ERTH
POWER

October 11, 2024

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

Re: ERTH Power Corporation
EB-2024-0021 –ERTH Power Corporation 2025 Price Cap IR Application

Dear Ms. Marconi,

Please find enclosed the 2024 ERTH Power Inc. ("ERTH") 4th Generation IRM Rate Application, inclusive of a request for Incremental Capital with an ICM. By way of this application, ERTH seeks Ontario Energy Board ("Board") approval for distribution rates for both its Goderich rate zone and its Main rate zone effective May 1, 2025.

In preparing the Application, ERTH utilized the Board's 2025 Rate Generator Model. The basis for the Application and associated models is more fully described in the attached Manager's Summary and Application. The application is supported by written evidence that may be amended from time to time, prior to the Board's decision on this Application. The complete application was submitted today via the Board's web portal in both electronic (i.e., Excel) and PDF form.

If there are any questions, please contact Megan Gooding at 519-485-1820 ext. 212, Megan.Gooding@erthpower.com.

Respectfully,

Digitally signed by Graig Pettit
Date: 2024.10.11 08:51:57 -04'00'

Graig Pettit
Vice President & General Manager

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2. Summary

The Applicant, ERTH Power Corporation, is filing this application for its Incentive Rate Mechanism change to be implemented May 1st, 2025, for both the ERTH Power Main Rate Zone and ERTH Power Goderich Rate Zone. The applicant has followed the methodology set out in "Chapter 3 of the Filing Requirements for Transmission and Distribution Applications: Filing Requirements for Incentive Regulation Mechanisms for Annual Rate Adjustments", as revised up to and including June 18th, 2024 ("Filing Requirements"). All rate adjustments sought are the product of the operation of the 2025 IRM Rate Generator Model, which was issued by the Board on July 26th 2024. The Applicant anticipates the Board will further adjust rates in accordance with the Filing Requirements, especially as it pertains to the Price Cap Adjustment and Retail Transmission Service Rates.

ERTH Power is requesting that its application be heard by way of a written hearing by delegation with OEB staff.

2025 Incremental Capital Module Request

The Applicant has set out at Appendix A an Incremental Capital Module ("ICM") request seeking capital funding for the purchase of property, design, construction, and furnishing of a new administrative and operational facility ("New Facility") with an in-service date in Q4 of 2025. This centralized facility will serve as ERTH Power's new Headquarters, replacing existing administrative and operational facilities which no longer meet the needs of ERTH Power and its customers. Appendix A provides all relevant details supporting ERTH Power's ICM request, and demonstrates that the request meets the OEB's 3-Part ICM test of Materiality, Need and Prudence.

Set out in Appendix B, ERTH Power has provided a Distribution System Plan ("DSP") for integrated capital investment across its Main and Goderich rate zones. The DSP supports ERTH Power's total capital expenditure forecast for 2025 relied upon in the derivation of 2025 maximum eligible incremental capital.

The Applicant has completed OEB ICM Models in support of the New Facility ICM request, provided for the Main and Goderich rate zones as Appendices C and D, respectively.

2024 Tariff Sheet

The Applicant has set out at Appendix F, a copy of the ERTH Power-Main 2024 Tariff Sheet from EB-2023-0019, which was issued in its final form on April 30, 2024. The rates and charges set out in that tariff sheet form the starting point from which the 2025 rates and charges are calculated using the Board's 2025 IRM Models.

The Applicant has set out at Appendix K, a copy of the ERTH Power-Goderich 2024 Tariff Sheet from EB-2023-0019, which was issued in its final form on April 30, 2024. The rates and charges set out in that tariff sheet form the starting point from which the 2025 rates and charges are calculated using the Board's 2025 IRM Models.

2025 IRM Rate Models

The Applicant completed the 2025 IRM Models, as set out at:

- Appendix G ERTH Power-Main Rate Zone (2025 IRM Rate Generator Model),
- Appendix L ERTH Power-Goderich Rate Zone (2025 IRM Rate Generator Model)

Any amendments to the functionality, or operations, of the 2025 IRM Models have been performed by Board Staff and returned to the Applicant in locked format.

ERTH Power worked with the OEB to set the billing determinants between the rate zones as they were not pre-populated and confirm they are accurate as amended.

Price Cap Adjustment – GDP-IPI

The Applicant acknowledges that the Price Cap will be adjusted by the Board. The Board will replace the inflation proxy with the actual GDP-IPI, in accordance with the Filing Requirements. The Applicant reserves the right to subsequently review this adjustment and respond accordingly.

