and demographics were used to calculate the Health Index based on the criteria provided in Table 3-1. Festival Hydro also visually inspects their pole population for critical poles but does not maintain historical records suitable for analysis. Festival Hydro uses two types of tests to determine the remaining strength of wood poles – the sound and bore method and the Polux testing method. The Polux test assumes that the pole is fully loaded, typically not the case for most poles, resulting in more conservative values calculated. Festival Hydro obtains values from the sound and bore test for older poles mostly and uses the Polux test values as a reinforcement in asset condition. Polux test values are used if there is no sound and bore values available. Additionally, newer wood poles are only tested using the Polux method, whereas older poles receive both tests. New wood poles represent a small percentage of the total population of the wood poles. The overall Health Index distribution is presented in Figure 3.2.

Figure 3.2: Wood Pole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The average DAI for pole data is 88%. Section 4.0 provides additional recommendations for data collection for HI improvement.

3.1.2 Concrete Pole

3.1.2.1 Condition Assessment Methodology

The Health Index for concrete poles is calculated by considering only the service age. Table 3-4 summarizes the methodology to combine this criterion into an overall Health Index for concrete poles.

Table 3-4: Concrete Pole Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
				MAX SCORE	**4**

Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter. Table 3-5 is used to translate age into a condition rating.

Table 3-5: Criteria for Service Age

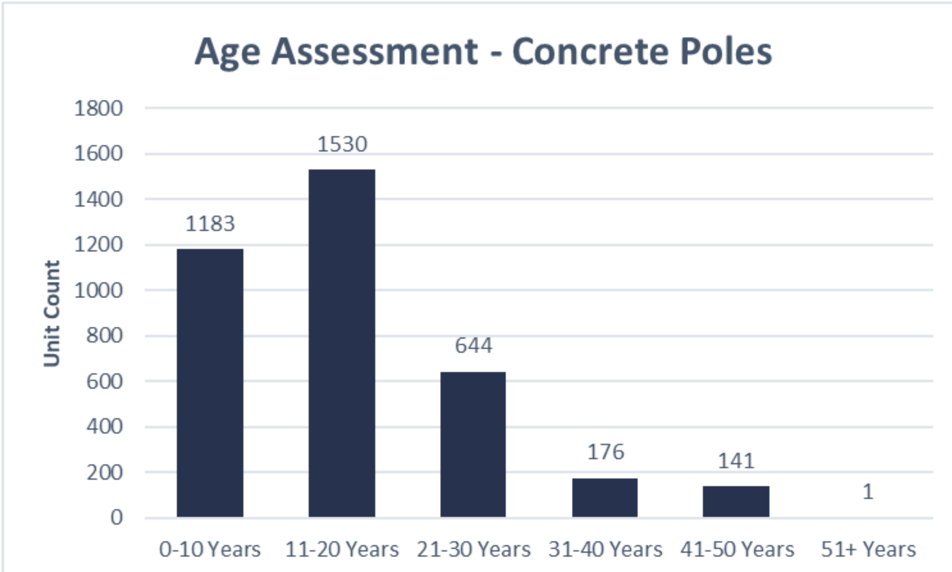
Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

3.1.2.2 Results of Analysis

Age Assessment

Festival Hydro owns approximately 3675 concrete poles within its service territory. Figure 3.3 presents the age distribution. Through discussions with Festival Hydro, it is determined concrete poles with an unknown age receive a rating of “new” with the assumption of being 25 years or younger. However, it is recommended to review this assumption to confirm the viability.

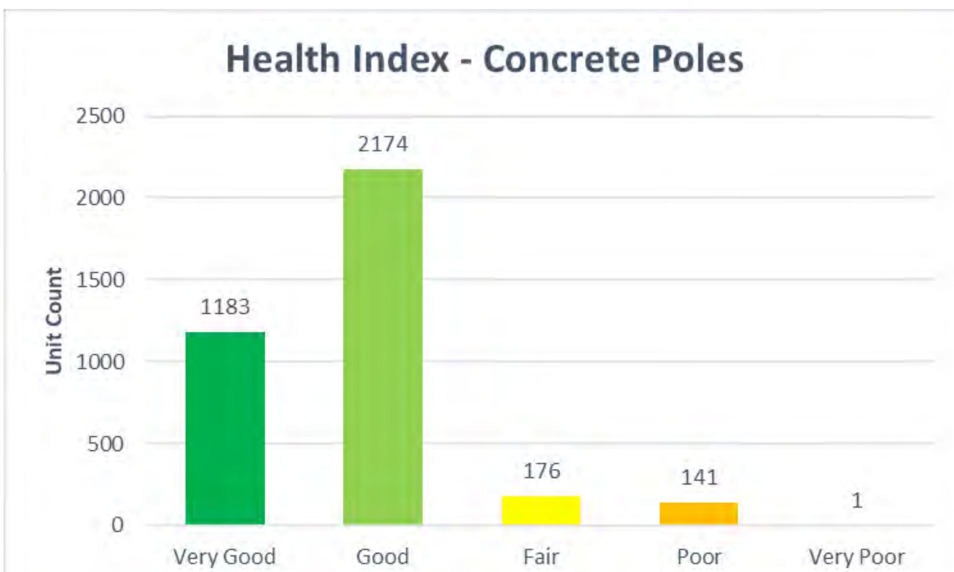
Figure 3.3: Concrete Pole Age Demographic



Condition Assessment

Festival Hydro's age data was used to calculate the Health Index. The Health Index values were determined for the known age data set whereas those with an unknown age were given a rating as "new" as per discussion with Festival Hydro. The overall Health Index distribution is presented in Figure 3.4.

Figure 3.4: Concrete Pole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. Since the only parameter used for calculating the HI is age, a DAI is not provided. However, age is known for 75% of concrete poles in-service. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.3 Overhead Primary Conductor

3.1.3.1 Condition Assessment Methodology

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. As a general rule, conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small gauge, solid strand copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

The Health Index for overhead conductors for Festival Hydro is calculated by considering only service age presented in Table 3-6.

Table 3-6: Overhead Primary Conductor Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
				MAX SCORE	**4**

The service age provides a reasonably good measure of the remaining strength of overhead conductor with the lack of visual inspection for conductor defects. Table 3-7 is used to translate age into a condition rating.

Table 3-7: Criteria for Service Age

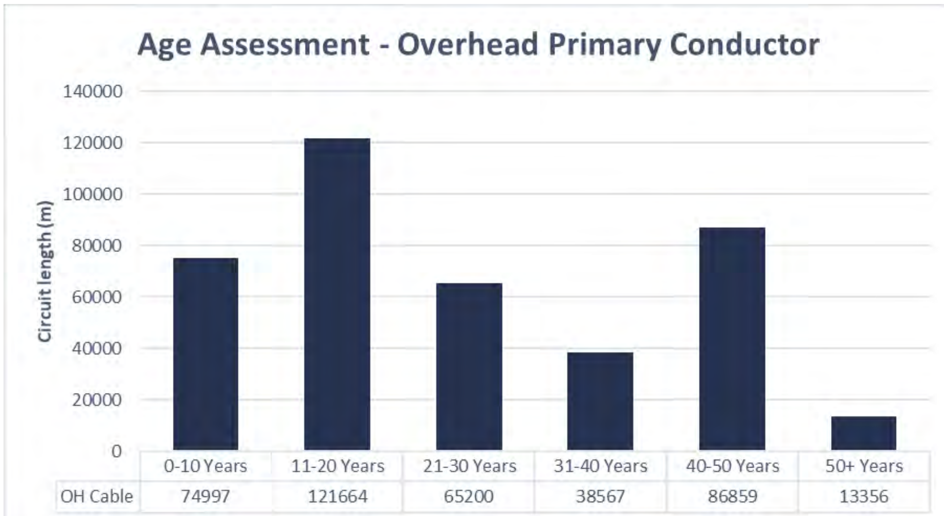
Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	71 years or older

3.1.3.2 Results of Analysis

Age Assessment

Festival Hydro owns approximately 400.6km of overhead primary conductor within its service territory. Figure 3.5 presents the age distribution as provided.

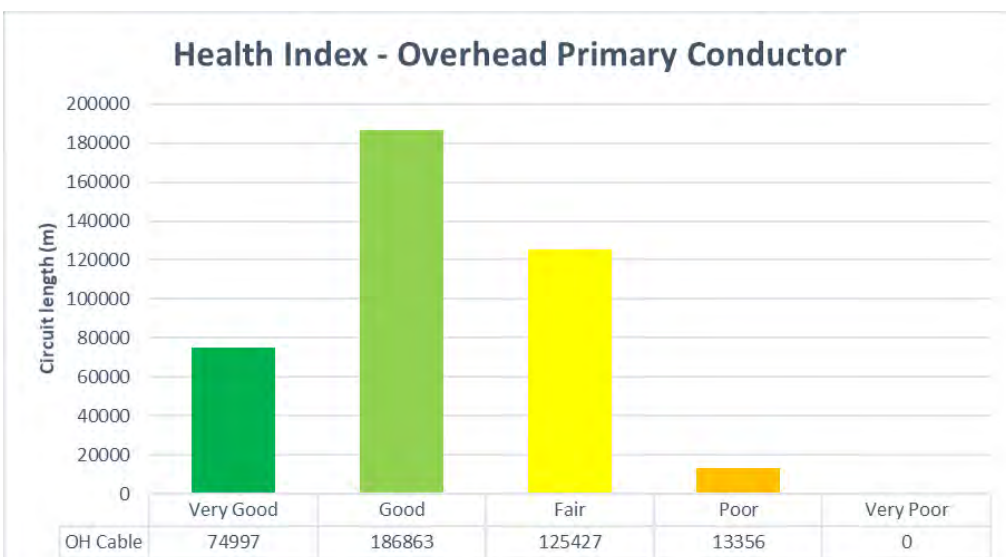
Figure 3.5: Overhead Primary Conductor Age Demographic



Condition Assessment

Festival Hydro's 2018 overhead primary conductor data was used to calculate the Health Index based on the criteria provided in Table 3-6. The overall Health Index distribution is presented in Figure 3.6.

Figure 3.6: Overhead Primary Conductor Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. Since the only parameter used for calculating the HI is age, a DAI is not provided. However, age is known for 100% of overhead primary conductor's in-service. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.4 Underground Primary Cable

3.1.4.1 Condition Assessment Methodology

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although several test techniques, such as partial discharge (PD) and water tree diagnostic testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. However, a sampling methodology can be executed to determine a general condition of the asset. A common approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

The Health Index for underground primary cable is calculated by considering the service age. Table 3-8 summarizes the methodology to generate a Health Index.

Table 3-8: Underground Primary Cable Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
				MAX SCORE	**4**

The service age provides a reasonably good measure of the remaining strength of underground primary cables. Table 3-9 is used to translate age into a condition rating.

Table 3-9: Criteria for Service Age

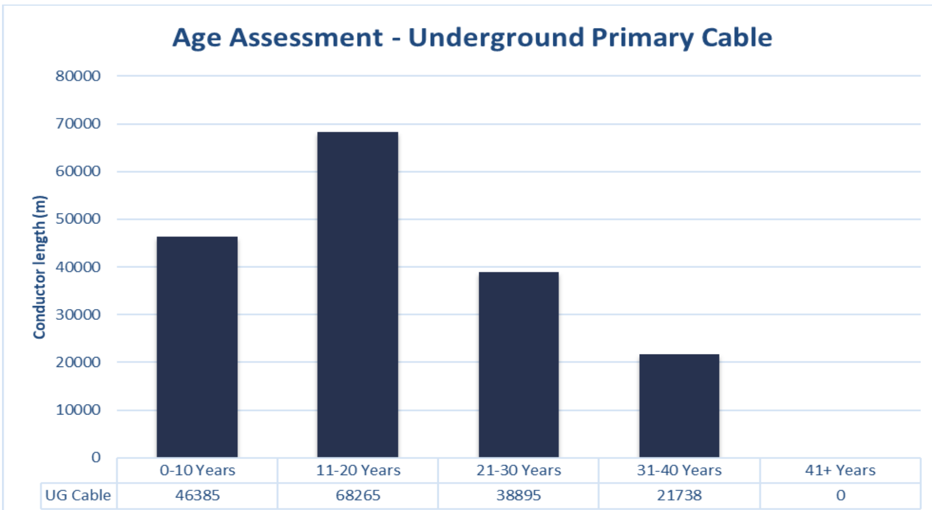
Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	46 years or older

3.1.4.2 Results of Analysis

Age Assessment

Festival Hydro owns approximately 175.2km of underground primary cable within its service territory. Figure 3.7 presents the age distribution. Cable lengths with an unknown age (>1.5%) are redistributed into the asset's age demographic.

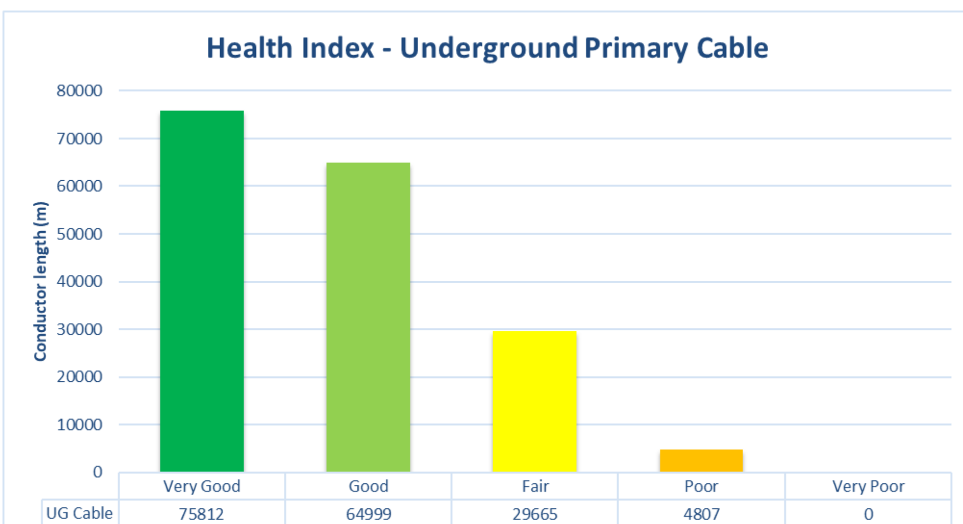
Figure 3.7: Underground Primary Cable Age Demographic



Condition Assessment

Festival Hydro's 2018 underground primary cable data was used to calculate the Health Index based on the criteria provided in Table 3-8. The overall Health Index distribution is presented in Figure 3.8.

Figure 3.8: Underground Primary Cable Health Index Demographic



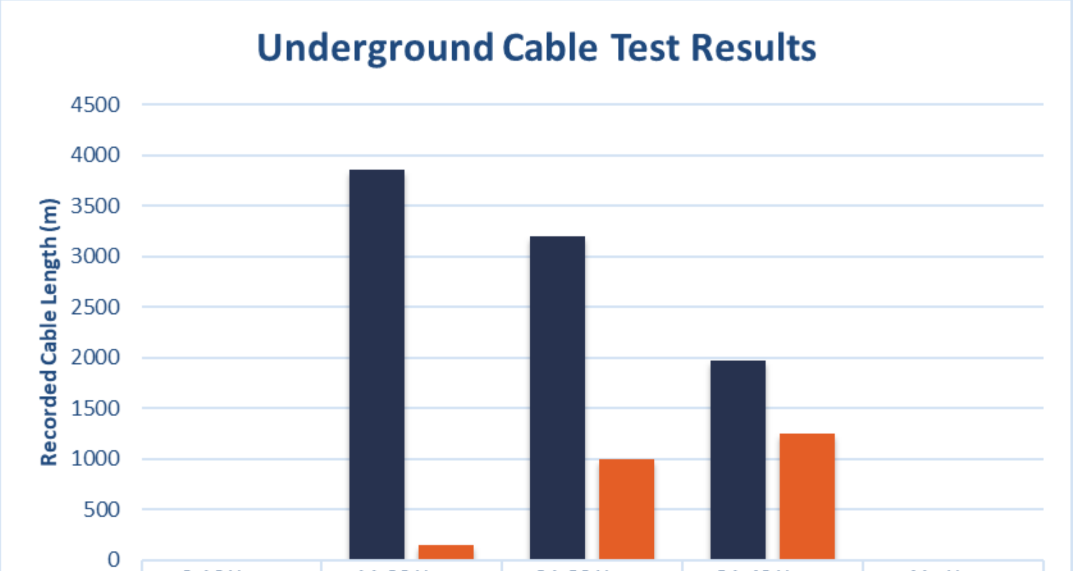
Festival Hydro hired a third-party contractor to complete an assessment on a subset of Festival Hydro's underground primary cable through non-destructive testing. The test utilizes National Research Council Canada (NRC)'s DC Polarization/Depolarization Current Measurement system. Information regarding the test procedure employed through the third-party contractor is found in the contractor's report provided to Festival Hydro.

The results of the cable tests are qualified as Good, Fair, and Poor. The following section is an excerpt from the report quantifying the failure probability of the cable:

> *Good condition: Failure probability due to water treeing is low but could increase and result in insulation failure if voltage transients due to switching operation or lightning surges are not properly controlled. Cable could be repaired and returned to service after failure.*
>
> *Fair condition: Failure probability due to water treeing is moderate and could increase and result in insulation failure if voltage transients due to switching operation or lightning surges ae not properly controlled. Cable should be re-tested every 3-5 years to keep track of the on-going water tree deterioration.*
>
> *Poor condition: Failure probability due to water treeing is high and any repair to the cable would be short lived. The cables in this category should be scheduled for early replacement.*

66 cable segments were tested ranging in age from 17 years to 40 years. The 66 cable segments averaged a recorded length of 176 meters/segment or totaled to a recorded length of 11,431 meters (~6.5% of the total underground cable in-service at Festival Hydro). However, this represents about 20% of the underground primary cables that are older than 20 years. The tested cables represent a small portion of the total population. However, the results found within the report can be visualized with age groups to identify a trend. Figure 3.9 presents the total cable lengths tested to be in Good or Fair condition categorized by age groups of 10 years. No cable tested was in Poor condition. It is evident that as the cable increases in age, there is an increase of cables moving from Good to Fair condition. Should Festival Hydro do additional testing of cables, specifically those that are the oldest in the system, the trend can be readjusted to reflect the additional data points collected. It is important to note, Festival Hydro has not noted any failures for underground primary cables to date.

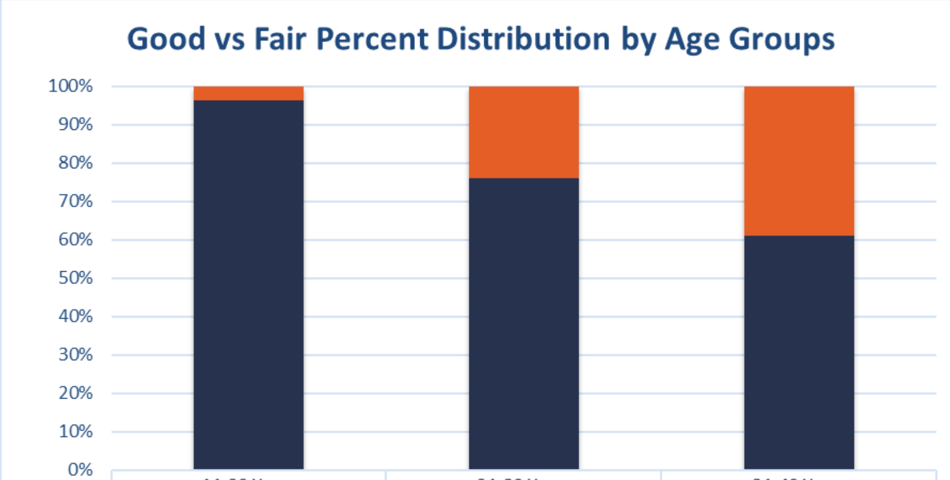
Figure 3.9: Underground Primary Cable Test Results



	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41+ Years
Good	0	3864	3200	1968	0
Fair	0	145	1000	1254	0

The above figure can be reconfigured to present the percent distribution of cables in Good versus Fair condition by age groups. Figure 3.10 presents this visualization. The graph is a snapshot representation of what Festival Hydro's in-service underground cable could be. In addition, it is likely that underground cables past 40 years of age would deteriorate quicker. Since there is currently no underground cable segment above the age of 40, a sampling test could not be performed. No viable assumptions can be made as to what percentage of underground cables will move from Fair to Poor.