Price Cap Adjustment – Stretch Factor

The applicant has chosen the group 3 stretch factor for both ERTH Power-Main and for ERTH Power-Goderich as it is filing this application as an Incentive Rate Mechanism application and as such is subject to the appropriate stretch factor for that group for each former entity and in accordance with the approved MAAD EB-2018-0082. ERTH has used the Rate Generator Model proxy values of 3.60% as the price escalator (GDP-IPI) a 0.00% Productivity Factor, a Stretch Factor value of 0.30% for ERTH Main and ERTH Goderich as per the OEB letter of December 1st, 2021. This letter detailed that LDC's that are in a current deferral period can move from Annual IR Index to Price Cap IR. ERTH Power understands that OEB staff will adjust for the final GDP-IPI and stretch Factor Group once both factors are available.

Deferral and Variance Account Rate Riders

Deferral and Variance account data has been provided for both of ERTH Power's Rate Zone's as per the Board's process for disposition of Deferral and Variance Accounts. Account 1588 and 1589 balances were last approved for disposition on a final basis in ERTH Power's 2023 IRM application for May 2023 rates with respect to the 2021 year end balances. ERTH Power is not adjusting balances previously approved on a final basis.

ERTH Power has a zero balance in the LRAMVA and is not requesting any disposition.

ERTH Power confirms that residual balances in account 1595 sub accounts being disposed of through this application have only been disposed of once and are being disposed of two years after the expiry of the rate rider.

ERTH Power confirms that it has implemented the OEB's February 21st 2019 guidance for all years that it is seeking disposition for including 2019. Lastly, ERTH Power has populated the GA Analysis Workform for each year not previously disposed of and confirms that there were no adjustments made to account 1589 for years that were previously disposed of.

The balances reported in RRR 2.1.7 for year ending 2023 were reported on a consolidated basis for the ERTH Power Main and ERTH Power Goderich rate zones. ERTH Power has included in its application a reconciliation of it 2.1.7 filing between amounts allocated to the ERTH Main Rate Zone, Goderich Rate Zone and required adjustments to get to the final balances being requested for disposition by zone and is provided in the Table below.

Table –Deferral and Variance Balances by Rate Zone Compared to RRR 2.1.7

		2.1.7 RRR	ERTH Main		ERTH Goderich			
Account Descriptions	Account Number	As of Dec 31, 2023	Closing Principal Balance as of Dec 31, 2023	Closing Interest Amounts as of Dec 31, 2023	Closing Principal Balance as of Dec 31, 2023	Closing Interest Amounts as of Dec 31, 2023	Total	Difference
Group 1 Accounts			BG	BL	BG	BL		
LV Variance Account	1550	(135,863)	(121,163)	(14,699)	0	0	($135,862)	(0)
Smart Metering Entity Charge Variance Account	1551	(121,353)	(97,529)	(4,463)	(18,530)	(831)	($121,352)	(1)
RSVA - Wholesale Market Service Charge[5]	1580	762,290	582,653	51,785	98,185	7,599	$740,222	22,068
Variance WMS – Sub-account CBR Class A[5]	1580	0	0	0	0	0	$0	0
Variance WMS – Sub-account CBR Class B[5]	1580	25,217	23,963	(2,554)	4,354	(641)	$25,123	95
RSVA - Retail Transmission Network Charge	1584	1,310,348	1,084,104	49,991	172,367	8,095	$1,314,556	(4,208)
RSVA - Retail Transmission Connection Charge	1586	634,678	592,026	27,683	13,966	3,156	$636,830	(2,152)
RSVA - Power[4]	1588	(946,911)	(66,214)	(137,005)	9,898	(7,900)	($201,221)	(745,690)
RSVA - Global Adjustment[4]	1589	3,158,390	763,505	164,114	145,085	39,986	$1,112,690	2,045,700
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595-2019	7,059	(45,181)	52,240	$0.00	$0.00	$7,059	(0)
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595-2020	(36,029)	(77,238)	89,910	(79,284)	30,582	($36,029)	(0)
Disposition and Recovery/Refund of Regulatory Balances (2021)3	1595-2021	2,267	11,667	(2,097)	(2,677)	(4,626)	$2,266	2
Disposition and Recovery/Refund of Regulatory Balances (2022)3	1595-2022	0	0	0	0	0	$0	0
Disposition and Recovery/Refund of Regulatory Balances (2023)3	1595-2023	2,642,190	2,103,117	453,233	130,078	(44,235)	$2,642,193	(3)

ERTH Power has balances for Embedded distributors in the sub-account CBR Class B. ERTH Power had no Class A customers that transitioned during the period where Account 1580 CBR Class B sub-account balance accumulated. ERTH Power has no balances for Account 1580 sub-account CBR Class A.