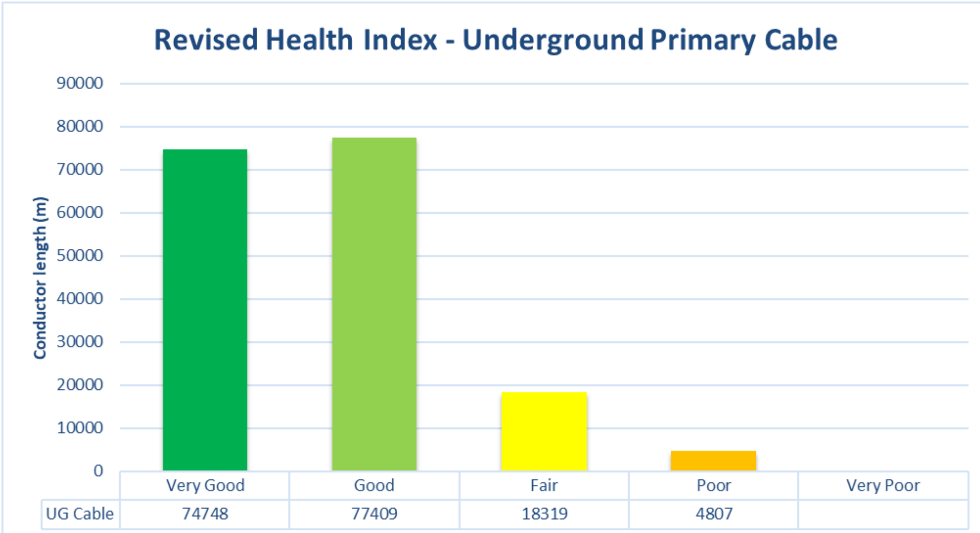
Figure 3.10: Percent Distribution of Underground Primary Cables Tested by Age Group



	11-20 Years	21-30 Years	31-40 Years
Fair	4%	24%	39%
Good	96%	76%	61%

The Health Index demographic can be modified to incorporate the results of the cable test reports as well as the percent distribution from Figure 3.10. Since the cable test results do not present the unique specific cable identifier, the weight of the cable test result needs to be assumed an equal weighting to the age parameter within the Health Index formulation. The revised Health Index results is found in Figure 3.11. A slight increase is seen in the amount of cables identified as Good, which previously have been identified as Fair. This implies Festival Hydro's underground cables are in better condition. However, Festival Hydro should continue to monitor and test additional underground primary cables to increase the tested population size. Moving forward, Festival Hydro should record the tested cable results into the asset registry to identify those cables easily and to place a higher significance on the cable test versus cable age.

Figure 3.11: Revised Underground Primary Cable Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. Since the only parameter used for calculating the HI is age, a DAI is not provided. However, age is known for 98.5% of underground primary cables in-service. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.5 Distribution Transformer

Two types of distribution transformers are assessed within this report:

- Pole mounted transformer
- Pad mounted transformer

3.1.5.1 Condition Assessment Methodology

Typically, utilities replace distribution transformers as part of overhead or underground rebuild projects or when they are assessed as having a high risk of failure. Furthermore, pole-mount transformers are replaced when a pole requires replacement or has failed. Typically, these pole-mount transformers are older and are found on older poles that will require replacement within the short-term. Apart from painting the tanks, replacing a damaged bushing or repairing a leaky gasket, very little preventative maintenance or testing is carried out on distribution transformers. Festival Hydro continues to perform regular visual inspections to manage the system risk and reliability. The Health Index for distribution transformers is calculated by considering only service age. Table 3-10 summarizes the methodology to generate the Health Index.

Table 3-10: Distribution Transformer Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
				MAX SCORE	**4**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter. Table 3-11 presents the service age condition rating.

Table 3-11: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

3.1.5.2 Results of Analysis

Age Assessment

Festival Hydro owns 1977 distribution transformers in-service of which 989 are pole mount and 988 are pad mount transformers. Figure 3.12 and Figure 3.13 present the age distribution by transformer types. Through discussions with Festival Hydro, it is determined transformers with an unknown age are at least 20 years old.

Figure 3.12: Pole Mount Transformer Age Demographic

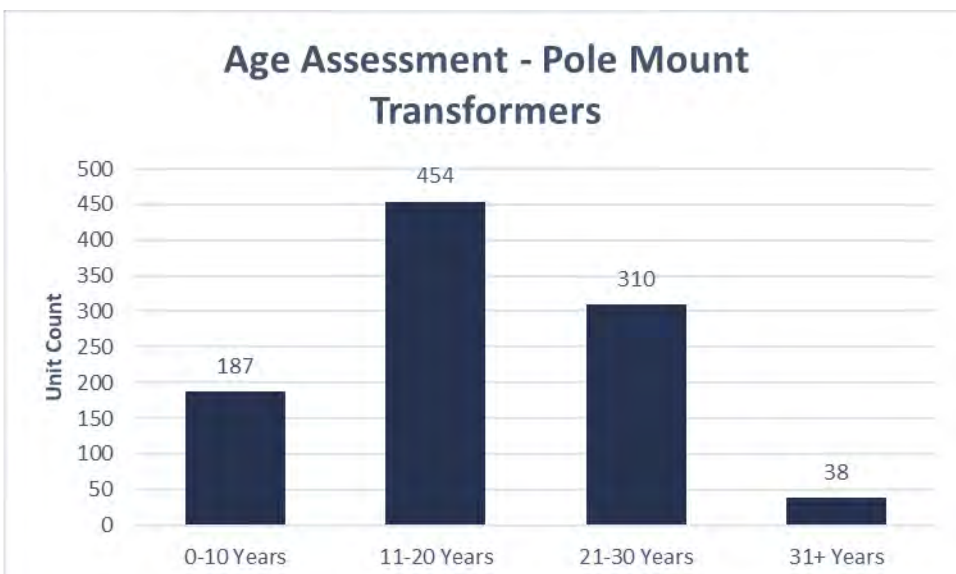
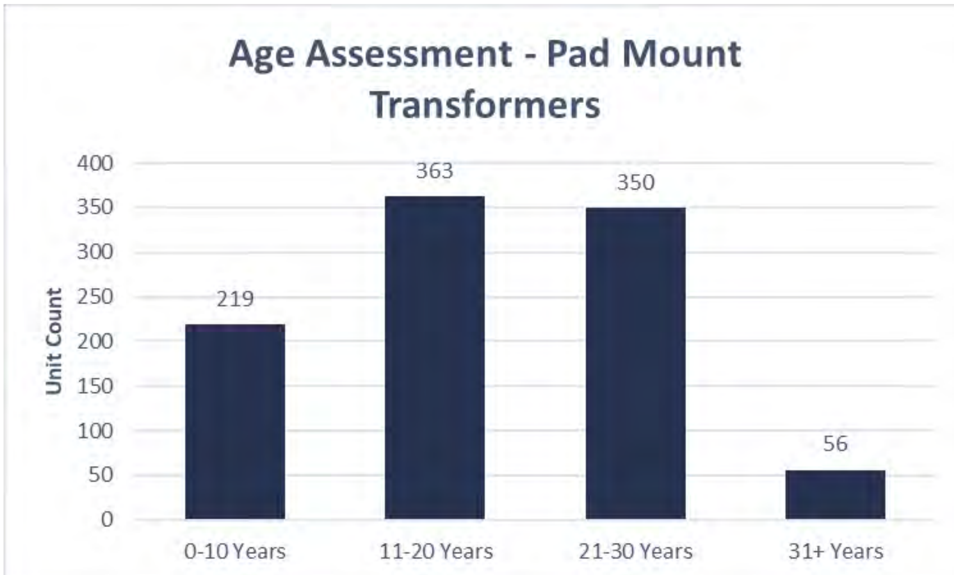


Figure 3.13: Pad Mount Transformer Age Demographic



Condition Assessment

Festival Hydro's 2018 transformer data was used to calculate the Health Index based on service age. The overall Health Index distribution is presented in Figure 3.14 to Figure 3.15 for each transformer type. Visual records for Festival Hydro's transformers are limited to a very small population. Transformers with extensive rust, oil leak present or other visible damage identified through Festival Hydro's bi-annual transformer inspections are replaced as soon as possible.

Figure 3.14: Pole Mount Transformer Health Index Demographic

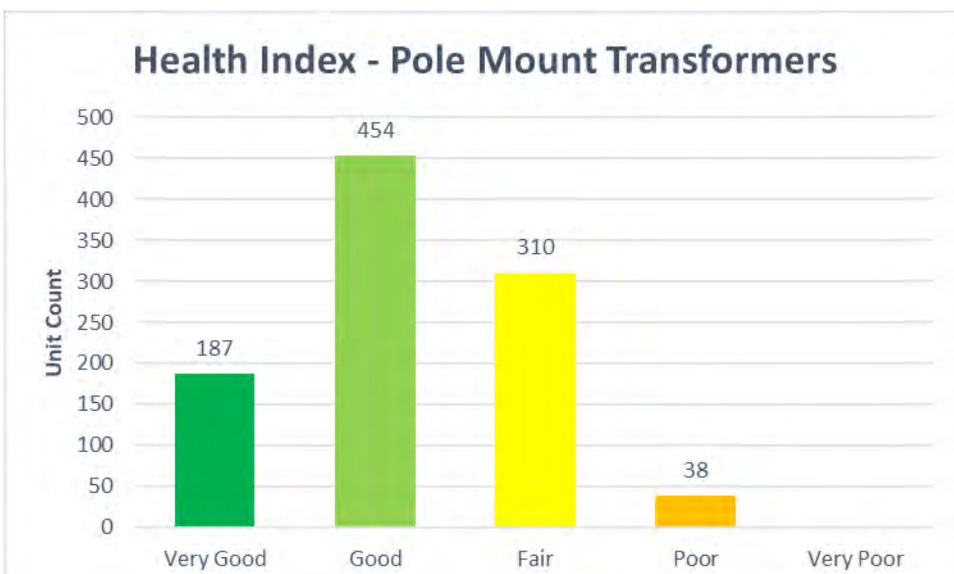
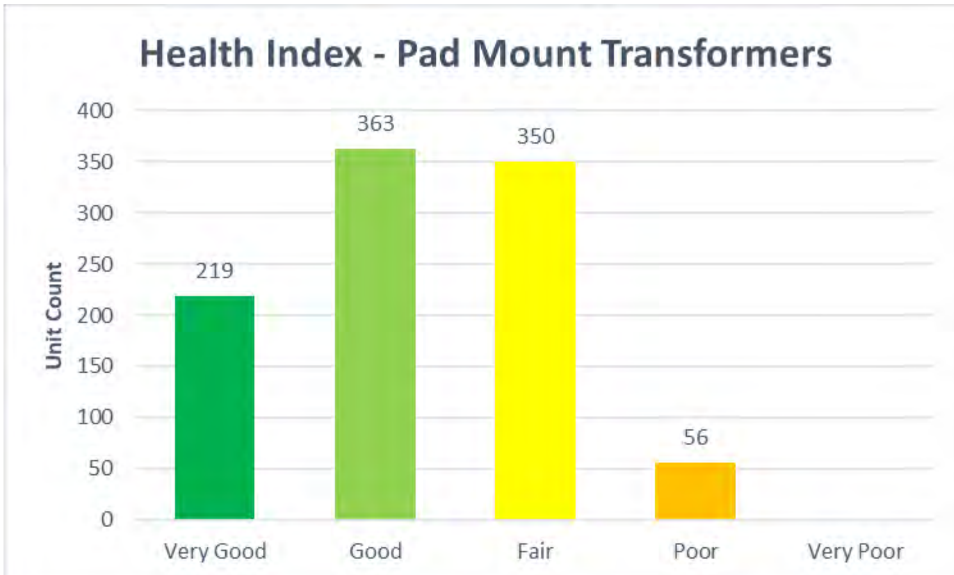


Figure 3.15: Pad Mount Transformer Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. Since the only parameter used for calculating the HI is age, a DAI is not provided. However, age is known for 86% of transformers in-service. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.6 Overhead Gang Operated Switch

3.1.6.1 Condition Assessment Methodology

Overhead gang operated switch is the first major sub-class of the switch asset group in Festival Hydro. Festival Hydro's risk management continues to manage the asset's risk of failure through regular visual inspections and infrared (IR) scanning. The outputs of the visual inspections and IR scanning assist Festival Hydro in determining appropriate maintenance interventions, however, there is no condition data that can be utilized for an ACA currently.

The Health Index for overhead gang operated switches is calculated by considering only service age. Table 3-12 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-12: Overhead Gang Operated Switch Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
				MAX SCORE	**4**

Since the service age provides a reasonably good measure of the remaining life of overheard gang operated switches, it is employed as an assessment parameter. Table 3-13 presents the service age condition rating.

Table 3-13: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 41 years

3.1.6.2 Results of Analysis

Age Assessment

Festival Hydro owns 117 overhead gang operated switches within its service territory. Figure 3.16 presents the age distribution.

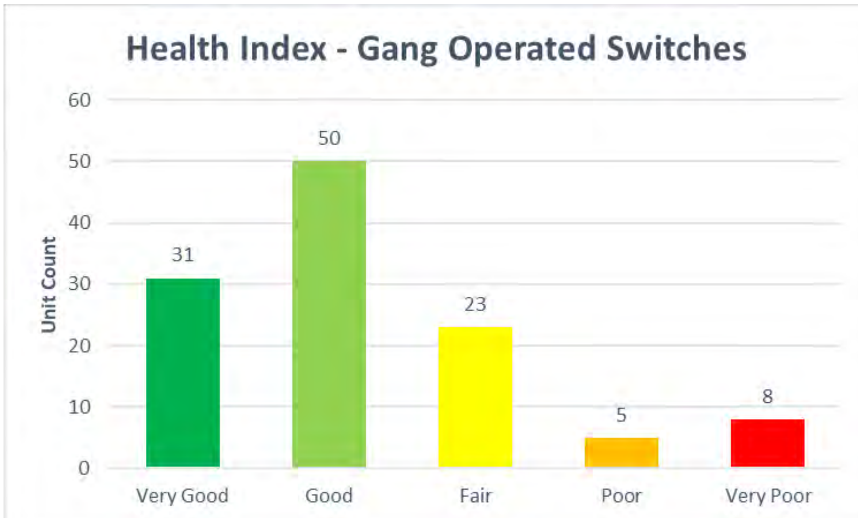
Figure 3.16: Overhead Gang Operated Switch Age Demographic

Condition Assessment

Festival Hydro's 2018 overhead switch data was used to calculate the Health Index based on the criteria provided in Table 3-12. The overall Health Index distribution is presented in Figure 3.17.

Festival Hydro manages the failure risk through its maintenance programs and remedy actions. The identified Poor and Very Poor switches are targeted to those that have reached and passed the TUL that now carry an increased risk of failure due to age. Typically, as an asset ages, the condition of the asset deteriorates quicker.

Figure 3.17: Overhead Gang Operated Switch Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. Since the only parameter used for calculating the HI is age, a DAI is not provided. However, the age is known for all gang operated switches in-service. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.7 Switchgear

3.1.7.1 Condition Assessment Methodology

Switchgear is the second major sub-class of the switch asset group in Festival Hydro. Festival Hydro's risk management continues to manage the asset's risk of failure through regular visual inspections and infrared (IR) scanning. The outputs of the visual inspections and IR scanning assist Festival Hydro in determining appropriate maintenance interventions, however, there is no condition data that can be utilized for an ACA currently.

The Health Index for pad mounted switchgear is calculated by considering only service age. Table 3-14 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-14: Switchgear Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
				MAX SCORE	**4**

Since the service age provides a reasonably good measure of the remaining life of switchgears, it is employed as an assessment parameter. Table 3-15 presents the service age condition rating.

Table 3-15: Criteria for Service Age

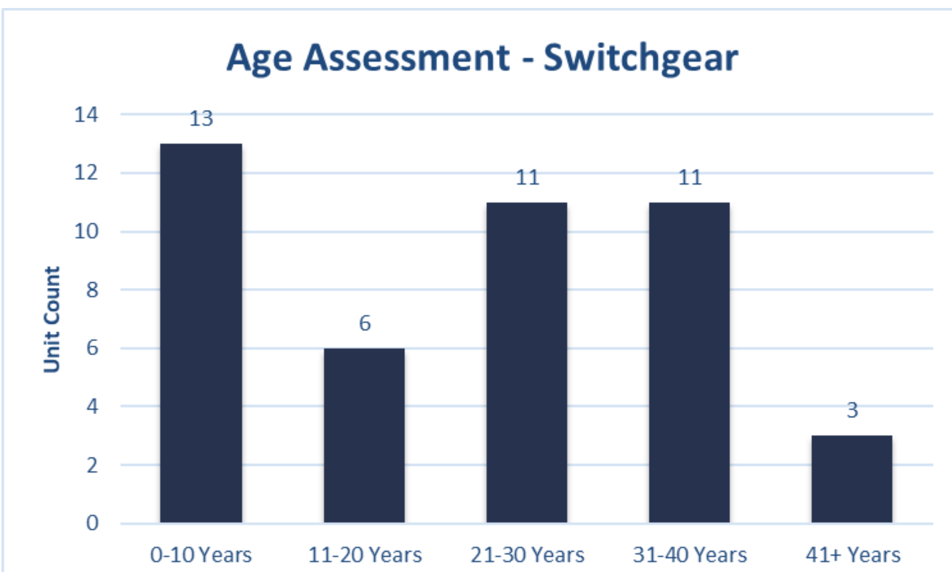
Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 41 years

3.1.7.2 Results of Analysis

Age Assessment

Festival Hydro owns 44 switchgears within its service territory. Figure 3.18 presents the age distribution.

Figure 3.18: Switchgear Age Demographic

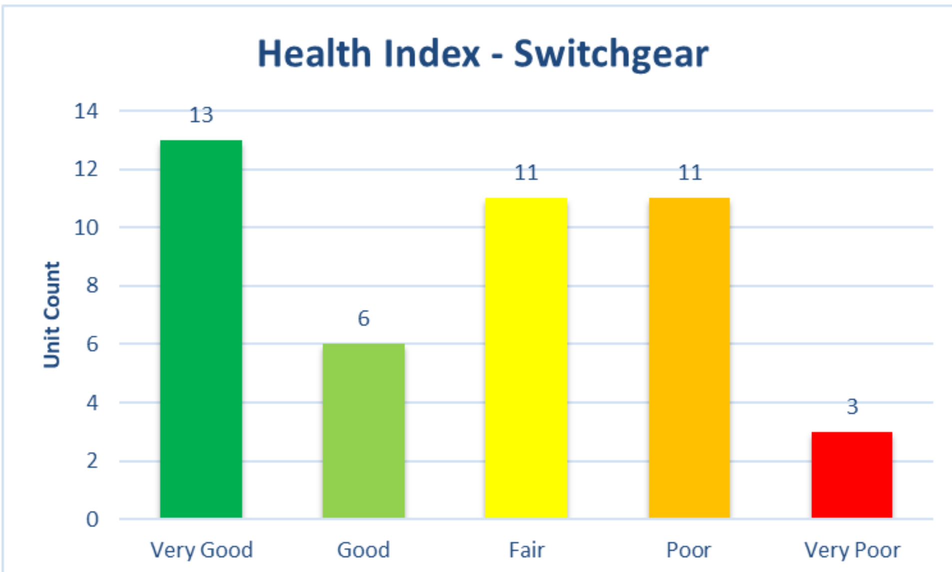


Condition Assessment

Festival Hydro's 2017 switchgear data was used to calculate the Health Index based on the criteria provided in Table 3-14. The overall Health Index distribution is presented in Figure 3.19.

Festival Hydro manages the failure risk through its maintenance programs and remedy actions. The identified Poor and Very Poor switchgears are targeted to those that have reached and passed the TUL that now carry an increased risk of failure due to age. Typically, as an asset ages, the condition of the asset deteriorates quicker.

Figure 3.19: Switchgear Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. Since the only parameter used for calculating the HI is age, a DAI is not provided. However, age is known for 94% of switchgears in-service. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.8 Vault and Manhole

3.1.8.1 Condition Assessment Methodology

Festival Hydro hired a third-party contractor to complete an assessment on a subset of Festival's vaults and manholes to identify deficiencies on the lid, roof slab, walls and floor. The assessment included a delamination survey (hammer sounding) of the interior of the structures and a visual inspection. The condition evaluation was given a rating between 1 to 5 for each component of the civil structure. Table 3-16 and Table 3-17 are used to calculate the Health Index for the inspected vaults and manholes.

Table 3-16: Vault & Manhole Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Lid condition	4	A,B,C,D,E	4,3,2,1,0	16
2	Roof slab condition	6	A,B,C,D,E	4,3,2,1,0	24
3	Wall condition	2	A,B,C,D,E	4,3,2,1,0	8
4	Floor condition	2	A,B,C,D,E	4,3,2,1,0	8
				MAX SCORE	**56**

Table 3-17: Criteria for Vault & Manhole Components

Condition Rating	Corresponding Condition
A	For the following components, the rating is 5 - Lid, Roof Slab, Walls, Floor
B	For the following components, the rating is 4 - Lid, Roof Slab, Walls, Floor
C	For the following components, the rating is 3 - Lid, Roof Slab, Walls, Floor
D	For the following components, the rating is 2 - Lid, Roof Slab, Walls, Floor
E	For the following components, the rating is 1 - Lid, Roof Slab, Walls, Floor

3.1.8.2 Results Analysis

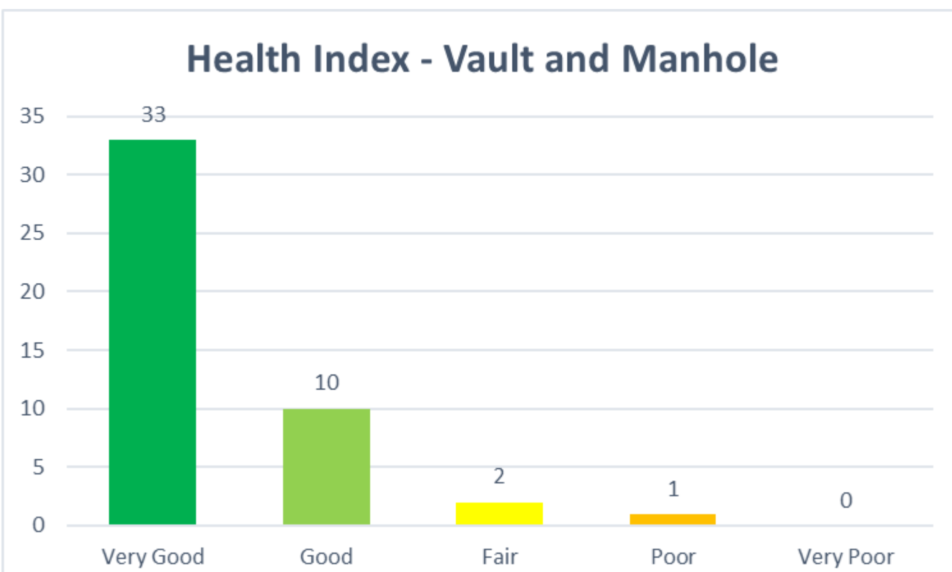
Age Assessment

Ages are unknown for the inspected vaults and manholes and since a visual inspection was done, age is not useful or needed.

Condition Assessment

46 vaults and manholes were observed and documented within the third-party contractor’s report. Figure 3.20 shows the Health Index demographic of the 46 observed vaults and manholes.

Figure 3.20: Vault & Manhole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for vault and manhole data is 100% for the inspected asset population. Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.2 Meters

Festival Hydro tracks and records the age of in-service meters within Festival Hydro's distribution system. In most cases, an ACA report does not include meters due to the limited condition data collected and the fact that meters are mandated by the regulator for connections and operation to read the usage of electricity. The quantities for each type and age are presented within this report to highlight all assets managed by Festival Hydro that require a renewal program.

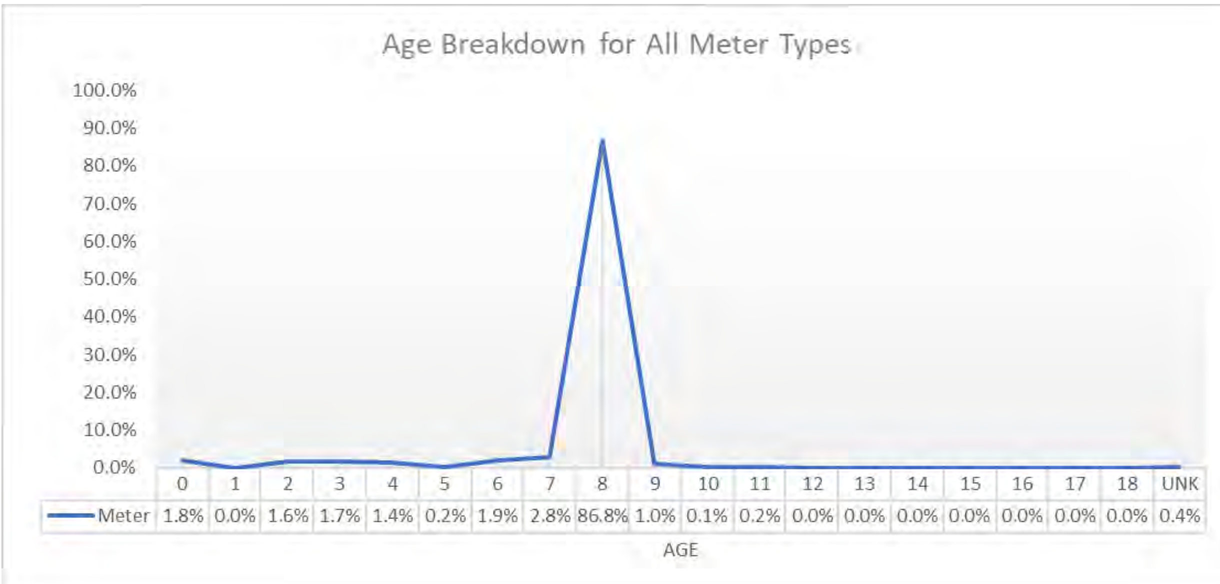
Festival Hydro uses four category classifications for meters: Advanced, ICI External ITs, ICI Self Contained, and Residential. Table 3-18 presents the quantity in-service for each of these meter categories as well quantity of repeaters.

Table 3-18: In-service Smart Meter and Repeater Quantity

Meter Category	Quantity	TUL	Assets Reaching TUL next 5 Years
Advanced	12	20	0
ICI External ITs	808	15	58
ICI Self Contained	803	15	0
Residential	20996	10	19556
Repeaters	91	10	91

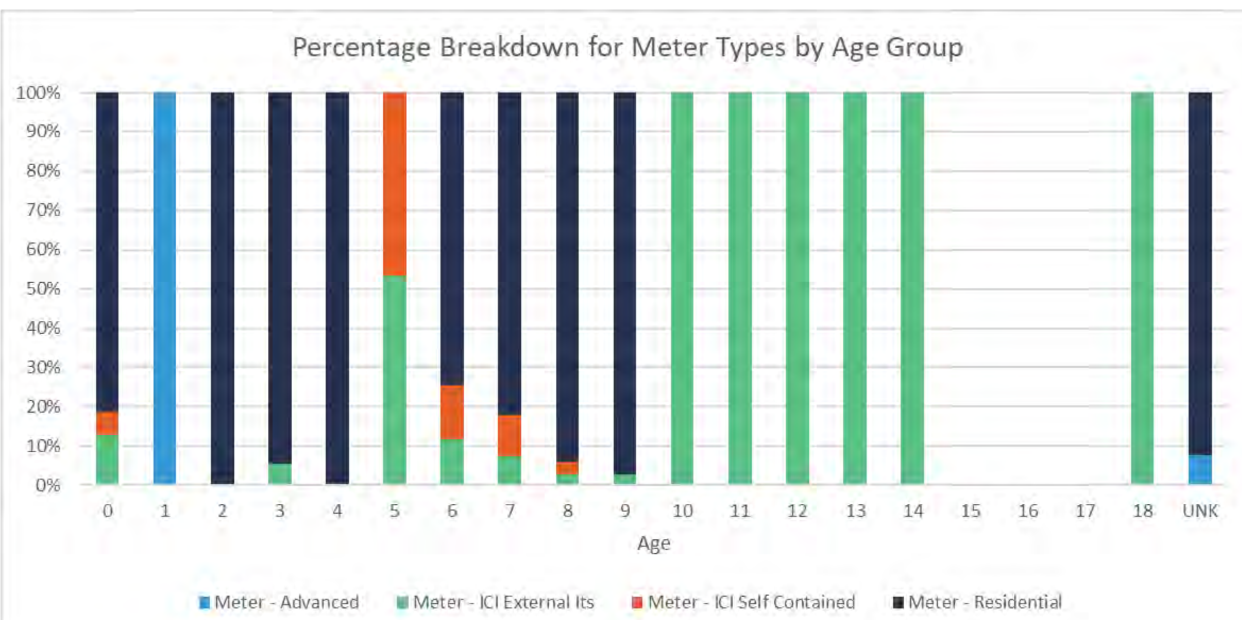
A percent distribution for all meter types by age is shown in Figure 3.21. Majority of meters (86.8%) currently in-service are at age 8 from the original seal date. Smart meter replacements occur 10 years after the initial seal date. However, a subset population of smart meters can be tested (i.e. reverification) if they are still performing well. Of all smart meter types in Festival Hydro's system, 64% have a slated 2020 reverification year. If the tested subset of meters passes the reverification test, the meters can continue being in-service for an additional eight years providing a cost avoidance for Festival Hydro. However, should the subset of meters fail the reverification test, the whole meter group with a 2020 reverification year will need to be replaced. Furthermore, 93% Festival Hydro's residential meters will reach their typical useful life within the next five years. Each asset age group will be sample tested to determine if the asset is suitable in continuing service. Additionally, all repeaters will reach their typical useful life within the next five years.

Figure 3.21: Meter Age Demographics by Percent



In addition, Figure 3.22 visualizes the percentage breakdown of meters found in each age group. All meters found to be at age 1 are Advanced meters. All Residential meters are under 10 years of age and contribute to most meter types for those age groups.

Figure 3.22: Meter Type Distribution by Age Group



SecureMesh Collectors

Festival Hydro tracks the quantity and age of SecureMesh Collector's in-service within Festival Hydro's distribution system. A SecureMesh™ Collector serves as an access point for SecureMesh-enabled meters and devices. Each SecureMesh Collector defines a subnetwork of the overall SecureMesh Neighborhood Area Network (NAN), supporting communications to and from the headend for the SecureMesh NAN nodes with which it communicates. SecureMesh Collectors establish the network time synchronization, coordinates overall operation of the wireless mesh network and provides local data storage as a form of data redundancy.[3][4]

Usually an ACA report does not include this asset due to limited condition data collected. However, the quantities for each type are presented within this report to highlight all assets managed by Festival Hydro that require a renewal program in the forthcoming years.

Festival Hydro uses two types of collectors - NCXL900HXBE-B BELL SecureMesh Collector and COLL-3100 SecureMesh Collector. Festival Hydro has 103 collectors, highlighted in Table 3-19. No additional condition information is collected at the time of compiling the report pertaining to the collectors. As seen in the table below, majority of collectors will reach their typical useful life in the next two years. Festival Hydro will replace the collectors as they begin to fail and will be either upgraded to a newer asset or repaired dependent on location.

Table 3-19: Collectors in-service at Festival Hydro

Description	Age	Quantity	TUL
NCXL900HXBE-B BELL SecureMesh Collector	8	100	10
COLL-3100 SecureMesh Collector	4	3	

3.3 Station Assets

3.3.1 Substation Power Transformer

There are four power transformers owned by Festival Hydro. These are referenced as Welsh St, Chalk St, 8051T1 and 8051T2.

3.3.1.1 Condition Assessment Methodology

The Health Index for substation power transformers is calculated by considering a combination of condition criteria obtained from Festival Hydro's inspection records. Table 3-20 summarizes the methodology to combine these criteria into an overall Health Index.

[3] Trilliant SecureMesh™ Collector Datasheet
[4] Trilliant Securemesh™ 3100 Collector (COLL-3100) Datasheet

Table 3-20: Substation Power Transformer Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Dissolved Gas Analysis	10	A,B,C,D,E	4,3,2,1,0	40
2	Load History	10	A,B,C,D,E	4,3,2,1,0	40
3	Insulation Power Factor	10	A,B,C,D,E	4,3,2,1,0	40
4	Oil Quality	8	A,B,C,D,E	4,3,2,1,0	32
5	Service Age	6	A,B,C,D,E	4,3,2,1,0	24
6	Visual Inspection – Exterior	4	A,C,E	4,2,0	16
7	Visual Inspection – General	4	A,C,E	4,2,0	16
8	Visual Inspection – Electrical	4	A,C,E	4,2,0	16
9	Visual Inspection – Environmental	4	A,C,E	4,2,0	16
				MAX SCORE	**240**

Table 3-21 to Table 3-25 provide the condition rating translation for the various condition criteria used within the Health Index algorithm. To determine the condition of the dissolved gas analysis (DGA), DGA condition criteria requires data on gas concentrations (obtained from transformer inspections) and dissolved gas rate of change (obtained from the two most recent inspections). For both DGA and Oil Quality, the worst condition is taken as the dominant grade.

Table 3-21: Criteria for DGA Results

Gas Condition	Gas Generation Rate		
	Low	Low to High	High
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

Table 3-22: Criteria for Load History

Condition Rating	Corresponding Condition
A	LS ≥ 3.5
B	2.5 ≤ LS < 3.5
C	1.5 ≤ LS < 2.5
D	0.5 ≤ LS < 1.5
E	LS < 0.5

Table 3-23: Insulation Power Factor

Condition Rating	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

Table 3-24: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class		Grade
	U ≤ 69 kV	69 kV < U < 230 kV	
Acid Number	≤0.05	≤0.04	A
	0.05-0.20	0.04-0.15	C
	≥0.20	≥0.15	E
IFT [mN/m]	≥30	≥35	A
	25-30	30-35	C
	≤25	≤30	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	>28 (1mm gap) >47 (2mm gap)	A
	≤40	≤47	E
Water Content [ppm]	<35	<25	A
	≥35	≥25	E

Table 3-25: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	More than 60 years
E	-

Condition rating for visual inspections follow Table 3-26. Station inspections by Festival Hydro are ranked between “Satisfactory” and “Unsatisfactory” or provided a ranking value between “1” and “3”, where “3” is in Good condition and “1” is in Poor condition. Therefore, the condition rating is translated to a three-level score compared to the best practices of a five-level score.

Table 3-26: Criteria for Visual Inspection (Includes exterior, general, electrical and environmental)

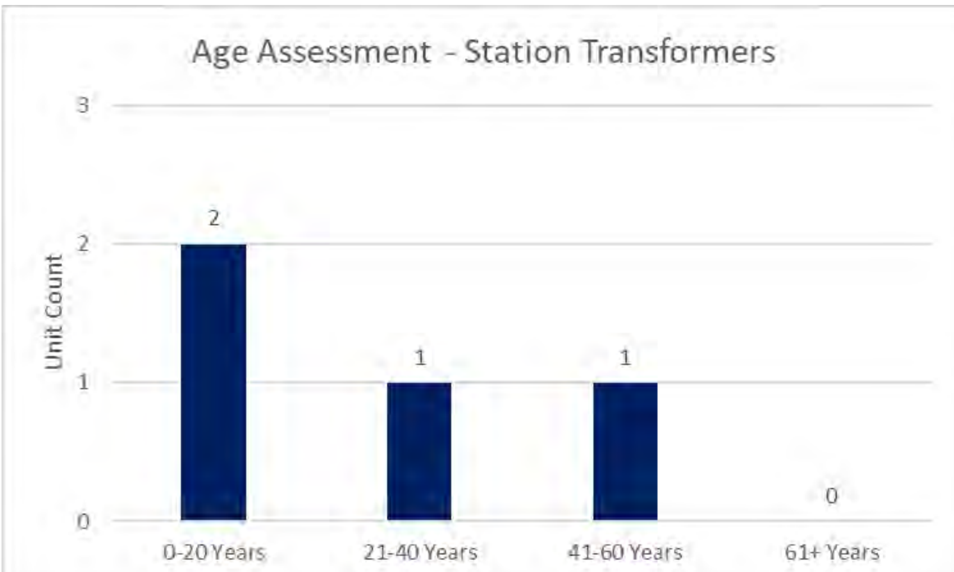
Condition Rating	Corresponding Condition
A	Satisfactory or 3 - Good condition
C	2 - Fair condition
E	Unsatisfactory or 1 - Poor condition

3.3.1.2 Results of Analysis

Age Assessment

Figure 3.23 presents the age profile of substation power transformers in-service at Festival Hydro.

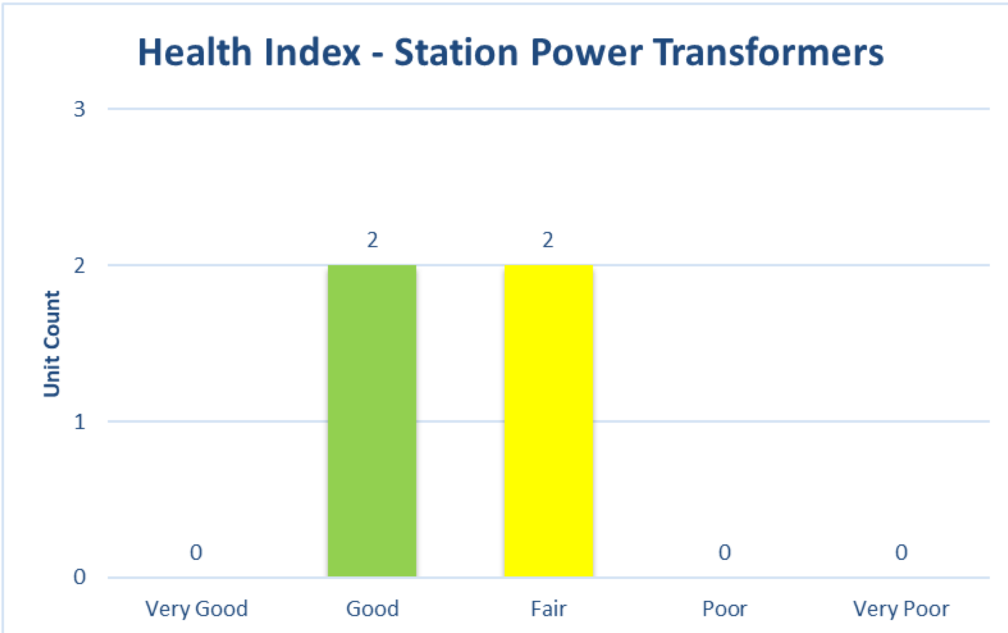
Figure 3.23: Substation Power Transformer Age Demographic



Condition Assessment

Festival Hydro's most recent transformer inspections were used to calculate the Health Index based on the criteria provided in Table 3-20 and the criteria's respective tables. The overall Health Index distribution is presented in Figure 3.24.