The table above provides the breakdown of the 2.1.7 RRR balances by rate zone.

Minor differences in accounts 1580, 1584 and 1586 are due to interest calculation corrections and are detailed in the following table:

Group 1 Interest Correction		**Main**			**Goderich**			**Total**
Account Description	USoA	RRR	Correction	Difference	RRR	Correction	Difference	**Difference**
RSVA - Wholesale Market Service Charge	1580	$ 45,074	$ 47,760	$ 2,686	$ 9,575	$ 10,038	$ 463	**$ 3,149**
Variance WMS – Sub-account CBR Class B	1580	-$ 2,501	-$ 2,573	-$ 72	-$ 603	-$ 626	-$ 23	**-$ 95**
RSVA - Retail Transmission Network Charge	1584	$ 55,448	$ 59,052	$ 3,604	$ 10,541	$ 11,144	$ 603	**$ 4,208**
RSVA - Retail Transmission Connection Charge	1586	$ 27,207	$ 29,198	$ 1,991	$ 3,076	$ 3,236	$ 161	**$ 2,152**

The difference between the 2.1.7 RRR and the Continuity Schedules for account 1589 is $2,045,698 and is made up of the following amounts:

Account 1589 Difference Explanation	
Total Difference	**$ 2,045,698**
2022 Goderich True-up of GA between RPP and Non-RPP	$ 17,861
2021 Reversal of Goderich True-up of GA between RPP and Non-RPP	$ 47,055
2022 ERTH Main True-up of GA between RPP and Non-RPP	$ 130,954
2021 ERTH Main True-up of GA between RPP and Non-RPP recorded in GL in 2024	$ 2,207,333
2023 Goderich True-up of GA between RPP and Non-RPP	-$ 6,014
2023 Goderich Unbilled Revenue Correction	-$ 40,012
2023 ERTH Main True-up of GA between RPP and Non-RPP	-$ 18,041
2023 ERTH Main Unbilled Revenue Correction	-$ 144,623
Reverse 2022 ERTH Main True-up of GA between RPP and Non-RPP	-$ 130,954
Reverse 2022 Goderich True-up of GA between RPP and Non-RPP	-$ 17,861

The difference between the 2.1.7 RRR and the Continuity Schedules for account 1588 is -$745,689 and is made up of the following amounts:

Account 1588 Difference Explanation	
Total Difference	**-$ 745,689**
2021 Reversal of Goderich True-up of GA between RPP and Non-RPP	-$ 47,055
2021 Reversal ERTH Main True-up	-$ 490,022
Goderich 2022 Principal Adjustments	-$ 85,064
ERTH Main 2022 Principal Adjustments	-$ 1,992,466
Reverse 2021 True-up Accrual	$ 1,106,860
Goderich 2023 Principal Adjustments	$ 35,195
ERTH Main 2023 Principal Adjustments	$ 726,863

GA Workform

The applicant has completed its GA Workform for 2023 for the ERTH Main Rate Zone and for the ERTH Goderich Rate Zone. Within each model ERTH has provided adjustments required and balanced its results to a variance of less than 1% for the entire timeframe across each rate zone. A copy of the GA Workform is included as Appendix H and Appendix M.

ERTH is requesting disposition of its GA balance of $978,099.65 for ERTH Main Rate Zone and $194,663.49 for its Goderich Rate Zone at this time. Please see adjustment required in the ERTH Main rate zone DVAD section.

Tax Change Rate Rider

The Applicant has calculated the 2025 tax change within the IRM Rate Generator Model and the resulting calculation produced an incremental tax savings of ($3,370) for ERTH Power-Main. The low value of this tax savings does not produce any rates within the rate model and therefore no rate rider for the tax change is required. When calculating the tax change within the ERTH Power-Goderich IRM Rate Generator Model the calculation produced a sharing of tax amount of ($3,252). The low value of this tax savings does not produce any rates within the rate model and therefore no rate rider for the tax change is required. WCHE will post the tax savings sharing amount to account 1595 to be disposed of later as part of another proceeding.