Figure 3.24: Substation Power Transformers Health Index Demographic



Substation power transformers found at the Festival MTS#1 location in Stratford are in Good condition and no response is required aside from regular inspection and maintenance to maintain the condition. Both Welsh St. and Chalk St. substation power transformers are in Fair condition, with Welsh St. substation power transformer slightly worse in comparison to Chalk St. These power transformers should be continued to be maintained in the short-term to preserve its functionality. However, in the long-term alternatives should be explored and evaluated to bring the condition of the asset's back to Very Good.

Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The average DAI for station power transformer data is 92%. Section 4.0 provides additional recommendations for data collection for HI improvement.

3.3.2 Switchgears for substation Welsh St. & Chalk St.

Through a recent inspection of the switchgears at substation Welsh St. and Calk St., the assets are identified to be in Fair condition and are performing satisfactorily for Festival Hydro. Additionally, both switchgears at these substations are older than 30 years. Festival Hydro should consider replacing these switchgears at the same time the substation power transformer will be replaced for additional benefits such as operation efficiency and cost savings. The table below presents the provided recorded results of the two switchgears inspected.

Table 3-27: Substation Switchgear Data

Switchgear substation location	Manufacturer / Type	Rating	Age	Condition
Welsh St.	S&C	4.76 kV, 1200 A, 60 kV BIL, 25 kA IC	33	Fair
Chalk St.	S&C / Alduti-Rupters with SM-5 fusing	4.8 kV, 600 A, 60 kV BIL, 40 kA IC	34	Fair

3.3.3 Festival MTS#1 TS

In addition to the two power transformers 8051T1 (RA110397) and 8051T2 (RA110398), the auxiliary equipment and assets are tracked and have a recorded age presented in Table 3-28. The typical useful life (TUL) is derived from the Asset Depreciation Study performed for the OEB in 2010[5]. Where a TUL was not defined, a Festival Hydro specific TUL is used – this is marked in the table with an asterisk (*). Where an asset is approaching the TUL, a planned replacement should take place to maintain the performance of Wright TS. An ACA is typically not completed on the assets identified in the table aside from the ones that are highlighted.

Table 3-28: Wright TS Auxiliary Equipment

Asset Description	Age	TUL	Quantity
HV Circuit SW – Air Insulated	5	50	6
Metering - IT	5	35-50	7
Neutral Ground Reactor	6	40	2
Battery Charger	6	20	2
Battery	6	15	120
Insulators	6	60 *	178
Microprocessor Relays	6	20	28
Rigid Bus	6	55	
Oil Containment	6	30 *	
Transfer Switch	6	20 *	3
ULTC	6	30	2
ULTC Controller	6	20 *	2

[5] Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc., 2010

4 Recommendations

Recommendations are aggregated into this stand-alone section however; detailed recommendations are provided for each asset group in Sections 3.1. While Festival Hydro has been conducting regular visual inspections as per the DSC requirements, there are limited asset inspection records. Though it may be costly for a small utility, obtaining asset condition data is valuable in justifying capital and operational expenditures, maintenance activities, inspection intervals, and validating the collection of data points. Additionally, keeping records of assets condition is good practice as it may assist in planning and assessing the quality of assets being replaced in-service.

METSCO's strongest recommendation is that Festival Hydro begin collecting and keeping condition records consistent for all assets inspected rather than checking for a pass/fail criterion, targeting the assets with a degraded nature. This will establish a stronger baseline of the asset health indices rather than being dependent on age. METSCO recommends Festival Hydro to incorporate a five-level grading scheme for any asset condition inspections where applicable and be generally consistent with ISO55000 practices. A five-level grading scheme will allow for more discrepancy between assets and their respective Health Index values that will be used for prioritizing assets.

4.1 Pole

Table 4-1 identifies the data gaps present in Festival Hydro's visual inspection records for poles. A data gap is an identified data point that can be used as part of the Health Index Formulation. We recommend for Festival Hydro to investigate the possibility of collecting this data point moving forward to improve the accuracy of the Heath Index. The priority is given in relation to other criteria recommended to be collected for the asset based on the Best Practice Health Index Formulation. Criterions with higher weights received a higher priority.

Table 4-1: Data Collection Recommendation for Wood Pole

Criteria	Reasoning	Priority
Visual Inspection - Wood Rot	Identification of wood rot location and the degree of wood rot will identify the pole's safety factor and condition. Wood is a natural material, so it is very likely rot can form regardless of any protection used.	**High**
Visual Inspection - Defects	Identifying defects of a pole could prevent premature failure. Defects can result in loss of strength or ability to not maintain good operating conditions.	**High**
Visual Inspection - Out of Plumb	Poles with an excessive lean should be identified as accurately as possible. Poles with a large displacement are considered a large safety liability or reliability issue for the utility – in either case the poles would be very likely to be at end of life.	**Low**

Table 4-2: Data Collection Recommendation for Concrete Pole

Criteria	Reasoning	Priority
Visual Inspection - Defects	Identifying defects of a pole could prevent premature failure. Defects can result in loss of strength or ability to not maintain good operating conditions.	High
Visual Inspection - Rust/Corrosion	Like wood rot, although rust is mostly found on concrete and steel poles. Presence of rust compromises the poles strength and should be identified, both location and degree of rust.	High
Visual Inspection - Concrete Spalling	Like wood rot, although concrete spalling is only found on concrete poles. Presence of rust compromises the poles strength and should be identified, both location and degree of rust.	Medium
Visual Inspection - Out of Plumb	Poles with an excessive lean should be identified as accurately as possible. Poles with a large displacement are considered a large safety liability or reliability issue for the utility – in either case the poles would be very likely to be at end of life.	Low

4.2 Overhead Primary Conductor

The Health Index for overhead primary conductors is determined with the use of two criteria: age and small conductor risk. Small conductor risk is a criterion as it is sometimes identified as having increased risk of becoming brittle and failing. Should Festival Hydro not identify any small conductor in-service then the Health Index Formulation provided is accurate and does not require a change. However, if small conductors are in-service, it is recommended to remove the conductors to reduce the failure risk.

4.3 Underground Primary Cable

Table 4-3 identifies the data gaps present in Festival Hydro's underground cable data. A data gap is an identified data point that can be used as part of the Health Index Formulation. We recommend for Festival Hydro to investigate the possibility of collecting this data point moving forward to improve the accuracy of the Heath Index. A priority is given in relation to other criteria recommended to be collected for the asset based on the Best Practice Health Index Formulation. Criterions with higher weights received a higher priority.

Table 4-3: Data Collection Recommendation for Underground Primary Cable

Criteria	Reasoning	Priority
Cable Failure	Collecting cable failure results and identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable condition.	**High**
Field Testing	Like cable failure, field testing will result in an improvement of understanding the condition of the utility's asset.	**High**
Condition of Concentric Neutral	Like cable failure, field testing will result in an improvement of understanding the condition of the utility's asset.	**High**
Outage Records	Collecting outage records with their known location would identify which feeder section are in poorer condition that will require replacement as it may be more cost effective to replace rather than maintain.	**Medium**
Loading History	Overloading cables results in temperature increases overtime causing accelerated degradation of the cable.	**Low**
Visual Inspections of Splices	A visual inspection would identify if the splice is in good or bad condition; with it being in a bad condition could result in moisture ingress that will further pose problems for the asset and utility.	**Low**

4.4 Distribution Transformer

Table 4-4 identifies the data gaps present in Festival Hydro's distribution transformers data. A data gap is an identified data point that can be used as part of the Health Index Formulation. We recommend for Festival Hydro to investigate the possibility of collecting this data point moving forward to improve the accuracy of the Heath Index. A priority is given in relation to other criteria recommended to be collected for the asset based on the Best Practice Health Index Formulation. Criterions with higher weights received a higher priority.

Table 4-4: Data Collection Recommendation for Distribution Pole-Mount Transformer

Criteria	Reasoning	Priority
Visual Inspection	Identifying defects present on asset would inform user of degradation and potential maintenance tasks to be completed.	**High**
IR Scan result	It would be beneficial for assets to have IR scans completed since identification of hot spots jeopardizes the safe on-going operation of the asset.	**Medium**
Peak Loading	Transformers that are overloaded will exhibit accelerated degradation of the insulation found within the asset.	**Low**

Table 4-5: Data Collection Recommendation for Distribution Pad-Mount Transformer

Criteria	Reasoning	Priority
Condition of Pad	It is likely that a failed transformer pad will also result in the replacement of the transformer it is supporting.	**High**
Visual Inspection	Identifying defects present on asset would inform user of degradation and potential maintenance tasks to be completed.	**High**
IR Scan result	It would be beneficial for assets to have IR scans completed since identification of hot spots jeopardizes the safe on-going operation of the asset.	**Medium**
Peak Loading	Transformers that are overloaded will exhibit accelerated degradation of the insulation found within the asset.	**Low**

4.5 Overhead Gang-Operated Switch & Switchgear

Table 4-6 identifies the data gaps present in Festival Hydro's switch data. A data gap is an identified data point that can be used as part of the Health Index Formulation. We recommend for Festival Hydro to investigate the possibility of collecting this data point moving forward to improve the accuracy of the Heath Index. A priority is given in relation to other criteria recommended to be collected for the asset based on the Best Practice Health Index Formulation. Criterions with higher weights received a higher priority.

Table 4-6: Data Collection Recommendation for Switch & Switchgear

Criteria	Reasoning	Priority
Infrared Scanning	It would be beneficial to keep accurate records of assets that have IR scans completed since identification of hot spots jeopardizes the safe on-going operation of the asset.	**High**
Visual Inspection - Condition of Enclosure	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Interphase Barriers	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection and/or Corona testing - Condition of Terminations	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Blades	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Low**
Visual Inspection - Condition of Pad (If applicable)	The civil infrastructure that holds the asset is an important component to look at as it contributes to the foundation of the asset and as a barrier to the outside environment.	**Low**

4.6 Vault & Manhole

METSCO recommends Festival Hydro to conduct cyclic vault-manhole condition assessment similar to the previous one completed. Though some changes may be seen, having a recent data assessment of the civil assets to justify investments is beneficial and will assist in future plans.

In addition, METSCO recommends evaluating the historical flooding incidents and mitigation measures at each location. Flooding accelerates the degradation of civil structures through cracking which overall weakens the structure.

4.7 Substation Power Transformer

Table 4-7 identifies the data gaps present in Festival Hydro's distribution substation data. A data gap is an identified data point that can be used as part of the Health Index Formulation. We recommend for Festival Hydro to investigate the possibility of collecting this data point moving forward to improve the accuracy of the Heath Index. A priority is given in relation to other criteria recommended to be collected for the asset based on the Best Practice Health Index Formulation. Criterions with higher weights received a higher priority.

Table 4-7: Data Collection Recommendations for Substation Power Transformers

Criteria	Reasoning	Priority
Infrared Scanning	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Visual Inspection and/or Corona testing - Bushing Condition	Identifying defects to the bushings provides valuable condition data and more importantly if the issue is reoccurring after being addressed.	**Medium**
Visual Inspection - Main Tank Corrosion	Identifying presence of corrosion compromises the strength of the tank. Both the location and degree (low, medium, high) of rust presence should be captured over time.	**Medium**
Visual Inspection - Cooling Equipment	Identifying presence of corrosion/wear compromises the equipment. Both the location and degree (low, medium, high) of rust/wear presence should be captured over time.	**Medium**
Visual Inspection - Oil Tank Corrosion	Identifying presence of corrosion compromises the strength of the tank. Both the location and degree (low, medium, high) of rust presence should be captured over time.	**Medium**
Visual Inspection - Foundation	Identifying presence of wear compromises the foundation. Both the location and degree (low, medium, high) of wear presence should be captured over time.	**Low**
Visual Inspection and/or field testing - Grounding	Identification of wear over time provides condition data of the grounding unit found in station transformers.	**Low**
Visual Inspection - Gaskets and Seals	Identification of wear over time provides condition data of the gaskets/seals found in station transformers.	**Low**
Visual Inspection - Connectors	Identification of wear over time provides condition degradation data of the asset.	**Low**
Visual Inspection - Oil Leaks	Identification of oil leaks, or residue and markings of oil leaks on equipment provides condition degradation data on the asset. Continuous problems would be addressed immediately for safe operation of asset.	**Low**
Visual Inspection - Oil Level	Identifying the oil level is within acceptable range of operation from previous inspection.	**Low**

4.8 Substation Assets

Additional substation assets can be evaluated through the Asset Condition Assessment methodology, though it is advised for Festival Hydro to begin recording the condition results rather being dependent on age. Additionally, Festival Hydro should explore options in collecting the condition data that can be used as part of the ACA. The list below contains assets that can be assessed as part of an ACA with condition criteria such as:

- Switchgears
  - Condition of metal clad cubicle & components
  - Breaker truck condition
  - Condition of control & operating mechanism components

   - Overall switchgear condition
   - Time/travel test results
   - Contact resistance test results
   - Oil / SF_6 leaks (if applicable)
   - Oil / SF_6 gas tests (if applicable)
- Circuit breakers/recloser
   - Condition of bushing/support insulators
   - Condition of control & operating mechanism components
   - Condition of foundation, support steel, grounding
   - Overall circuit breaker condition
   - Timing/travel test results
   - Infrared scan results
   - Additional conditional inspection dependent on circuit breaker sub-type (oil, air, vacuum, SF_6)
- HV circuit switch
   - Condition of insulators
   - Condition of drive train assembly
   - Condition of operator and controls
   - Condition of disconnect live parts (if applicable)
   - Condition of foundation, support steel, grounding
   - Condition of connectors and conductors
   - Timing/travel test results
   - Contact resistance test results
   - Infrared scan results
- Scada-mate switch
   - Condition of enclosure
   - Condition of interphase barriers
   - Condition of terminations
   - Condition of blades
   - Condition of operating mechanism
   - Infrared scan results
- Battery and Charger
   - Age of battery/charger
   - Charge test results

5 Asset Replacement Plan

5.1 Purpose

Based on the condition assessment of major assets employed in substations, overhead lines and underground distribution system, this section provides the projected quantities of assets that would likely require replacement for the next short-term planning years 2019 to 2024.

The following major classes of assets are considered:

- Distribution poles
- Distribution transformers
- Underground primary cables
- Overhead gang-operated switches
- Switchgears
- Distribution substation power transformers

Overhead conductors typically outlive the poles which support them and are replaced when the poles are replaced, therefore are not considered. Additionally, vaults and manholes are not discussed within this section as the information collected to date does not encompass a recent representation of the current population. Meters are not discussed as these assets are regulated and are on a predetermined renewal cycle, dependent on the reverification test year results. Furthermore, until additional condition data can be acquired for the remaining substation components, those too are not mentioned further within this section.

The long-term trending approach considers expected aging and degradation for each asset and attempts to smooth investment requirements over the planning period. Vaults and manholes are not considered within this section since the reported Health Index results are presented for only a subset population of the asset and it is not accurate to represent the total population. However, it is advised to look at the possibility of renewing some of the oldest units within this asset class.

5.2 Approach

The ACA provides the Health Index distribution for each asset. The Health Index is a percentage score between 0 and 100, used to assess the condition of an asset. The condition-based intervention approach based on the asset's condition is shown in Table 5-1. This is a general approach, which can vary between assts and based on budget constraints. For each asset type a ranged quantity of asset replacements for each year is estimated. However, the replacements are on Health Index, testing and field inspection of assets performed in samples. Continuous monitoring of the asset by inspectors will provide current asset's condition assessment.

Table 5-1: Health Index definition and intervention approach

Health Index (%)	Condition	Intervention Approach
85 - 100	Very good	None
70 - 85	Good	None
50 - 70	Fair	Replace within 3-10 years
30 - 50	Poor	Replace within 1-3 years
0 - 30	Very poor	Replace immediately

In addition to the condition of the assets, the asset's age, specifically the Typical Useful Life (TUL), can be a determining driver for asset renewal because as the asset reaches and passes the TUL, the rate at which the asset's condition deteriorates increases. Furthermore, even though visual inspection records may result in a calculated Health Index to be in Good condition for an asset reaching or past TUL carries an increased risk of failing and quickly deteriorating from Good to Very Poor. Minimum, maximum and TUL values for Festival Hydro are assumed based on the *Asset Depreciation Study for the Ontario Energy Board*, as summarized in Table 5-2.

Table 5-2: Useful life measures for selected asset classes

Asset Class	Minimum UL	TUL	Maximum UL
Wood pole	35	45	75
Concrete pole	50	60	80
Underground primary cable	35	40	55
Pole-mount transformer	30	40	60
Pad-mount transformer	25	40	45
Overhead gang-operated switch	30	45	55
Switchgear	20	30	45
Vault/Manhole	50	60	70
Power transformer	35	45	60

5.3 Poles

The age and Health Index demographics are depicted in Table 5-3 and Table 5-4, respectively. Approximately 3% of the poles are below Fair condition, whereas approximately 32% of wood poles have reached or passed the TUL.

Table 5-3: Age distribution for poles

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Wood Pole	583	77	229	363	707	437
Concrete Pole	1183	1530	644	176	141	1

Table 5-4: Health Index distribution for poles

Asset	Very Good	Good	Fair	Poor	Very Poor
Wood Pole	1074	1177	103	30	12
Concrete Pole	1183	2174	176	141	1

To keep the risk of in-service equipment failure at acceptable levels and to mitigate deterioration in supply system reliability, Table 5-5 provides the replacement recommendation for asset renewal of poles expected to reach the end of their useful service life during the next six years.

The replacement plan for wood poles prioritizes those poles that are rated as Poor and Very Poor and are past the TUL of a wood pole. Based on the large amount of poles past the TUL and to reduce the risk of failed wood poles due to age, it is recommended for Festival Hydro to replace a significant amount of poles each year as shown in Table 5-5. However, the current condition data collected to date does not support that wood poles past the TUL are experiencing unfavorable conditions and require attention for replacement. METSCO recommends for Festival Hydro to conduct a visual inspection on a subset of wood poles past the TUL to determine if the wood poles are in fact in acceptable service conditions or require asset intervention (i.e. asset renewal).

Should the outcome of the visual inspection of the subset show the condition of poles are acceptable for service, the recommended replacement can be revised for a decrease in wood poles to be replaced, shown in the table below. It is expected that with the rigorous risk management the TUL could be extended to 55 years, in which case replacing 70 poles per year would maintain system health. The option with inspecting wood poles past the TUL provides the added benefit for Festival Hydro to ensure that they are replacing assets that require replacement due to their condition. This benefits the customer service expectations as there are reduced planned outages, a reduced renewal budget and maintains the service reliability of the system.