Retail Transmission Service Rates

The Applicant presently seeks changes to its Retail Transmission Service Rates for both ERTH Power-Main and ERTH Power-Goderich; the applicant has utilized the RTSR Model and followed the prescribed methodology to determine updated rates that have been proposed as detailed in Section 4.5 and 5.5 respectively and in Appendix G and Appendix L of this application. ERTH Power implemented the formulaic process to calculate its RTSR's any swing in the rates is due to the application of the calculation and beyond the control of the applicant.

ERTH Main and ERTH Goderich rates for the RTSR's for both zones produced an increase in RTSR's and impacts year over year. This is due to the fact that the RTSR rates for the IESO and Hydro One have both increased, IESO Network rates from $5.78 to $6.12 per kW or a 5.9% increase, while connection rates have remained unchanged at $4.16 (Line Connection, and Transformation Connection). Similarly Hydro One rates have remained unchanged at this time at $4.9103 for Network Service Rate and $3.9578 for Connection Charges (both Line Connection and Transformation Connection).

Low Voltage Service Rates

The applicant seeks an update to it approved Low Voltage rates it is charged and passes through to its customers. The applicant has followed the filing guidance provided in the Chapter 3 filing requirements. The applicant notes that it only has Low Voltage charges within its Main service territory and as such the rate does not apply to the Goderich Tariff sheet. The following table details the resulting rates from the IRM model:

Rate Class	Unit	Current LV	Proposed LV	Difference
Residential Service Classification	kWh	$0.0034	$0.0030	-$0.0004
General Service Less Than 50 kW Service Classification	kWh	$0.0031	$0.0028	-$0.0003
General Service 50 To 999 kW Service Classification	kW	$1.1189	$1.0129	-$0.1060
General Service 1,000 To 4,999 kW Service Classification	kW	$1.1986	$1.0851	-$0.1135
Large Use Service Classification	kW	$1.3596	$1.2308	-$0.1288
Unmetered Scattered Load Service Classification	kWh	$0.0031	$0.0028	-$0.0003
Sentinel Lighting Service Classification	kW	$0.0031	$0.0028	-$0.0003
Street Lighting Service Classification	kW	$1.4231	$1.2878	-$0.1353
Embedded Distributor Service Classification	kW	$1.5809	$1.4310	-$0.1499

Other Rates and Charges

The Applicant also seeks continuation of the other rates and charges approved in EB-2019-0033 specifically the Allowances, Specific Service Charges, Retail Service Charges, and Loss Factors.

2025 Tariff Sheet

The Applicant has set out at Appendix I and Appendix N a copy of the 2025 Tariff Sheet from the 2025 IRM Rate Generator Model for each of ERTH Power's Rate Zones in the application. It is important to note that in respect of the USL, Sentinel Lighting and Street Lighting classes, the 2025 IRM Rate Generator Model's Tariff Sheet there are "per connection" rates and charges for certain line items. Rates for these classes have been calculated on a per connection basis, as set out in the 2025 IRM Rate Generator Model, for:

- Service Charge

2025 Bill Impacts

The Applicant has set out at Appendix L and Appendix O a copy of the 2025 Bill Impacts from the 2025 IRM Rate Generator Model for the respective Rate Zones. All rate classes will be affected by this Application. Based on the current data, the rate changes calculated include the following increases.

The Applicant has also included (as required by updated chapter 3 filing requirements) bill impacts for the lowest 10th percentile of residential consumption. These impacts are included to determine if the movement towards fixed price distribution in the residential class has impacts for the lowest volume consumers that need to be mitigated. ERTH

Power calculated the lowest 10th percentile by including all of its customers' average monthly consumption, removing all customers with zero consumption or a partial month such as first or final bills. Once these customers were removed, the lowest 10th percentile was calculated and an average of their monthly usage (233 kWh's Main Rate Zone & 136 kWh's Goderich Rate Zone) was determined and utilized to calculate bill impacts.

ERTH Power Main Rate Zone Impact Summary exclusive of ICM Request:

		Distribution		Total Bill	
Rate Class	**kWh**	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**
Residential	750	$ 1.20	3.30%	$ 0.85	0.62%
Residential	1000	$ 1.20	3.30%	$ 0.75	0.44%
Residential	233	$ 1.20	3.30%	$ 1.04	1.56%
GS<50 kW	2000	$ 1.86	3.17%	$ 1.56	0.48%

ERTH Power Goderich Rate Zone Impact Summary exclusive of ICM Request:

		Distribution		Total Bill	
Rate Class	**kWh**	**$ Impact**	**% Impact**	**$ Impact**	**% Impact**
Residential	750	$ 1.27	3.30%	-$ 2.67	-1.93%
Residential	1000	$ 1.27	3.30%	-$ 3.95	-2.29%
Residential	136	$ 1.27	3.30%	$ 1.82	2.78%
GS<50 kW	2000	$ 2.03	3.22%	-$ 8.39	-2.56%

3. Overview-The Story of ERTH

Formation of the Erie Thames Power Group of Companies now “ERTH Corporation”

In late 1999 and early 2000, the Ontario government enacted the *Energy Competition Act, 1998* (Bill 35), deregulating Ontario’s electricity industry. In response, on September 1, 2000, Erie Thames Power Corporation (“Erie Thames”) and its subsidiaries, Erie Thames Powerlines Corporation (“ET Powerlines”) and Erie Thames Services Corporation (“ET Services”) were created pursuant to section 142 of the *Electricity Act, 1998* (the “*EA*”) and sections 71 and 73 of the Ontario *Energy Board Act, 1998* (the “*OEB Act*”). These provisions allowed municipalities to enact bylaws to facilitate the amalgamation of their public utilities into Ontario *Business Corporations Act* corporations.

Erie Thames was formed through the amalgamation of seven separate public utilities owned by the municipal corporations of the Town of Ingersoll, Township of East Zorra-Tavistock, Township of Zorra, Municipality of Central Elgin, Township of South-West Oxford, Town of Aylmer and Township of Norwich (collectively, the “Municipal Shareholders”). By virtue of the transfer by-laws passed by the councils of these municipalities, the former local public utilities were rendered inactive and replaced by Erie Thames, and each of the municipalities became shareholders in Erie Thames, with each holding an equal number of voting shares.

Erie Thames was created as a holding company with its principal business to provide oversight of and shared corporate services (e.g. legal, financial/accounting, regulatory) to its wholly owned subsidiary companies, ET Powerlines and ET Services. Through ET Services, Erie Thames would provide similar services to its municipal customer base that were provided by the former public utilities, and also seek to expand its customer base through organic sales growth and future acquisitions and amalgamations in respect of its non-regulated businesses. These objectives were reflected in the founding principles and the vision, mission and goals of Erie Thames in 2000:

Founding Principles

- Local presence/control/involvement
- Build on commitment to customer care
- Provide safe, reliable supply of electricity
- Shareholder returns
- Local employment

- Mitigate consumer rate impacts

Erie Thames' wholly owned subsidiaries were established to provide regulated electricity and non-regulated services. ET Powerlines took over the ownership and operation of the electricity infrastructure from the Municipal Shareholders. ET Services, incorporated as an non-regulated operating company, provided services to electric utilities (including ETPL), municipalities and developers, including, water, sewer and electricity billings for utility companies, electricity grid expansion and maintenance services, traffic signal installation services, and meter reading, verification and maintenance.

Responding to its original vision, mission and goals, which charted a path to growth, Erie Thames experienced significant growth between the period of 2000 and 2018 through an organic increase in customers and the acquisition of new businesses. It also underwent a number of organizational changes, which included the creation of new business lines, amalgamations, reorganizations and a major rebranding of ETP and its subsidiaries. Highlights of these changes are detailed below.

Regulated Electricity Distribution Growth

After 2000, Erie Thames sought to expand the regulated electricity distribution side of its business to include a larger territory in southwestern Ontario. It accomplished this by leveraging our affiliate business service offerings; building a strategic relationship that lead to the following transactions:

- ***December 2010: Acquisition of all of the shares of West Perth Power Inc. ("WPPI") and Clinton Power Corporation ("Clinton Power")***, thus expanding its regulated electricity distribution customer base to approximately 19,500 customers. With this purchase, the Municipalities of Central Huron and West Perth became shareholders in ERTH under the "one share, one vote" governance model.

- ***2018: Acquisition of all of the shares of West Coast Huron Energy Inc. – Goderich Hydro ("WCHEI")***, On December 20th, 2018 the Ontario Energy Board approved the merger between WCHEI and ERTH Power Corporation. This approval expanded the regulated electricity distribution customer base to approximately 24,000 customers in 15 communities across 4 counties thus creating a regional footprint to continue grow the regulated business. The closing documents were executed on January 8th, 2019 officially amalgamating the two Utilities. With this purchase, the Town of Goderich became a shareholder in ERTH under the "one share, one vote" governance model.