Table 5-5: Projected replacement for poles

Quantity of Assets Recommended for Replacement						
Year	2019	2020	2021	2022	2023	2024
TUL = 45 years						
Wood Pole	160	160	160	200	210	210
Concrete Pole	13	20	27	30	30	30
TUL = 55 years						
Wood Pole	70	70	70	70	70	70
Concrete Pole	13	20	27	30	30	30

5.4 Underground Primary Cable

The age and Health Index demographics are depicted in Table 5-6 and Table 5-7, respectively.

Table 5-6: Age distribution for underground primary cable (m)

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Underground Primary Cable (m)	46385	68265	38895	21738	0	0

Table 5-7: Health Index distribution for underground primary cable (m)

Asset	Very Good	Good	Fair	Poor	Very Poor
Underground Primary Cable (m)	74748	77409	18319	4807	0

To keep the risk of in-service equipment failure at acceptable levels and to mitigate deterioration in supply system reliability, Table 5-8 provides the replacement recommendation for asset renewal of underground primary cable expected to reach the end of their useful service life during the next six years.

Table 5-8: Projected replacement for underground primary cable (m)

Quantity of Assets Recommended for Replacement						
Year	2019	2020	2021	2022	2023	2024
Underground Primary Cable (km)	2.1	3.2	3.7	6.0	6.0	6.0

5.5 Distribution Transformer

The age and Health Index demographics are depicted in Table 5-9 and Table 5-10, respectively. Approximately 5% of the transformers are below Fair condition.

Table 5-9: Age distribution for distribution transformers

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Pole-mount transformer	187	454	310	38	0	0
Pad-mount transformer	219	363	350	56	0	0

Table 5-10: Health Index distribution for distribution transformers

Asset	Very Good	Good	Fair	Poor	Very Poor
Pole-mount transformer	187	454	310	38	0
Pad-mount transformer	219	363	350	56	0

To keep the risk of in-service equipment failure at acceptable levels and to mitigate deterioration in supply system reliability, Table 5-11 provides the replacement recommendation for asset renewal of transformers expected to reach the end of their useful service life during the next six years. However, the Health Index is solely dependent on age as a condition parameter and is advisable to expand the algorithm to other condition parameters. Continuous monitoring of the asset's condition throughout the years will identify if any further condition degradation continues and if it is necessary to be replaced. Additionally, distribution transformers are often managed on a run to failure scenario or are replaced through larger, planned renewal projects to minimize impacts and for optimal efficiency. The run to failure case is particularly true for overhead distribution transformers. Both cases will influence the replacement rate that Festival Hydro will plan for in the short term. Furthermore, old pole-mount transformers are typically found on old or failed wood poles and are replaced simultaneously for efficiency.

Table 5-11: Projected replacement for distribution transformers

Quantity of Assets Recommended for Replacement						
Year	2019	2020	2021	2022	2023	2024
Pole-mount transformer	9	9	9	9	12	12
Pad-mount transformer	11	11	11	11	14	14

5.6 Overhead Gang-operated Switch

The age and Health Index demographics are depicted in Table 5-12 and Table 5-13, respectively. Approximately 31% of the primary switches are at Fair condition or worse, suggesting a third of these assets will require replacement within the next 10 years.

Table 5-12: Age distribution for overhead gang-operated switches

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Overhead gang-operated switch	31	50	23	5	8	0

Table 5-13: Health Index distribution for overhead gang-operated switches

Asset	Very Good	Good	Fair	Poor	Very Poor
Overhead gang-operated switch	31	50	23	5	8

To keep the risk of in-service equipment failure at acceptable levels and to mitigate deterioration in supply system reliability, Table 5-14 provides the replacement recommendation for asset renewal of overhead gang-operated switches expected to reach the end of their useful service life during the next six years. However, the Health Index is solely dependent on age as a condition parameter and is advisable to expand the algorithm to other condition parameters. Continuous monitoring of the asset's condition throughout the years will identify if any further condition degradation continues and if it is necessary to be replaced.

Table 5-14: Projected replacement for overhead gang-operated switches

Quantity of Assets Recommended for Replacement						
Year	2019	2020	2021	2022	2023	2024
Overhead gang-operated switch	3	3	2	2	2	2

5.7 Switchgear

The age and Health Index demographics are depicted in Table 5-15 and Table 5-16, respectively.

Table 5-15: Age distribution for switchgears

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Switchgear	13	6	11	11	3	0

Table 5-16: Health Index distribution for switchgears

Asset	Very Good	Good	Fair	Poor	Very Poor
Switchgear	13	6	11	11	3

To keep the risk of in-service equipment failure at acceptable levels and to mitigate deterioration in supply system reliability, Table 5-17 provides the replacement recommendation for asset renewal of switchgear that are beyond the TUL and those expected to reach the TUL within the next six years. Switchgears are high impact assets, with failure that typically impact one or more feeders, and sometimes an entire station. In addition, as switchgears age, parts are increasingly difficult to source. Typically, switchgears are renewed well in advance of reaching risk of failure.

The current Health Index is solely dependent on age as a condition parameter and is advisable to continue to monitor the asset's condition moving forward to identify assets with a high-risk of failure are require immediate replacement.

Table 5-17: Projected replacement for switchgears

Quantity of Assets Recommended for Replacement						
Year	2019	2020	2021	2022	2023	2024
Switchgear	3	4	4	3	3	3

5.8 Power Transformer

The age and Health Index demographics are depicted in Table 5-18 and Table 5-19, respectively.

Table 5-18: Age distribution for power transformers

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Power transformer	2	0	0	1	0	1

Table 5-19: Health Index distribution for power transformers

Asset	Very Good	Good	Fair	Poor	Very Poor
Power transformer	0	2	2	0	0

To keep the risk of in-service equipment failure at acceptable levels and to mitigate deterioration in supply system reliability, Table 5-20 provides the replacement recommendation for asset renewal of power transformers expected to reach the end of their service life during the next six years. Welsh power transformer is identified to be replaced within the next six-year period. Although the power transformer was determined to be in Fair condition, it is currently been in service for 52 years. The TUL of a power transformer is 45 years. Previously mentioned, even though visual inspection records may result in a calculated Health Index to be in Fair condition for an asset past their TUL carry an increased risk of failing and can quickly deteriorate from Fair to Very Poor. Therefore, it is beneficial for Festival Hydro to replace the power transformer.

Table 5-20: Projected replacement for power transformers

Quantity of Assets Recommended for Replacement						
Year	2019	2020	2021	2022	2023	2024
Power transformer	0	0	0	Welsh	0	0

Attachment 13

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www.festivalhydro.com

January 4, 2018

BY RESS & COURIER

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Festival Hydro Inc. – ED-2002-0513
2020 Cost of Service ("COS") Application Deferral Request

Dear Ms. Walli,

Festival's last COS application (EB-2014-0073) was filed for rates effective January 1, 2015, however the Decision and Order and Final rate order were not received until May 28, 2015 and June 4, 2015 respectively and as such the Decision and Order indicated:

> *"Festival confirmed its request for a rate year alignment to January 1 in its draft rate order. Festival noted that although the effective date of the Decision and Order for 2015 rates is May 1, 2015, it is Festival's understanding that its rate year is now aligned with the fiscal year and that its next IRM application will be filed for rates effective January 1, 2016.*
>
> *The interveners concurred with Festival's understanding. OEB staff noted that while the settlement agreement did not explicitly address this issue it was not identified as an unsettled issue.*
>
> ***OEB Findings***
> *The OEB approves Festival's request to align its rate year to January 1."*

Festival is next scheduled to rebase for rates effective January 1, 2020.

Festival is requesting to defer the setting of its rates on a COS basis until January 1, 2021 and continue on the Price Cap IR stream for rates effective January 1, 2020. This request is based on several financial and non-financial factors as documented below.

Corporate Governance

Festival follows corporate governance best practices. Festival's Board of Directors is skills based with a range of experience including utility management, utility regulation, corporate governance, and human resources. Of Festival's 8-member Board, 5 members are independent. The Board consists of several committees including Finance & Audit, Human Resources, and Risk.

We note that our Board of Directors is comprised of 3 members of council for the City of Stratford. Municipal elections are currently scheduled for October 22, 2018 and it may be there are changes to the composition of the Board of Directors as a result of such election. A deferral would permit additional time for any new board members to be better informed of the application.

Scorecard Results

Since the last rebasing, Festival has had consistently strong scorecard results. The table below includes the deemed ROE since Festival's last rebasing compared to the actual ROE.

Note that the 2015 reported achieved ROE over earnings was explained in the RRR filing 2.1.5.6 for that year indicating that it was the result of the regulated disposition of the ICM variance account #1508 for the transformer station as part of the 2015 COS application as well as the approval by the OEB of an additional ICM rate rider for the 7-month period ending December 31, 2015. The ROE in 2015 without these regulated adjustments would've been within the 300 basis points of Festival's deemed ROE.

	Deemed ROE	**Achieved ROE**
2012	9.85%	9.75%
2013	9.85%	10.5%
2014	9.85%	8.18%
2015	9.3%	14.24%
2016	9.3%	7.37%

The reliability stats included in Festival's scorecard are within the regulated thresholds and are included in the table below for reference. Festival's SAIDI and SAIFI stats are well below the provincial averages (our customers experience on average fewer hours of interrupted power and fewer occurrences where power is interrupted).

	SAIDI	SAIFI
2012	1.04	1.42
2013	1.34	1.73
2014	0.65	1.05
2015	1.02	1.21
2016	1.32	0.93

Festival has achieved a category 4 efficiency assessment via the PEG benchmarking analysis. As explained in the last rebasing application, Festival's previous investment in capital infrastructure has been the main driver of this efficiency ranking. Prior to the PEG report, Festival achieved the higher efficiency ratings as the previous rating was based on OM&A costs only, which have historically been maintained reasonably by Festival. In fact, the 2016 utility yearbook recently released shows that Festival continues to maintain lower OM&A costs per customer in comparison to many other utilities (Festival would be in the second quartile when comparing OM&A cost per customer as per the 2016 yearbook).

In Festival's 2015 COS application, Festival indicated that based on budgets and projections, the total cost performance results under PEG were expected to decrease each year, gradually moving Festival to an improved category ranking. The PEG statistics for Festival are included in the table below and show how Festival is achieving this reduction as planned:

	Cost Performance Results
2013	19.6%
2014	16.6%
2015	14.0%
2016	13.4%

Festival would note that other than a singular customer issue, see below, that has arisen the customer growth is steady at approximately 1%, in-line with the previous forecast provided in EB-2014-0073 as are capital and OM&A spending.

Significant New Customer

While growth has been consistent, there is a singular significant issue that has arisen. Early in 2018 Festival expects to connect a new large customer to Festival's distribution system. As such, Festival will be servicing a customer who is participating in a pilot project with the IESO under a three year contract. This customer is forecasted to provide significant distribution revenues to Festival during the 3 year contract term.

Festival is uncertain at this time if the contract will be renewed with the IESO for 2021 and for what term, or if it will be cancelled after the initial term. If required to file for rates effective January 1, 2020, Festival would need to begin preparation of its evidence in spring 2018. Further, the future of the customer's contract with the IESO would not likely be clear and given the very recent connection Festival will have a very limited amount of operational experience with this customer. However, if the deferral is granted, Festival would begin preparing a January 1, 2021 filing early in 2019, at which point we expect to have additional information about any potential renewal or cancellation of the contract this customer holds with the IESO and the operational impact on Festival's distribution system.

The uncertainty regarding this customer after 2020 is a significant factor in Festival's decision to request a deferral of the COS filing until 2021.

Existing Rates

Festival's existing rates, if increased by the Price Cap IR formula for 2020, are sufficient to maintain the safe, reliable and high-quality service our customers expect. Festival feels that incurring the expense required to file a COS application would not be prudent given all of the elements highlighted above, as well as Festival's ability to maintain service with a Price Cap increase in 2020.

Due to the reasons noted above, Festival requests a deferral of its next scheduled COS to January 1, 2021.

Should the board have any questions regarding this request, please contact me at the number noted below or by email at kmccann@festivalhydro.com.

Yours truly,
Festival Hydro Inc.
ORIGINAL SIGNED BY K. McCann

K. McCann, CPA, CA
Tel (519) 271–4703 x. 221

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Ontario

BY E-MAIL

November 16, 2018

K. McCann
Chief Financial Officer
Festival Hydro Inc.
P.O. Box 397
Stratford, ON N5A 6T5

Dear Ms. McCann:

Re: Application for 2020 Electricity Distribution Rates

This letter is in response to your letter expressing an interest to defer Festival Hydro Inc.'s (Festival Hydro) rebasing of its rates beyond the 2020 rate year.

The Ontario Energy Board (OEB) has reviewed your letter, as well as Festival Hydro's financial and non-financial scorecard performance from 2012 to 2017. Based on this review, the OEB has concluded that it will not require Festival Hydro's 2020 rates to be set on a cost of service basis. This decision is based on information up to 2017. The OEB will monitor Festival Hydro's performance and may re-assess this decision once 2018 information is available. In the meantime, the OEB will place Festival Hydro on the list of distributors whose rates will be scheduled for rebasing for the 2021 rate year.

If Festival Hydro intends to seek a rate adjustment for 2020 rates, the OEB expects Festival Hydro to adhere to the process for Price Cap Incentive Rate-setting applications for the 2020 rate year.

If Festival Hydro subsequently seeks a further deferral the OEB will consider whether the Annual Incentive Rate-setting Index method that was developed for distributors intending longer periods without rebasing should be applied. The OEB will also consider whether the filing of a distribution system plan would be required at that time.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Festival Hydro INC.

P.O. Box 397, Stratford, Ontario N5A 6T5

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February 1, 2019

BY RESS & COURIER

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Festival Hydro Inc. – ED-2002-0513
2021 Cost of Service ("COS") Application Deferral Request

Dear Ms. Walli,

Festival's last COS application (EB-2014-0073) was filed for rates effective January 1, 2015, however the Decision and Order and Final rate order were not received until May 28, 2015 and June 4, 2015 respectively and as such the Decision and Order indicated:

> *"Festival confirmed its request for a rate year alignment to January 1 in its draft rate order. Festival noted that although the effective date of the Decision and Order for 2015 rates is May 1, 2015, it is Festival's understanding that its rate year is now aligned with the fiscal year and that its next IRM application will be filed for rates effective January 1, 2016.*
>
> *The interveners concurred with Festival's understanding. OEB staff noted that while the settlement agreement did not explicitly address this issue it was not identified as an unsettled issue.*
>
> *OEB Findings*
> *The OEB approves Festival's request to align its rate year to January 1."*

On November 16th, 2018, Festival received approval to defer their next scheduled rebasing from January 1, 2020 to January 2, 2021.

Festival is requesting to further defer the setting of its rates on a COS basis until January 1, 2022 and continue on the Price Cap IR stream for rates effective January 1, 2021. This request is based on several financial and non-financial factors as documented below. Festival views the deferral as appropriate for ratepayers, Festival, and will make a better use of Board resources.

Corporate Governance

Festival follows corporate governance best practices. Festival's Board of Directors is skills based with a range of experience including utility management, utility regulation, corporate governance, and human resources. Of Festival's 8-member Board, 3 members are independent. The Board consists of several committees including Finance & Audit, Human Resources, and Risk.

Scorecard Results

Since the last rebasing, Festival has had consistently strong scorecard results. The table below includes the deemed ROE since Festival's last rebasing compared to the actual ROE.

Note that the 2015 reported achieved ROE over earnings was explained in the RRR filing 2.1.5.6 for that year indicating that it was the result of the regulated disposition of the ICM variance account #1508 for the transformer station as part of the 2015 COS application as well as the approval by the OEB of an additional ICM rate rider for the 7-month period ending December 31, 2015. The ROE in 2015 without these regulated adjustments would've been within the 300 basis points of Festival's deemed ROE.

	Deemed ROE	Achieved ROE
2013	9.85%	10.5%
2014	9.85%	8.18%
2015	9.3%	14.24%
2016	9.3%	7.37%
2017	9.3%	8.43%

The reliability stats included in Festival's scorecard are within the regulated thresholds and are included in the table below for reference. Festival's SAIDI and SAIFI stats are well below the industry averages (our customers experience on average fewer hours of interrupted power and fewer occurrences where power is interrupted). Note that these figures are adjusted for loss of supply and major events.

	Festival SAIDI	Industry Avg. SAIDI	Festival SAIFI	Industry Avg. SAIFI
2013	1.34	2.56	1.73	1.55
2014	0.65	2.74	1.05	1.57
2015	1.02	2.77	1.21	1.57
2016	1.32	2.79	0.93	1.48
2017	1.69	2.85	1.92	1.44
5 Yr Avg	1.20	2.74	1.37	1.52

Festival has achieved a category 4 efficiency assessment via the PEG benchmarking analysis. As explained in the last rebasing application, Festival's previous investment in capital infrastructure has been the main driver of this efficiency ranking. While the PEG report places Festival in the 4th category, Festival saw a decline in total cost per customer in 2017 and moved from the 34th lowest cost/customer in the province in 2016 at $645/customer to the 28th at $612/customer.

Prior to the PEG report, Festival achieved the higher efficiency ratings as the previous rating was based on OM&A costs only, which have historically been maintained reasonably by Festival. In fact, the recently released 2017 utility yearbook shows that Festival continues to maintain lower OM&A costs per customer in comparison to many other utilities (Festival would be in the second quartile when comparing OM&A cost per customer as per the 2017 yearbook).

In Festival's 2015 COS application, Festival indicated that based on budgets and projections, the total cost performance results under PEG were expected to decrease each year, gradually moving Festival to an improved category ranking. The PEG statistics for Festival are included in the table below and show how Festival is achieving this reduction as planned:

	Cost Performance Results
2013	19.6%
2014	16.6%
2015	14.0%
2016	13.4%
2017	8.8%

Festival would note that other than a singular customer issue, see below, customer growth is steady at approximately 1%, in-line with the previous forecast provided in EB-2014-0073 as are capital and OM&A spending.

Significant New Customer

While growth has been consistent, there is a singular significant issue that has arisen. In 2018, Festival connected a new large customer, a battery storage customer, to our distribution system. This customer is participating in a pilot project with the IESO under a three-year contract. This customer is forecasted to provide significant distribution revenues to Festival during the 3-year contract term. Festival understands the three-year period will end in 2021.

The customer is not in a position to make any commitments beyond the three-year period at this time or in the next several months. As such, Festival is uncertain at this time if the contract will be renewed with the IESO for 2021 and for what term, or if it will be cancelled after the initial term. If required to file for rates effective January 1, 2021, Festival would need to begin preparation of its evidence in spring 2019. The future of the customer's contract with the IESO would not likely be clear at that point which would provide significant uncertainty in the forecast. However, if the deferral is granted, Festival would begin preparing a January 1, 2022 filing early in 2020 for filing with the OEB by April of 2021, at which point we would have sufficient knowledge to properly reflect the operational impact of this customer on Festival's distribution system.

Existing Rates

Festival's existing rates, if increased by the Price Cap IR formula for 2021, are sufficient to maintain the safe, reliable and high-quality service our customers expect. Festival submits that incurring the expense required to file a COS application would not be prudent given all of the elements highlighted above, as well as Festival's ability to maintain service with a Price Cap increase in 2021.

Due to the reasons noted above, Festival requests a deferral of its next scheduled COS to January 1, 2022.

Should the board have any questions regarding this request, please contact me at the number noted below or by email at kmccann@festivalhydro.com.