Affiliate Growth and New Companies

After its incorporation in 2000, Erie Thames established itself as a successful, non-regulated business offering services to utilities, municipalities and large industrial companies. Erie Thames then sought to expand ET Services' service offerings to new, but related, areas through the acquisition of a number of businesses beginning in 2004. As a result of ET Services' success and new acquisitions, the number of employees grew from 35 in 2000 to over 120 by 2018.

Corporate Reorganization and Rebranding:

Erie Thames group of companies rebranded in 2008 and in 2009 in response to OEB restrictions imposed on LDCs' relationships with their non-regulated affiliates. As a result, Erie Thames Power (the Holdco) was rebranded as ERTH Corporation and ET Services was split into CRU Solutions, Ecaliber and ET Powerlines.

Evolution of ERTH's Strategic Direction

ERTH revisited its strategic direction, goals and objectives a number of times since 2000 as the corporation continued with its growth. With each change, ERTH sought to encapsulate the best strategic vision for the corporation that would help to ensure its continued success and profitability and maximize shareholder returns.

In 2018, ERTH shareholders approved the strategic vision to rebrand the regulated business. Erie Thames Powerlines rebranded to ERTH Power thus removing the geographic limitations of the former name. ERTH Power Corporation now leverages the Holdco and affiliate brand to further mark its place within the industry.

Finally, in 2019 ERTH Power and West Coast Huron Energy (Goderich Hydro) after a longstanding working relationship completed a merger of the two organizations.

4. ERTH Power Main Rate Zone

4.1. Preparation of Rates

ERTH Power Corporation's application will be filed through the Board's web portal at www.errr.oeb.gov.on.ca, consisting of one (1) electronic copy of the application in searchable/unrestricted PDF format and one (1) electronic copy in Microsoft Excel format of the following complete IRM models:

This Application is supported by written evidence for ERTH Power-Main Rate Zone and using the following board models and work forms:

- 2025 IRM Rate Generator Model (Version 1.0) issued on July 26th, 2024.
- GA Analysis Work Form updated on April 16th, 2024.
- IRM Checklist issued on July 18th, 2024.
- Capital Module Applicable to ACM & ICM

4.2. Current Tariff Schedule

A copy of ERTH Power-Main Rate Zone’s Approved Tariff Sheet (EB-2023-0019) has been included as Appendix F in this application.

4.3. DVAD Disposition

Deferral and Variance Accounts Balance Disposition

ERTH Power Main rate zone is complex with respect to settlement having sections of its territory Transmission connected, others embedded within Hydro One, Hydro One embedded within ERTH and a significant amount of embedded generation. ERTH Main zone also has generation connected to one of its communities that is large enough (20 MW) to inject a significant amount of its load back into the IESO controlled grid. ERTH Main manages 14 Class A customers and 14 community connections.

Chapter 3 of the Board's Filing Requirements and the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report (the "EDDVAR Report") provide that under the Price Cap IR, the distributor's Group 1 audited accounts balances will be reviewed and disposed of if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. Distributors must file in their application Group 1 balances as at December 31, 2022 to determine if the threshold has been exceeded. ERTH has completed the Board Staff's 2025 IRM Rate Generator Tab 3: and has projected interest. Actual interest has been calculated based on the Board's prescribed rates for 2024 and includes the disposition approved for 2022 as the 2025 approved disposition does not commence until May 1, 2025. The table below displays the deferral and variance account balance requested for disposition:

Table: Deferral and Variance Account Disposition Balances

ERTH Power Main Rate Zone		
LV Variance Account	1550	-$124,067.40
Smart Metering Entity Charge Variance Account	1551	-$42,984.58
RSVA - Wholesale Market Service Charge[5]	1580	-$538,897.07
Variance WMS – Sub-account CBR Class A[5]	1580	$0.00
Variance WMS – Sub-account CBR Class B[5]	1580	$57,552.06
RSVA - Retail Transmission Network Charge	1584	$321,547.15
RSVA - Retail Transmission Connection Charge	1586	$285,405.02
RSVA - Power[4]	1588	-$207,596.50
RSVA - Global Adjustment[4]	1589	$978,099.65
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	$7,565.94
LRAMVA	1568	$0.00
Grand Total		**$736,624.28**

ERTH Power is proposing to dispose of these balances over a 12 month period. The following table details the proposed rate riders by class to recover the deferral and variance account balances.