Yours truly,
Festival Hydro Inc.

Kelly McCann

K. McCann, CPA, CA
Tel (519) 271–4703 x. 221

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL

May 13, 2019

Kelly McCann
Chief Financial Officer
Festival Hydro Inc.
187 Erie Street
P.O. Box 397
Stratford, N5A 6T5
kmccann@festivalhydro.com

Dear Ms. McCann:

Re: Application for 2021 Electricity Rates

This letter is in response to your letter expressing an interest to defer Festival Hydro Inc.'s (Festival Hydro) rebasing of its rates beyond the 2021 rate year.

On November 16, 2018 the OEB granted Festival Hydro's request to defer its rebasing application for 2020 rates. This was based on a review of Festival Hydro's performance from 2013 to 2017. Performance for 2018 was not filed with the OEB until April 30, 2019 and has not yet been reviewed by the OEB. Provided that no concerns are raised through the OEB's review of the 2018 performance and a forecast of the 2019 performance, which will be requested in early 2020, the OEB will not require Festival Hydro to set its 2021 rates on a cost of service basis.

This is the second year that Festival Hydro has sought a deferral to filing a cost of service rate application. If Festival Hydro subsequently seeks a further deferral the OEB will consider whether the Annual Incentive Rate-setting Index method that was developed for distributors intending longer periods without rebasing should be applied. The OEB will also consider whether the filing of a distribution system plan would be required at that time.

If Festival Power intends to seek a rate adjustment for 2020 and 2021 rates, the OEB expects Festival Power to adhere to the process for Price Cap Incentive Rate-setting applications for the 2020 and 2021 rate years.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Festival Hydro INC

P.O. Box 397, Stratford, Ontario N5A 6T5

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November 30, 2020

BY RESS & COURIER

Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Festival Hydro Inc. – ED-2002-0513
2022 Cost of Service ("COS") Application Deferral Request

Festival's last COS application (EB-2014-0073) was filed for rates effective January 1, 2015, however the Decision and Order and Final rate order were not received until May 28, 2015 and June 4, 2015 respectively and as such the Decision and Order indicated:

> *"Festival confirmed its request for a rate year alignment to January 1 in its draft rate order. Festival noted that although the effective date of the Decision and Order for 2015 rates is May 1, 2015, it is Festival's understanding that its rate year is now aligned with the fiscal year and that its next IRM application will be filed for rates effective January 1, 2016.*
>
> *The interveners concurred with Festival's understanding. OEB staff noted that while the settlement agreement did not explicitly address this issue it was not identified as an unsettled issue.*
>
> *OEB Findings*
> *The OEB approves Festival's request to align its rate year to January 1."*

On April 29, 2020, Festival received approval to defer their next scheduled rebasing from January 1, 2021 to January 1, 2022.

Festival is requesting to further defer the setting of its rates on a COS basis until January 1, 2023 and continue on the Price Cap IR stream for rates effective January 1, 2022. This request is based on several financial and non-financial factors as documented below. Festival views the deferral as appropriate for ratepayers, Festival, and will make better use of Board resources.

Corporate Governance

Festival follows corporate governance best practices as per OEB Report EB-2014-0255. Festival's Board of Directors is skills based with a range of experience including utility management, utility regulation, corporate governance, and human resources. Of Festival's 8-member Board, 3 members are independent. The Board consists of several committees including Finance & Audit, Human Resources, and Risk.

Scorecard Results

Since the last rebasing, Festival has had consistently strong scorecard results. The table below includes the deemed ROE since Festival's last rebasing compared to the actual ROE.

Note that the 2015 reported achieved ROE over earnings was explained in the RRR filing 2.1.5.6 for that year indicating that it was the result of the regulated disposition of the ICM variance account #1508 for the transformer station as part of the 2015 COS application as well as the approval by the OEB of an additional ICM rate rider for the 7-month period ending December 31, 2015. The ROE in 2015 without these regulated adjustments would've been within the 300 basis points of Festival's deemed ROE.

	Deemed ROE	Achieved ROE
2015	9.3%	14.24%
2016	9.3%	7.37%
2017	9.3%	8.43%
2018	9.3%	8.3%
2019	9.3%	9.1%

The reliability stats included in Festival's scorecard are within the regulated thresholds and are included in the table below for reference. Festival's SAIDI and SAIFI stats are below the industry averages (our customers experience on average fewer hours of interrupted power and fewer occurrences where power is interrupted). Note that these figures are adjusted for loss of supply and major events.

	Festival SAIDI	Industry Avg. SAIDI	Festival SAIFI	Industry Avg. SAIFI
2015	1.02	2.77	1.21	1.57
2016	1.32	2.79	0.93	1.48
2017	1.69	2.85	1.92	1.44
2018	0.92	2.59	0.73	1.48
2019	1.79	2.64	1.78	1.52
5 Yr Avg	1.35	2.73	1.31	1.50

Festival has achieved a category 3 efficiency assessment via the PEG benchmarking analysis effective for 2021 rates. As explained in the last rebasing application, Festival's previous investment in capital infrastructure has been the main driver of this efficiency ranking and as predicted in that rate application based on future costing projection, Festival has shifted into the third efficiency ranking. Of note, a significant capital component is related to the construction of the Transformer Station which was justified on an overall benefit to customers through reduced transmission payments which is not incorporated into the efficiency rating.

Prior to the PEG report, Festival achieved the higher efficiency ratings as the previous rating was based on OM&A costs only, which have historically been maintained reasonably by Festival. In fact, the recently released 2019 utility yearbook shows that Festival continues to maintain lower OM&A costs per customer in comparison to many other utilities (Festival would be in the second quartile when comparing OM&A cost per customer as per the 2019 yearbook).

In Festival's 2015 COS application, Festival indicated that based on budgets and projections, the total cost performance results under PEG were expected to decrease each year, gradually moving Festival to an improved category ranking. The PEG statistics for Festival are included in the table below and show how Festival is achieving this reduction as planned:

	Cost Performance Results
2013	19.6%
2014	16.6%
2015	14.0%
2016	13.4%
2017	8.8%
2018	10.8%
2019	5.9%

COVID-19

Festival notes that the COVID-19 pandemic is ongoing, making it more difficult than normal to plan activities. Festival has been managing throughout the last several months to ensure the continued safe and reliable distribution service and work environment. Recent announcements would imply that a more normal situation will return later on in 2021 making the preparation of a rebasing application more manageable.

Existing Rates

Festival's existing rates, if increased by the Price Cap IR formula for 2022, are sufficient to maintain the safe, reliable and high-quality service our customers expect. Festival submits that incurring the expense required to file a COS application would not be prudent given all of the elements highlighted above, as well as Festival's ability to maintain service with a Price Cap increase in 2022.

Due to the reasons noted above, Festival requests a deferral of its next scheduled COS to January 1, 2023.

Should the board have any questions regarding this request, please contact me at the number noted below or by email at sknapman@festivalhydro.com

Yours truly,
Festival Hydro Inc.

S. Knapman
Tel (519) 271–4700 x. 259

BY EMAIL

March 31, 2021

Scott Knapman
Chief Executive Officer
Festival Hydro Inc.
P.O. Box 397
Stratford, ON N5A 6T5
sknapman@festivalhydro.com

Dear Mr. Knapman:

Re: Application for 2022 Electricity Rates
OEB File No. EB-2021-0024

This letter is in response to your November 30, 2020 letter expressing an interest to defer Festival Hydro Inc.'s (Festival Hydro) rebasing of its rates beyond the 2022 rate year.

The OEB has reviewed the letter and based on Festival Hydro's 2019 performance and the continuing impact of COVID-19, the OEB is granting approval for Festival Hydro's request to defer its 2022 cost of service application.

Festival Hydro did not indicate that its request is reliant upon the availability of an Incremental Capital Module (ICM), as such the OEB expects that Festival Hydro will not file an ICM for the 2022 rate year.

This is the third consecutive year that Festival Hydro has sought a deferral to filing a cost of service rate application. The Annual Incentive Rate-setting Index (Annual IR Index) is the method that was developed for distributors intending longer periods without rebasing. Therefore, in the absence of a 2023 cost of service rate application from Festival Hydro, the OEB will move Festival Hydro from the Price Cap Rate-setting Index method to the Annual IR Index method.

If Festival Hydro intends to seek a rate adjustment for 2022 rates, the OEB expects Festival Hydro to adhere to the process for Price Cap Incentive Rate-setting applications for the 2022 rate year.

The OEB will be reviewing how deferrals are granted in the future, which may have an impact on the options available to distributors seeking subsequent deferral(s). The review will consider the availability of Incremental Capital Module, filing of a Distribution System Plan, and whether distributors would be moved from the Price Cap Incentive Rate-setting method to the Annual Incentive Rate-setting Index method for any deferral request.

Yours truly,

Original Signed By

Christine E. Long
Registrar

P.O. Box 397, Stratford, Ontario N5A 6T5

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January 18, 2022

BY RESS & COURIER

Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Festival Hydro Inc. – ED-2002-0513
2023 and 2024 Cost of Service ("COS") Application Deferral Request

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Festival's last Cost of Service Application (EB-2014-0073) was filed for rates effective January 1, 2015, however the Decision and Order and Final rate order were not received until May 28, 2015 and June 4, 2015 respectively and as such the Decision and Order indicated:

> *"Festival confirmed its request for a rate year alignment to January 1 in its draft rate order. Festival noted that although the effective date of the Decision and Order for 2015 rates is May 1, 2015, it is Festival's understanding that its rate year is now aligned with the fiscal year and that its next IRM application will be filed for rates effective January 1, 2016.*
>
> *The interveners concurred with Festival's understanding. OEB staff noted that while the settlement agreement did not explicitly address this issue it was not identified as an unsettled issue.*
>
> ***OEB Findings***
> *The OEB approves Festival's request to align its rate year to January 1."*

On March 31, 2021, Festival received approval to defer their next scheduled rebasing from January 1, 2022 to January 1, 2023. It was noted that in the absence of a 2023 COS Application from Festival Hydro, the OEB will move Festival Hydro from the Price Cap Rate-setting Index method to the Annual IR Index method. However, on December 1, 2021, the OEB delivered a letter inviting interested distributors to submit expressions of interest to defer to a later year up to 2025.

Festival is requesting to further defer the setting of its rates on a COS basis until January 1, 2025 and is requesting an extension to the change to the Annual IR Index method, by maintaining the Price Cap Rate-setting Index method for rates effective January 1, 2023 and January 1, 2024. The extension to the change in Annual IR is based on the OEB request to defer. While this is the preferred option, Festival will accept the Annual IR Index method and is still requesting a deferral for 2023 and 2024 rates with the intent to file a COS Application for rates effective January 1, 2025. This request is based on several financial and non-financial factors as documented below. Festival views the deferral as appropriate for customers, Festival, and will make better use of Board resources.

Corporate Governance

Festival follows corporate governance best practices as per OEB Report EB-2014-0255. Festival's Board of Directors is skills based with a range of experience including utility management, utility regulation, corporate governance, and human resources. Of Festival's 8-member Board, 3 members are independent. The Board consists of several committees including Audit, Human Resources, and Risk.

Scorecard Results

Since the last rebasing, Festival has had consistently strong scorecard results. The table below includes the deemed ROE since Festival's last rebasing compared to the actual ROE.

Note that the 2015 reported achieved ROE over earnings was explained in the RRR filing 2.1.5.6 for that year indicating that it was the result of the regulated disposition of the ICM variance account #1508 for the transformer station as part of the 2015 COS Application as well as the approval by the OEB of an additional ICM rate rider for the 7-month period ending December 31, 2015. The ROE in 2015 without these regulated adjustments would've been within the 300 basis points of Festival's deemed ROE.

	Deemed ROE	Achieved ROE
2015	9.3%	14.24%
2016	9.3%	7.37%
2017	9.3%	8.43%
2018	9.3%	8.3%
2019	9.3%	9.1%
2020	9.3%	8.89%

The reliability stats included in Festival's scorecard are within the regulated thresholds and are included in the table below for reference. Festival's SAIDI and SAIFI stats are below the industry averages (our customers experience on average fewer hours of interrupted power and fewer occurrences where power is interrupted). Note that these figures are adjusted for loss of supply and major events.

	Festival SAIDI	Industry Avg. SAIDI	Festival SAIFI	Industry Avg. SAIFI
2015	1.02	2.77	1.21	1.57
2016	1.32	2.79	0.93	1.48
2017	1.69	2.85	1.92	1.44
2018	0.92	2.59	0.73	1.48
2019	1.79	2.64	1.78	1.52
2020	1.27	2.72	1.00	1.56

Festival has achieved a category 3 efficiency assessment via the PEG benchmarking analysis effective for both 2021 and 2022 rates. As explained in the last COS Application, Festival's previous investment in capital infrastructure has been the main driver of this efficiency ranking and as predicted in that rate application based on future costing projection, Festival has shifted into the third efficiency ranking. Of note, a significant capital component is related to the construction of the Transformer Station which was justified on an overall benefit to customers through reduced transmission payments which is not incorporated into the efficiency rating.

Prior to the PEG report, Festival achieved the higher efficiency ratings as the previous rating was based on OM&A costs only, which have historically been maintained reasonably by Festival. In fact, the recently released 2020 utility yearbook shows that Festival continues to maintain lower OM&A costs per customer in comparison to many other utilities.

COVID-19 and Management Changes

Festival notes that the COVID-19 pandemic is ongoing, making it more difficult than normal to plan and manage activities. Festival has been managing throughout the last 22 months to ensure the continued safe and reliable distribution service and work environment. Due to the ongoing pandemic, resourcing is limited and requires deferral until stability can be maintained. In addition, over the past year there have been several changes to executive level positions at Festival Hydro. High levels of service have been maintained, however, due to these changes, filing a COS Application would further strain resources and could impact service quality.

New Filing Requirements

On December 16, 2021, the OEB released an updated version of its Filing Requirements for Electricity Distribution Rate Applications (Filing Requirements) for small electricity distributors. The threshold for small electricity distributors changed from less than 20,000 customers to less than 30,000 customers. Festival Hydro would now fall under these new requirements and Festival Hydro would like to ensure it can properly address and adapt to the change in requirements for its next COS Application.

Existing Rates

Festival's existing rates, if increased by the Price Cap Rate-setting Index or the Annual IR Index formula for 2023 and 2024, are sufficient to maintain the safe, reliable and high-quality service our customers expect. Festival submits that incurring the expense required to file a COS Application would not be prudent given all of the elements highlighted above, as well as Festival's ability to maintain service with a Price Cap Rate-setting Index or an Annual IR Index formula increase in 2023 and 2024.

Due to the reasons noted above, Festival requests a deferral of its next scheduled COS to January 1, 2025.

Should the board have any questions regarding this request, please contact me at the number noted below or by email at aconrad@festivalhydro.com.

Thank you,
Festival Hydro Inc.

A. Conrad
Tel (519) 271–4700 x. 221

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

March 9, 2022

Alyson Conrad, Chief Financial Officer
Festival Hydro Inc.
P.O. Box 397
Stratford ON N5A 6T5
Email: aconrad@festivalhydro.com

Dear Ms. Conrad:

Re: Application for 2023 Electricity Rates
OEB File No. EB-2022-0032 Festival Hydro Inc.

This letter is in response to your letter expressing an interest to defer Festival Hydro's rebasing of its rates for the 2023 rate year for two years.

The OEB's letter of December 1, 2021, regarding changes to the OEB's approach to deferrals, outlined distributors with existing deferrals, such as Festival Hydro, can request one more deferral but only to a combined maximum of three years or can select Annual Incentive Rate-setting Index (Annual IR). Festival Hydro acknowledged that it has already reached the combined three-year limit and while it prefers to remain on the Price Cap Incentive Rate-setting method, it is prepared to accept Annual IR.

The OEB has reviewed the letter and Festival Hydro's recent financial and service quality performance and will not require Festival Hydro to rebase for 2023 rates. While the OEB acknowledges that it invited expressions of interest from electricity distributors to defer rebasing applications for 2023 rates, as per the OEB's December 1 letter, the OEB will place Festival Hydro on the Annual IR method given that it has already deferred rebasing for three consecutive years.

If Festival Hydro intends to seek a rate adjustment for 2023 rates, the OEB expects Festival Hydro to adhere to the process for Annual IR applications for the 2023 rate year.

The requirement to file a Distribution System Plan was waived in each of Festival Hydro's prior deferral approvals and the OEB will not require Festival Hydro to file a Distribution System Plan at this time.

Yours truly,

Nancy Marconi
Registrar

Attachment 14

2017 Mearie Salary Survey

The MEARIE Group

2017 Management Salary Survey
Of Local Distribution Companies

SURVEY REPORT

August 2017

SURVEY ADMINISTRATOR: Korn Ferry Hay Group

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Section

Appendices

1. Introduction

The MEARIE Group is pleased to present this report of the 2017 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, Local Distribution Companies (LDCs) are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's LDCs to assist you and in understanding the competitive landscape and support your efforts in developing pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey was further enhanced from 2013 to 2014 through our partnership with Korn Ferry Hay Group ("Hay Group"), a globally renowned compensation consulting firm. Hay Group drew upon their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world.

There are no substantial changes to the survey in from 2015 to 2017.

The 2017 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2017 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
  - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
  - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
  - All Organizations
  - Region
  - Customer Base
  - Revenue
  - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in support of your organization's compensation programs.

CONFIDENTIALITY POLICY

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey (a "Survey"), as well as Hay Group (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC's data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g. by geography or size).

All of the information obtained through a Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither Hay Group nor MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or Hay Group or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey may also be included in the Hay Group's Canadian compensation database. Information in the Hay Group database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed. As of May 2017, there are over 500 employers represented in the Hay Group database. Should you have any questions or for further information, please contact Felix Yu, analyst at Korn Ferry Hay Group at 647-798-3724 or felix.yu@kornferry.com.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of a Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests, or will co-operate with respect to any steps The MEARIE Group reasonably wishes to take, to contest or limit the scope of the disclosure.

The MEARIE Group will not be liable for breaches by participating LDCs or Hay Group of this Confidentiality Policy.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
	0006	Head of Human Resources
Administration	1000	Executive Assistant
	1001	Administrative Assistant
Engineering	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
	2003	Supervisor Engineering
Operations	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
	4005	Accountant
Customer Service	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants

All organizations in the LDC sector in Ontario were invited to participate in the survey. The following thirty-five (35) organizations submitted data:

- Bluewater Power Distribution
- Brantford Power Inc.
- Burlington Hydro
- Collus PowerStream
- E.L.K. Energy Inc.
- Energy+ Inc.
- Entegrus
- EnWin Utilities Ltd.
- Essex Power
- Festival Hydro Inc.
- Fort Frances Power Corporation
- Greater Sudbury Utilities
- Grimsby Power Inc.
- Guelph Hydro Electric Systems Inc.
- Halton Hills Hydro Inc.
- InnPower Corporation
- Kitchener-Wilmot Hydro Inc.
- Lakeland Power Distribution Ltd.
- London Hydro Inc.
- Milton Hydro Distribution Inc
- Newmarket-Tay Power Distribution Ltd.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Limited
- Northern Ontario Wires Inc.
- Oakville Enterprises Corporation
- Orangeville Hydro Ltd.
- Oshawa PUC Networks
- Peterborough Utilities Group
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston
- Veridian
- Wasaga Distribution Inc.
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.

Due to the changes in the participant mix, data values in the report can fluctuate from one year to another. Therefore, participants are reminded of these factors when comparing data from 2017 over 2016.

Participant Group Profile

All participants provided information regarding their organizational profile. The summary statistics of the participating organizations are detailed below.

The figures reported below are assessed on an "as provided" basis. Korn Ferry Hay Group and the MEARIE Group have not independently or exhaustively verified the values presented below.

Statistic	P25	P50	P75	Average
Annual Operating Budget ($ millions, less the cost of power)	6.9	12.0	25.0	18.8
Annual Operating Budget ($ millions, including the cost of power)	45.4	125.2	203.8	133
Number of Employees (full time equivalent)	33	59	131	84
Number of Customers	16,868	36,720	57,160	44,495
Gross Revenue ($ millions, less the cost of power)	10.1	18.8	34.3	27.2
Gross Revenue ($ millions, including the cost of power)	46.4	128.2	213.4	145.3
Regulated Gross Revenue	93%	99%	100%	93%
Unregulated Gross Revenue	0%	1%	7%	7%

All organizations noted the fiscal year ends in December.

Analyst Note: where average is significantly higher or lower than the median of the market, this indicates a small number of observations which skew the data either high or low. For example, unregulated gross revenue average is 7%, which is substantially higher than the 1% at median, indicating that within the top 25% of organizations there is a significant portion of unregulated Gross revenue in excess of 10% in a few organizations.

3. Salary Administration

Salary Range Adjustments – 2016, 2017, 2018

Thirty (30, or 86%) organizations reported data for salary ranges while 5 (14%) indicated they did not use ranges. The most common month for adjusting salary ranges is January (over 75% of reporting organizations).

In 2016, twenty-six (26) organizations reported adjustment to salary ranges, while four (4) organizations froze their ranges (i.e., provided 0%). Excluding the 4 organizations who froze ranges (i.e., provided 0%), the average range increase is 2.1%.

In 2017, twenty-five (25) organizations reported adjustment to salary ranges, while five (5) froze their ranges. Excluding the five (5) organizations that froze their ranges (i.e., provided 0%), the overall average salary range increase is 1.9%.

Survey participants report planning to adjust salary ranges in 2018 by an overall average of 2.1% (n=11).

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO	Executive	Director	Management	Professional /Technical	Admin	Overall
2016	1.8%	1.6%	1.6%	1.7%	1.5%	1.7%	2.1%
2017	1.9%	1.6%	1.7%	1.7%	1.6%	1.7%	1.9%
2018	2.0%	2.0%	2.0%	2.3%	2.0%	2.3%	2.1%

Base Salary Increases – 2016, 2017, 2018

The most common timing for adjusting salaries is January (over 50% of reporting organizations grant annual salary increases in that month).

Survey participants report adjusting actual salaries in 2016 by an overall average of 2.4% (n=34).

Survey participants report adjusting actual salaries in 2017 by an overall average of 2.3% (n=26).

For 2018, survey participants reported projected average salary increases of 2.2% (n=14).

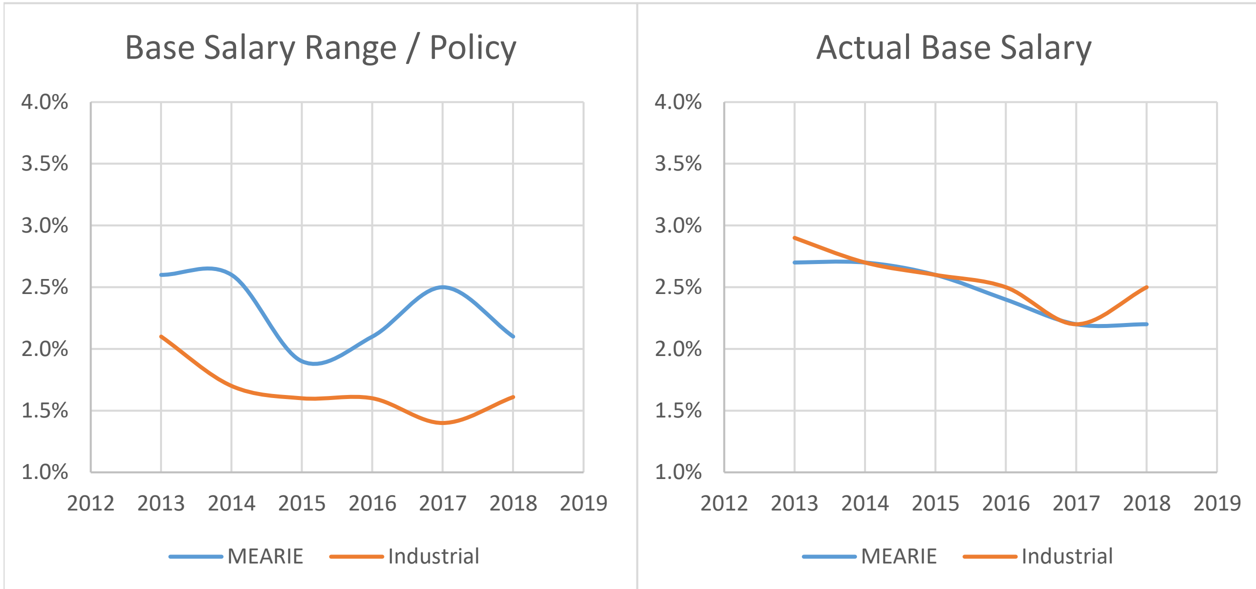
The base salary adjustments by employee level are noted in the table below.

Year	CEO	Executive	Director	Management	Professional /Technical	Admin	Overall
2016	3.3%	2.2%	2.3%	2.6%	2.3%	3.6%	2.7%
2017	2.2%	2.1%	2.6%	2.3%	2.2%	2.3%	2.3%
2018	2.2%	2.2%	2.2%	2.2%	2.3%	2.3%	2.2%

Salary Trends

Korn Ferry Hay Group compiles an annual compensation forecast survey across Canada, with over 500 participants annually.

The graph below depicts how the overall Canadian all-industrial organization market has tracked from a range and actual salary perspective versus The MEARIE Group Management Salary Survey trend information over the past 5 years.



Generally, local distribution companies track very close to the all-industrial market for actual salary adjustments; generally within 0.3 percentage points. Local distribution companies track above the all-industrial market for salary range adjustments by 0.3 – 1.1 percentage points, according to the preliminary 2018 all-industrial compensation planning update.

The differential between actual base salary increases and salary range adjustments among local distribution companies is generally small, this year the average differential is 0.1 percentage points. The average differential among industrial organizations is 0.9 percentage points.

This indicates that industrial organizations may be allocating greater portions of salary budgets to differentiation by merit, and enabling high performers to perhaps be paid above job rate and/or moving people through the range faster. That is, industrial organizations are likely increasing their overall compa-ratios, whereas LDCs are generally maintaining or movement through range is very conservative.

Incentive Programs

a. The majority of organizations (25 of 35 or 71%) indicated that they offer short term incentive pay to at least some of their employees.
- Sixteen (16) of the organizations indicated that all employee groups participated in STI.
- Nine (9) organizations have STI plans for designated senior management and/or executives that do not extend to non-management staff.

b. Twenty (20) of the twenty-five (25) organizations who offer short term incentive pay provided information about their incentive plans. The determination of individual bonus payments is based on the weighting of performance factors such as corporate versus individual versus team/department performance.
Typical plan mix is a combination of corporate and individual metrics with a heavier weighting on corporate for senior management and/or executives and a heavier weighting on individual metrics for non-management staff. For example:
- The most common CEO incentive plan is 80% Corporate, 20% Individual
- The most common Director plan is 60% Corporate, 40% Individual
- The most common Admin plan is 0% Corporate and 100% Individual

The average plan mix, by employee level, is provided in the table below.

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	66.1%	60.1%	66.3%	47.4%	52.7%	48.8%
Team / Department	1.9%	3.6%	2.5%	9.9%	0.0%	0.0%
Individual	31.9%	36.4%	31.3%	42.8%	47.3%	51.3%

Incentive Programs (continued)

Threshold Bonus Payouts

Formulaic or "target based" bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonus; pay out levels typically then increase as performance/results increase, up to a "target" bonus rate when performance goals have been "met".

Sixteen (16) of the twenty-five (25) organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of "target" bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance (i.e., how much targets are exceeded by), is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 100% of target.

Maximum Bonus Payout %	CEO (n =16)	Executive (n =14)	Director (n =11)	Management (n =14)	Professional / Technical (n = 10)	Admin. (n =10)
Average	1.1	1.1	1.2	1.2	1.2	1.2

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

Salary Compression Policy

Organizations were asked if they have any formal salary compression policy in place.

Thirty-three (33) of the thirty-five (35) organizations responded to this question.

Out of the thirty-three (33) responses, one (1) organization reported having a formal salary compression policy in place; two (2) organizations reported they either have an informal plan in place, or have been monitoring salary compression. Given that only two organizations responded to this question, there is insufficient data to report any details regarding compression and related policies.

4. Benefit Policies

Car Benefit

The majority of organizations (28 of 35 or 80%) provide a car benefit to some level of employee.

The table below summarizes the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance (monthly)
CEO	P75	*	*	825
	P50	41,250	*	725
	P25	*	*	594
	Average	43,819	*	727
	Number	4	2	20
Executive / VP	P75	*	*	725
	P50	*	*	600
	P25	*	*	425
	Average	*	*	580
	Number	2	2	11
Sr. Management / Director	P75	*	*	625
	P50	*	*	588
	P25	*	*	438
	Average	*	*	547
	Number	0	0	8

Two (2) organizations reported providing a car benefit to specified positions below Senior Management. These are in the form of a vehicle allowance.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 32	Mileage Reimbursement (¢ per km)
P75	54
P50	54
P25	50
Average	52

The most frequently reported mileage rate (13 organizations) is 54 cents per kilometer; the next most frequent reported rates are 48, 50, or 52 cents per kilometer (3 organizations each).

Perquisites

Club Memberships – Fitness

Sixteen (16) organizations reported providing a subsidy for fitness club fees. The typical policy is to provide a reimbursement of a fixed dollar amount per year. For all organizations, the same policy and maximum reimbursement applies regardless of job level.

N = 17	Maximum Reimbursement per year
P75	300
P50	200
P25	150
Average	229

Club Memberships – Social

One (1) organization reported having a separate policy / program for reimbursement of social club fees.

Perquisites (cont'd)

Health Spending Account

Nine (9) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the nine (9) organizations, four (4) provide the same funding for all jobs levels while five (5) differentiates by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	2,000	2000	1000	750	*
P50	550	475	475	450	375
P25	450	413	338	300	*
Average	1056	1050	600	536	454
Number	9	8	8	7	6

2nd Opinion Medical Advice

Four (4) organizations in the survey reported having a separate policy/program for this benefit.

Personal Financial/Legal Counseling

Three (3) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees. One (1) of these organizations reported a maximum dollar value.

Executive Medical Plan

Three (3) organizations reported providing enhanced medical coverage for executive levels only. Two (2) organizations reported a maximum dollar value in executive medical plan coverage.

Perquisites (cont'd)

Personal Computer / Cell Phone / Internet

Eleven (11) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only).
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place).
- Cash allowance intended to cover cell phone and/or internet service.

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices.

Other Perquisites

Other programs/practices reported, by seven (7) organizations, include:

- Reimbursement of dues/fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA).
- Provision of a personal spending account taxable benefit

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs?

Seventeen (15) organizations provided information about their basic/standard life insurance coverage where the typical coverage is 1.5x annual salary (average coverage of 1.66x). Enhanced benefits are provided by six (6) organizations, where senior roles receive coverage at an average of 1.95x annual salary.

Vacation Entitlement

All thirty-five (35) organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks of vacation.

The table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	*No range*	*Start* - 6	*Start* - 15	*Start* - 18	start - 28
Average	*Start*	2	7	14	21
Typical	*Start*	3	9	16	25
sample	n = 10	n = 20	n = 26	n = 28	n = 30
Executive / VP Level					
Range	*No range*	*Start* - 4	*Start* - 10	start - 18	2 - 28
Average	*Start*	2	7	14	22
Typical	*Start*	3	9	16	25
sample	n = 10	n = 19	n = 24	n = 27	n = 27
Director Level					
Range	*No range*	*Start* - 6	*Start* -15	2 - 18	9 - 28
Average	*Start*	2	7	14	22
Typical	*Start*	3	9	17	25
sample	n = 10	n = 22	n = 28	n = 28	n = 28
Manager Level					
Range	*No range*	*Start* - 4	3 - 10	8 - 18	15 - 28
Average	*Start*	2	7	15	23
Typical	*Start*	*Start*	9	17	25
sample	n = 12	n = 26	n = 31	n = 31	n = 30
Professional Level					
Range	*No range*	*Start* - 6	3 – 15	8 - 18	15 - 28
Average	*Start*	3	8	15	23
Typical	*Start*	3	9	16	25
sample	n = 13	n = 27	n = 30	n = 31	n = 31

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	1	3%
Any/All unused vacation entitlement may be carried-over with no restrictions.	3	9%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	14	40%
A maximum amount of unused vacation may be carried over.	16	46%
No unused vacation may be carried over	1	3%
Total	35	100%

Maximum Number of Days to Carry Over (n = 16)	Number of Days
Range	3 – 14
Average	6.9
Typical	5

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	9
One Year	8
Six Months or less	15
Total	32

Note:

Some organizations reported variations to the above policies such as:

- A maximum amount of days that can be carried over specified it as either one year entitlement or a portion of the year's entitlement. Four (4) of the sixteen (16) organizations reported this type of policy..
- Cash out policies where some vacation time may be paid out instead of being carried over.
- Carry-over policies that vary by vacation eligibility, for example, a maximum of 10 days can be carried over if the incumbent is eligible for up to 3 weeks of vacation; a maximum of 20 days may be carried over if the vacation eligibility is 4 weeks or more.

Educational Assistance / Reimbursement

Twenty participating organizations (20) provided details with regard to education assistance/ reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of programs and reimbursement rates. Key highlights are provided below:

- Seventeen (17) organizations stated that they offer education assistance/reimbursement; though typically there are limits such as education or training courses which must be job related, and are subject to managerial approval.
- Three (3) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Four (4) organizations provided an annual reimbursement maximum, the maximum depends on the level of study, and/or cost of education, less a deductible where applicable.
- Three (3) organizations provided a per-program reimbursement maximum, the mean of such maximum is $18,333.
- Payback provisions were provided by eleven (11) organizations. The average time to not trigger any pay back provision is 2.8 years, the median is 3.0 years. The range of time is between 90 days to 5 years. Eight (8) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, from completion of program, if the employee resigns within 12 months, they are liable for 100% of the cost; if the employee resigns between 12 and 24 months from the completion of education, they are liable for 75% of the cost.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect "All Ontario" data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying "Addendum".

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in the Excel files accompanying this report.

ALL ORGANIZATIONS

Code	Survey Job Title	Job Matches: Sample Statistic			Compensation Design: Salary Range Minimum	Job Rate	Salary Range Maximum	Target Bonus %	Total Cash Design		Actual Base Salary		Actual Bonus %	Actual Total Cash	
		# Orgs	# Incs	Hay Points P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
0000	President & CEO	30	33	1292	172,000	193,200	206,700	25%	221,000	234,200	195,500	208,500	20%	222,800	243,400
0001	Chief Operating Officer (COO)	15	16	872	135,400	148,000	160,900	15%	158,500	170,300	158,200	158,800	14%	170,700	179,200
0002	Head of Operations and/or Engineering	18	21	904	127,000	149,500	161,800	20%	176,500	168,000	154,200	151,200	19%	172,400	166,200
0003	CFO / Head of Finance	30	32	830	135,900	149,500	158,300	18%	152,900	170,800	156,800	156,300	18%	160,000	170,900
0004	Head of Customer Service	8	8	769	110,300	129,800	149,200	*	145,700	153,500	127,100	138,700	16%	136,200	154,100
0005	Head of Regulatory Affairs	6	6	771	141,500	161,100	172,000	20%	183,300	176,100	166,800	160,000	21%	184,000	181,400
0006	Head of Human Resources	13	13	800	120,900	134,900	148,000	18%	145,700	156,800	144,600	146,500	19%	158,000	164,600
1000	Executive Assistant	24	30	245	61,600	73,800	79,800	5%	74,900	75,600	75,700	75,900	4%	77,900	77,300
1001	Administrative Assistant	12	23	198	55,400	63,600	68,200	2%	64,000	64,900	67,100	67,700	2%	66,400	67,400
2000	Director Engineering	10	10	702	109,900	137,200	148,400	10%	146,000	143,200	136,800	136,300	7%	145,300	142,600
2001	Engineering Manager and/or Distribution Engineer	18	19	571	94,200	106,400	116,900	7%	110,600	117,000	110,700	115,200	6%	114,000	121,000
2002	Project Engineer	12	14	458	81,400	100,800	106,800	6%	101,100	96,700	102,200	94,800	5%	107,800	96,500
2003	Supervisor Engineering	15	18	451	87,500	101,700	109,300	7%	107,700	106,400	105,500	100,900	4%	105,900	105,200
2500	Director Operations	10	12	732	109,900	125,300	143,100	15%	143,800	139,200	134,900	133,000	13%	143,900	139,400
2501	Manager Operations	21	24	516	98,800	113,900	123,300	5%	118,400	118,100	116,000	119,900	4%	120,300	123,000
2502	Manager Control Centre	5	7	516	101,800	115,000	126,500	*	122,500	118,000	121,600	130,100	*	134,400	139,200
2503	Supervisor Control Centre	7	7	406	85,100	100,600	105,200	*	103,600	101,000	102,700	100,800	*	102,400	101,800
2504	Supervisor Protection and Control	4	4	496	86,800	105,300	108,500	*	105,300	104,500	108,500	108,000	*	*	107,600
2505	Supervisor Station Maintenance	8	8	496	87,400	102,200	106,800	*	105,400	110,400	105,400	107,600	*	103,900	113,600
2506	Line Supervisor	25	85	366	87,100	99,400	106,800	7%	102,800	102,900	104,100	103,700	4%	106,700	107,300
2507	Manager Meter Department	8	8	506	93,000	109,400	115,700	10%	118,000	118,000	112,600	110,500	6%	118,500	117,400
2508	Supervisor Meter Department	8	8	406	85,500	97,800	102,300	*	99,500	99,200	99,800	98,000	3%	98,800	99,100
3000	Director Supply Chain Management	3	3	*	*	*	*	*	*	140700	*	129300	*	*	140400
3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet	15	15	406	87,100	103,000	108,700	9%	108,300	105,100	103,900	101,800	5%	108,000	105,400
3002	Supervisor Stores/Inventory/Warehouse	6	5	342	73,000	84,000	92,600	*	89,900	86,800	85,400	85,700	*	90,800	87,100