ERTH Power Main Rate Zone		DVAD		GA		CBR Class B
Rate Class	**Unit**	**Rate Rider**	**Unit**	**Rate Rider**	**Unit**	**Rate Rider**
Residential Service Classification	kWh	$ 0.0005	kWh	$ 0.0104	kWh	$0.0002
General Service Less Than 50 kW Service Classification	kWh	$ 0.0007	kWh	$ 0.0104	kWh	$0.0002
General Service 50 To 999 kW Service Classification	kW	$ 0.2575	kWh	$ 0.0104	kW	$0.0635
General Service 1,000 To 4,999 kW Service Classification	kW	$ 0.3554	kWh	$ 0.0104	kW	$0.0668
Large Use Service Classification	kW	$ 0.4383	kWh	$ -	kW	$0.0000
Unmetered Scattered Load Service Classification	kWh	$ 0.0008	kWh	$ 0.0104	kWh	$0.0002
Sentinel Lighting Service Classification	kW	$0.0008	kWh	$ 0.0104	kWh	$0.0002
Street Lighting Service Classification	kW	$ 0.2806	kWh	$ 0.0104	kW	$0.0721
Embedded Distributor Service Classification	kW	$ 0.3530	kWh	$ 0.0104	kW	$0.0907

Global Adjustment and the IESO Settlement Process

ERTH POWER uses the Global Adjustment (GA) first estimate provided by the IESO to invoice its customers. This treatment is applicable to all customer classes on Non-RPP with the exception of the Class A customers. The Class A customers are billed the actual GA that is invoiced to ERTH POWER from the IESO. The Class A customers are thus excluded in any of the allocations for the disposal of Global Adjustment variance accounts.

ERTH POWER settles monthly with the IESO for the difference between spot and RPP pricing for RPP customers that are billed Time of Use (TOU) or Tiered pricing. The settlement is filed with the IESO within four business days of month end and uses billed data to calculate a prorated amount of usage for settlement. A true-up calculation is completed every month for the previous months and is then added/subtracted from the next month's IESO submission. At the end of the fiscal year ERTH Power accrues for any unbilled usage along with the settlement amount with the IESO for this unbilled usage.

ERTH POWER allocates the Class B Global Adjustment between RPP and Non-RPP customers (excluding the 1 Class A Customer) based on actual billed consumption.

ERTH POWER reports to the IESO within four business days of month end the total kWHs purchased from embedded generation within its service territory to calculate total kWhs purchased for the month.

ERTH POWER confirms it uses accrual accounting in its Global Adjustment.

4.4. Shared Tax Savings

ERTH Power Corporation has completed the 2025 IRM Rate Generator tabs related to tax changes for IRM applications to calculate the savings due to rate payers as a result of corporate tax saving implemented since the 2018 Cost of Service Decision (EB-2017-0038). The Board determined under the 4th Generation IRM that a 50/50 sharing of the impact of currently known legislated tax changes as applied to the tax level reflected in the Board-approved base rates for a distributor is appropriate. The calculated annual tax changes over the plan term will be allocated to customer rate classes based on the most recent Board-approved base year distribution revenue.

ERTH completed Tab 8: Shared Tax – Rate Rider to calculate rate riders for tax change which indicates a shared tax savings is $3,370. This tax savings does not produce rate riders that are material and will be added to account 1595 to be disposed of at a later date.

4.5. Retail Transmission Rates

ERTH Power is charged Ontario Uniform Transmission Rates ("UTR") by Hydro One Networks and the Independent Electricity System Operator, and in turn has Board approved retail transmission service rates to charge end user customers in order to recover the expenses. Based on Hydro One Networks most recent Decision and Rate Order of the Board in the EB-2024-0183 proceeding, the UTRS's for IESO and HONI effective January 1, 2025 are:

- $6.12/kW/mth for Network Service Rate
- $0.95/kW/mth for Line Connection Service Rate
- $3.21/kW/mth for Transformation Connection Service Rate

- $4.5778/kW/mth for Network Service Rate
- $0.6056/kW/mth for Line Connection Service Rate
- $3.0673/kW/mth for Transformation Connection Service Rate

Variance accounts are used to track the timing and rate differences in UTR's paid and RTSR's billed; they are recorded in USoA Accounts 1585 and 1586. On June 28, 2012, the Ontario Energy Board (the "Board") issued revision 4.0 of the Guideline G-2008-0001 Electricity Distribution Retail Transmission Service Rates (the "Guideline"). This Guideline outlines the information that the Board requires electricity distributors to file when proposing adjustments to their retail transmission service rates. The guideline was used to adjust ERTH's RTSRs for 2025.