ALL ORGANIZATIONS

		Job Matches			Compensation Design											
Code	Survey Job Title	Sample Statistic		Hay Points	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Bonus %	Total Cash Design		Actual Base Salary		Actual Bonus %	Actual Total Cash	
		# Orgs	# Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
4000	Controller or Director Finance	14	16	588	103,300	113,600	120,800	10%	118,300	125,300	116,400	121,400	9%	120,600	130,000
4001	Manager Accounting	16	16	479	88,700	106,900	120,400	8%	111,100	110,900	100,400	104,100	6%	101,500	109,400
4002	Manager Risk Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
4003	Supervisor Accounting	9	12	342	77,100	90,700	97,000	*	90,700	90,700	91,500	92,200	4%	94,100	95,000
4004	Financial or Business Analyst	14	21	332	74,700	87,200	95,800	6%	87,300	91,900	87,200	88,100	5%	87,200	91,400
4005	Accountant	7	11	342	67,200	84,000	96,600	*	89,900	83,500	73,200	77,300	*	78,900	80,800
5000	Director Customer Service	6	6	578	97,300	112,300	119,400	*	119,800	118,100	117,000	117,400	*	120,100	120,900
5001	Manager Customer Service and/or Billing	20	25	393	85,000	98,000	105,100	7%	101,000	101,500	99,600	99,200	9%	109,600	104,700
5002	Supervisor Customer Service and/or Billing and/or Collections	22	33	353	80,300	92,600	100,700	7%	94,800	92,400	91,900	89,900	4%	93,100	91,800
5500	Director Communications	5	5	677	99,700	124,700	124,700	*	124,700	136,900	124,700	118,500	*	126,700	129,900
5501	Manager Communications	8	8	368	81,100	94,000	94,000	8%	97,200	96,400	91,400	89,300	7%	96,300	93,400
6000	Director Regulatory Affairs	3	3	*	*	*	*	*	*	148,500	*	134,800	*	*	145,400
6001	Manager Regulatory Affairs	14	14	400	86,200	100,200	109,300	7%	100,200	101,200	91,500	94,800	7%	96,700	98,700
6002	Regulatory Accountant	13	13	312	69,500	81,100	90,100	4%	83,500	86,500	77,200	80,000	4%	78,800	83,400
7000	Settlement or Rate Analyst	8	11	282	69,100	82,900	88,200	4%	84,100	87,000	88,200	87,200	2%	94,400	90,800
7001	Director or Officer, Conservation and Demand Management	8	8	666	114,800	126,200	144,900	10%	138,800	148,800	129,300	130,700	5%	134,800	139,600
7002	Manager Conservation & Demand/Marketing	17	16	406	85,600	94,800	107,100	7%	96,800	95,400	97,400	94,300	7%	100,700	95,700
8000	Director Information Systems	14	15	677	110,300	131,500	144,900	15%	157,800	144,400	137,600	133,800	8%	145,800	141,700
8001	Manager Information Systems and/or Security	20	21	479	88,900	106,600	112,300	5%	108,300	109,400	106,600	105,600	5%	107,300	108,400
8002	Systems/Program Administrator or Applications/Systems Support	13	20	337	73,200	87,200	95,300	4%	89,600	91,000	95,200	92,700	4%	99,200	95,200
9000	Human Resources Manager	12	11	479	91,100	103,600	112,700	9%	108,600	114,400	104,000	105,000	6%	107,100	107,600
9001	Human Resources Generalist	12	16	306	75,000	85,200	95,400	3%	89,400	87,100	85,500	84,700	3%	83,900	86,700
9002	Human Resources Coordinator	6	6	218	61,600	71,400	78,700	*	75,000	73,300	73,700	73,200	*	75,000	75,700
9003	Payroll	13	13	245	66,100	79,400	84,400	6%	79,400	81,000	79,400	77,800	5%	80,100	79,900
9004	Manager, Health & Safety	17	18	406	87,100	101,800	108,800	8%	108,000	106,900	103,500	103,700	5%	106,800	108,300

APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range	
Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".
Short Term Incentive	*Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.*
Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.
Current Salary	The amount paid for work performed on a regular, ongoing basis. Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.
Actual STI (Paid)	*Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.* May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90th percentile and 90% would fall below	**11**
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	**7**
P50	50th percentile, also referred to as "median" If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	**4**
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	**7**
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	**11**
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	**3**

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President &CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. OR Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.

Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.
Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/ Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.

Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.
Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudency review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/ Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

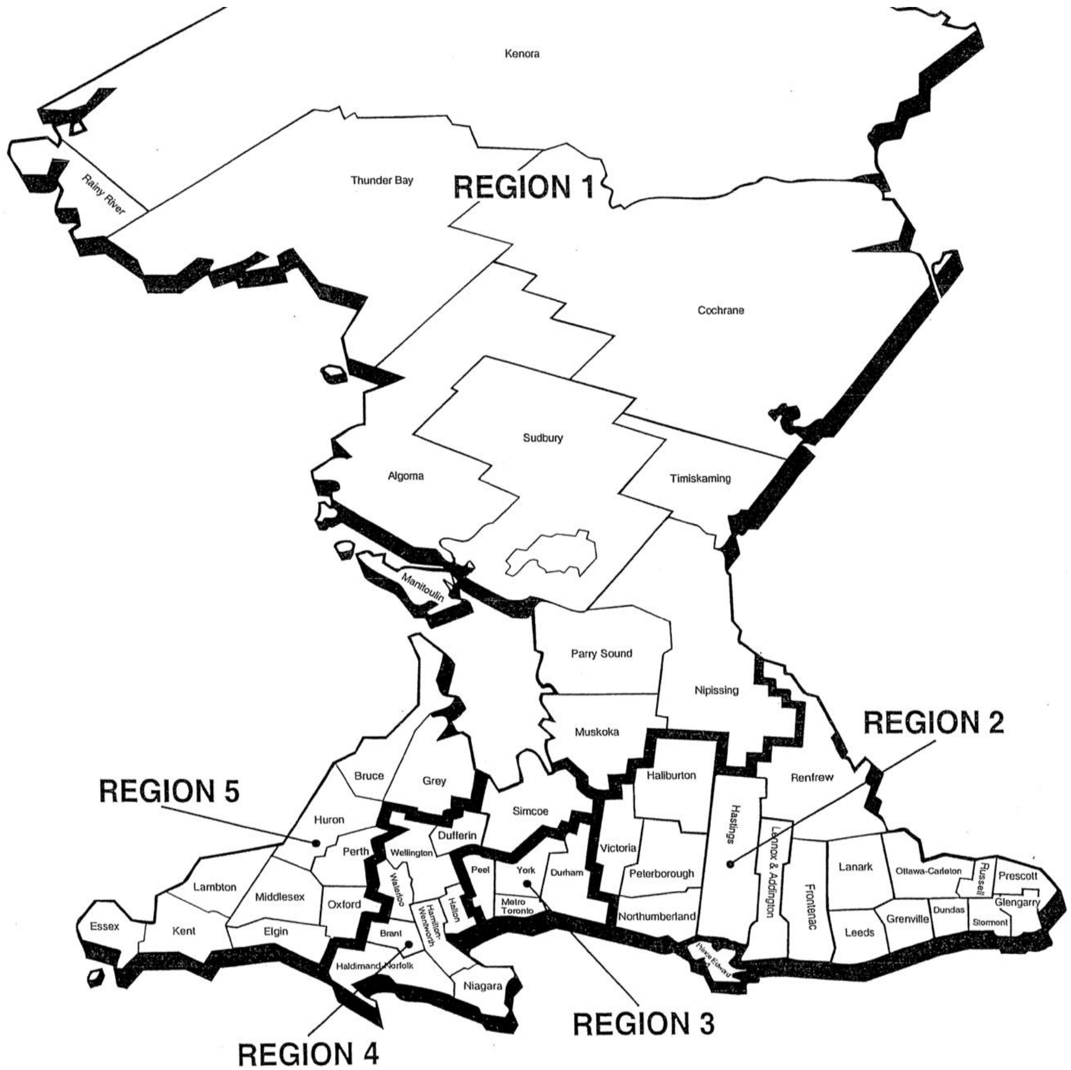
Human Resources

Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions


Kenora
Thunder Bay
REGION 1
Rainy River
Cochrane
Sudbury
Algoma
Timiskaming
Manitoulin
Parry Sound
Nipissing
Muskoka
REGION 2
Renfrew
Haliburton
Bruce
Grey
REGION 5
Huron
Simcoe
Hastings
Dufferin
Perth
Wellington
Victoria
Lennox & Addington
Lanark
Ottawa-Carleton
Russell
Prescott
Lambton
Middlesex
Oxford
Waterloo
Peel
York
Durham
Peterborough
Frontenac
Glengarry
Hamilton-Wentworth
Halton
Metro Toronto
Northumberland
Grenville
Dundas
Stormont
Essex
Kent
Elgin
Brant
Leeds
Haldimand-Norfolk
Prince Edward
Niagara
REGION 3
REGION 4

Festival Hydro INC.

Attachment 15

2024 LV Rates

JANUARY

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	7,426.87	1.63		12,106.54
	RR Group 2	Seaforth TS	7,426.87	-0.01		-53.47
	RR Group 1	Seaforth TS	7,426.87	-0.19		-1,396.25
	RR Group 1	Seaforth TS	7,426.87	-0.13		-995.20
	Common ST Lines	Grand Bend East DS	1,382.37	1.63		2,253.40
	HVDS - High Voltage	Grand Bend East DS	1,382.37	3.42		4,722.73
	RR Group 2	Seaforth TS	1,382.37	0.03		39.40
	RR Group 2	Seaforth TS	1,382.37	-0.04		-49.35
	RR Group 1	Seaforth TS	1,382.37	-0.13		-185.24
	LVDS - Low	Grand Bend East DS:Dashwood F	423.31	2.06		869.90
	LVDS - Low	Seaforth TS:Brussels PME	1,372.37	2.06		2,820.22
					Total	**25,078.36**

FEBRUARY

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			758.79	6	4,552.74
	Common ST Lines	Seaforth TS	7,928.87	1.63		12,924.86
	RR Group 2	Seaforth TS	7,928.87	-0.01		-57.09
	RR Group 2	Seaforth TS	7,928.87	-0.19		-1,490.63
	RR Group 1	Seaforth TS	7,928.87	-0.13		-1,062.47
	Common ST Lines	Grand Bend East DS	1,505.24	1.63		2,453.69
	HVDS - High Voltage	Grand Bend East DS	1,505.24	3.42		5,142.50
	RR Group 2	Seaforth TS	1,505.24	0.03		42.90
	RR Group 2	Seaforth TS	1,505.24	-0.04		-53.74
	RR Group 1	Seaforth TS	1,505.24	-0.13		-201.70
	LVDS - Low	Grand Bend East DS:Dashwood F	474.01	2.06		974.09
	LVDS - Low	Seaforth TS:Brussels PME	1,475.33	2.06		3,031.80
					Total	**26,256.96**

MARCH

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	7,298.99	1.63		11,898.09
	RR Group 2	Seaforth TS	7,298.99	-0.01		-52.55
	RR Group 2	Seaforth TS	7,298.99	-0.19		-1,372.21
	RR Group 1	Seaforth TS	7,298.99	-0.13		-978.06
	Common ST Lines	Grand Bend East DS	1,248.32	1.63		2,034.89
	HVDS - High Voltage	Grand Bend East DS	1,248.32	3.42		4,264.77
	RR Group 2	Seaforth TS	1,248.32	0.03		35.58
	RR Group 2	Seaforth TS	1,248.32	-0.04		-44.57
	RR Group 1	Seaforth TS	1,248.32	-0.13		-167.28
	LVDS - Low	Grand Bend East DS:Dashwood F	394.72	2.06		811.15
	LVDS - Low	Seaforth TS:Brussels PME	1,283.40	2.06		2,637.39
					Total	**24,012.88**

APRIL

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	8,010.26	1.63		13,057.53
	RR Group 2	Seaforth TS	8,010.26	-0.01		-57.67
	RR Group 2	Seaforth TS	8,010.26	-0.19		-1,505.93
	RR Group 1	Seaforth TS	8,010.26	-0.13		-1,073.38
	Common ST Lines	Grand Bend East DS	1,142.50	1.63		1,862.40
	HVDS - High Voltage	Grand Bend East DS	1,142.50	3.42		3,903.25
	RR Group 2	Seaforth TS	1,142.50	0.03		32.56
	RR Group 2	Seaforth TS	1,142.50	-0.04		-40.79
	RR Group 1	Seaforth TS	1,142.50	-0.13		-153.10

	LVDS - Low	Grand Bend East DS:Dashwood F	358.75	2.06		737.23
	LVDS - Low	Seaforth TS:Brussels PME	1,154.81	2.06		2,373.13
					Total	**24,080.92**

MAY

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	6,631.51	1.63		10,810.03
	RR Group 2	Seaforth TS	6,631.51	-0.01		-47.75
	RR Group 2	Seaforth TS	6,631.51	-0.19		-1,246.72
	RR Group 1	Seaforth TS	6,631.51	-0.13		-888.62
	Common ST Lines	Grand Bend East DS	1,429.20	1.63		2,329.73
	HVDS - High Voltage	Grand Bend East DS	1,429.20	3.42		4,882.70
	RR Group 2	Seaforth TS	1,429.20	0.03		40.73
	RR Group 2	Seaforth TS	1,429.20	-0.04		-51.02
	RR Group 1	Seaforth TS	1,429.20	-0.13		-191.51
	LVDS - Low	Grand Bend East DS:Dashwood F	440.17	2.06		904.55
	LVDS - Low	Seaforth TS:Brussels PME	1,087.94	2.06		2,235.72
					Total	**23,723.52**

JUNE

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	6,437.84	1.63		10,494.32
	RR Group 2	Seaforth TS	6,437.84	-0.01		-46.35
	RR Group 2	Seaforth TS	6,437.84	-0.19		-1,210.31
	RR Group 1	Seaforth TS	6,437.84	-0.13		-862.67
	Common ST Lines	Grand Bend East DS	1,479.14	1.63		2,411.14
	HVDS - High Voltage	Grand Bend East DS	1,479.14	3.42		5,053.33
	RR Group 2	Seaforth TS	1,479.14	0.03		42.16
	RR Group 2	Seaforth TS	1,479.14	-0.04		-52.81
	RR Group 1	Seaforth TS	1,479.14	-0.13		-198.20
	LVDS - Low	Grand Bend East DS:Dashwood F	456.43	2.06		937.96
	LVDS - Low	Seaforth TS:Brussels PME	1,224.87	2.06		2,517.11
					Total	**24,031.36**

JULY

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	7,378.98	1.63		12,028.48
	RR Group 2	Seaforth TS	7,378.98	-0.01		-53.13
	RR Group 2	Seaforth TS	7,378.98	-0.19		-1,387.25
	RR Group 1	Seaforth TS	7,378.98	-0.13		-988.78
	Common ST Lines	Grand Bend East DS	1,699.86	1.63		2,770.95
	HVDS - High Voltage	Grand Bend East DS	1,699.86	3.42		5,807.41
	RR Group 2	Seaforth TS	1,699.86	0.03		48.45
	RR Group 2	Seaforth TS	1,699.86	-0.04		-60.69
	RR Group 1	Seaforth TS	1,699.86	-0.13		-227.78
	LVDS - Low	Grand Bend East DS:Dashwood F	520.05	2.06		1,068.70
	LVDS - Low	Seaforth TS:Brussels PME	1,454.38	2.06		2,988.75
					Total	**26,940.78**

AUGUST

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	6,841.45	1.63		11,152.25
	RR Group 2	Seaforth TS	6,841.45	-0.01		-49.26
	RR Group 2	Seaforth TS	6,841.45	-0.19		-1,286.19
	RR Group 1	Seaforth TS	6,841.45	-0.13		-916.75
	Common ST Lines	Grand Bend East DS	1,500.52	1.63		2,446.00

	HVDS - High Voltage	Grand Bend East DS	1,500.52	3.42		5,126.38
	RR Group 2	Seaforth TS	1,500.52	0.03		42.76
	RR Group 2	Seaforth TS	1,500.52	-0.04		-53.57
	RR Group 1	Seaforth TS	1,500.52	-0.13		-201.07
	LVDS - Low	Grand Bend East DS:Dashwood F	454.01	2.06		932.99
	LVDS - Low	Seaforth TS:Brussels PME	1,235.32	2.06		2,538.58
Total						24,677.80

SEPTEMBER

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	7,853.50	1.63		12,801.98
	RR Group 2	Seaforth TS	7,853.50	-0.01		-56.55
	RR Group 2	Seaforth TS	7,853.50	-0.19		-1,476.46
	RR Group 1	Seaforth TS	7,853.50	-0.13		-1,052.37
	Common ST Lines	Grand Bend East DS	1,755.06	1.63		2,860.92
	HVDS - High Voltage	Grand Bend East DS	1,755.06	3.42		5,995.97
	RR Group 2	Seaforth TS	1,755.06	0.03		50.02
	RR Group 2	Seaforth TS	1,755.06	-0.04		-62.66
	RR Group 1	Seaforth TS	1,755.06	-0.13		-235.18
	LVDS - Low	Grand Bend East DS:Dashwood F	534.33	2.06		1,098.05
	LVDS - Low	Seaforth TS:Brussels PME	1,354.15	2.06		2,782.78
					Total	**27,652.20**

OCTOBER

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	7,165.28	1.63		11,680.12
	RR Group 2	Seaforth TS	7,165.28	-0.01		-51.59
	RR Group 2	Seaforth TS	7,165.28	-0.19		-1,347.07
	RR Group 1	Seaforth TS	7,165.28	-0.13		-960.15
	Common ST Lines	Grand Bend East DS	1,199.55	1.63		1,955.39
	HVDS - High Voltage	Grand Bend East DS	1,199.55	3.42		4,098.16
	RR Group 2	Seaforth TS	1,199.55	0.03		34.19
	RR Group 2	Seaforth TS	1,199.55	-0.04		-42.82
	RR Group 1	Seaforth TS	1,199.55	-0.13		-160.74
	LVDS - Low	Grand Bend East DS:Dashwood F	376.69	2.06		774.10
	LVDS - Low	Seaforth TS:Brussels PME	1,238.25	2.06		2,544.60
					Total	**23,469.87**

NOVEMBER

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68
	Common ST Lines	Seaforth TS	8,309.44	1.63		13,545.21
	RR Group 2	Seaforth TS	8,309.44	-0.01		-59.83
	RR Group 2	Seaforth TS	8,309.44	-0.19		-1,562.17
	RR Group 1	Seaforth TS	8,309.44	-0.13		-1,113.46
	Common ST Lines	Grand Bend East DS	1,427.95	1.63		2,327.69
	HVDS - High Voltage	Grand Bend East DS	1,427.95	3.42		4,878.43
	RR Group 2	Seaforth TS	1,427.95	0.03		40.70
	RR Group 2	Seaforth TS	1,427.95	-0.04		-50.98
	RR Group 1	Seaforth TS	1,427.95	-0.13		-191.34
	LVDS - Low	Grand Bend East DS:Dashwood F	458.82	2.06		942.88
	LVDS - Low	Seaforth TS:Brussels PME	1,460.50	2.06		3,001.33
					Total	**26,704.13**

DECEMBER

MONTH	DESCRIPTION	SERVICE POINT	KW	RATE	NUMBER OF ACCOUNTS	TOTAL CHARGE
	Monthly Service Charge			824.28	6	4,945.68

	Common ST Lines	Seaforth TS	7,964.70	1.63		12,983.26
	RR Group 2	Seaforth TS	7,964.70	-0.01		-57.35
	RR Group 2	Seaforth TS	7,964.70	-0.19		-1,497.36
	RR Group 1	Seaforth TS	7,964.70	-0.13		-1,067.27
	Common ST Lines	Grand Bend East DS	1,400.87	1.63		2,283.56
	HVDS - High Voltage	Grand Bend East DS	1,400.87	3.42		4,785.94
	RR Group 2	Seaforth TS	1,400.87	0.03		39.92
	RR Group 2	Seaforth TS	1,400.87	-0.04		-50.01
	RR Group 1	Seaforth TS	1,400.87	-0.13		-187.72
	LVDS - Low	Grand Bend East DS:Dashwood F	470.59	2.06		967.06
	LVDS - Low	Seaforth TS:Brussels PME	1,526.96	2.06		3,137.90
					Total	**26,283.63**

Grand Total	**302,912.39**