The billing determinants used on Tab 10: RTSR Current Rates of the 2025 IRM Rate Generator Model were derived from the RRR 2.1.5 Performance Based Regulation filing for the annual consumption in compliance with the instruction to use the most recent reported RRR billing determinants. The billing determinants are non-loss adjusted.

The OEB has provided a model for electrical distributors to calculate and predict the distributor's specific RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. ERTH has completed the model and included the 2022 historical RTSR Network and RTSR Connection data on Tab 12: TRSR – Historical Wholesale of the 2025 IRM Rate Generator Model. ERTH acknowledges that parties to the proceeding will have an opportunity to review the resulting rates as part of the rate process. A summary of the current and proposed RTSRs from the 2025 IRM Rate Generator are provided in the table below:

Table: Summary of Retail Transmission Rates and Charges:

Rate Class	Unit	Current RTSR		Proposed RTSR		Difference	
		Network	Connection	Network	Connection	Network	Connection
Residential Service Classification	kWh	$0.0092	$0.0080	$0.0093	$0.0080	$0.0001	-$0.0000
General Service Less Than 50 kW Service Classification	kWh	$0.0087	$0.0076	$0.0088	$0.0076	$0.0001	-$0.0000
General Service 50 To 999 kW Service Classification	kW	$3.9145	$2.7024	$3.9760	$2.6959	$0.0615	-$0.0065
General Service 1,000 To 4,999 kW Service Classification	kW	$4.2496	$2.8951	$4.3164	$2.8881	$0.0668	-$0.0070
Large Use Service Classification	kW	$4.7111	$3.2839	$4.7851	$3.2760	$0.0740	-$0.0079
Unmetered Scattered Load Service Classification	kWh	$0.0087	$0.0076	$0.0088	$0.0076	$0.0001	-$0.0000
Sentinel Lighting Service Classification	kW	$0.0087	$0.0076	$0.0088	$0.0076	$0.0001	-$0.0000
Street Lighting Service Classification	kW	$3.0215	$3.4360	$3.0690	$3.4277	$0.0475	-$0.0083
Embedded Distributor Service Classification	kW	$5.6852	$3.8180	$5.7745	$3.8088	$0.0893	-$0.0092

4.6. Price Cap Adjustment

Based on the most recent PEG Report, issued on August 6th, 2024, the OEB has updated the stretch factor assignments for 2025. ERTH Power-Main Rate Zone remained in the Stretch Factor Group III with a stretch factor assignment of 0.30%. For the period from 2021 to 2023, ERTH's average actual benchmarked costs were 5.9% lower than the predicted costs for the period based on the PEG econometric model.

Furthermore, as part of the Renewed Regulatory Framework for Electricity Distributors ("RRFE") the Board initiated a review of utility performance per the "Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379)" proceeding. As part of this proceeding the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board". The original PEG Report was issued on May 3, 2013, and established the parameters for use to determine the Price Cap Index for the 4th Generation IRM including: a productivity factor of 0.00% was established, the approach to determine the Industry.

Consistent with the policy determinations set out in the Report of the Board on Rate Setting Parameters and Benchmarking under the RRFE for Ontario's Electricity Distributors (EB-2010-0379) (Issued November 21, 2013 and updated December 4, 2013), the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2025, to be 3.6%. The derivation of this is shown in the following table.

Year	Annual GDP-IPI % Change (Table 1)	Weight	AWE % Change (Table 2)	Weight	Annual IPI	Annual % Change
2022					125.0	
2023	3.7%	70%	3.2%	30%	129.6	**3.6%**

The price cap adjustment as determined in the 2025 IRM Rate Generator Model submitted with this application is based on a Price Cap Index from The Board's letter on June 29th, 2024 of 4.50%, which has been used to determine the 2025 Distribution Rates, as follows:

1. Price Escalator of 3.60%

2. Minus a Productivity Factor of 0.0%

3. Minus a Stretch Factor of 0.30% based on ERTH 's current OEB approved Stretch Factor Group III, and

4. The resulting Price Cap Index of 3.30%

ERTH Power-Main Rate Zone proposes 2025 distribution rate adjustments to both the Monthly Fixed Service Charge and Distribution Volumetric Rate for all rate classes reflecting the calculated values that are generated by the 2025 Rate Generator Model.

ERTH Power-Main acknowledges that the Price Cap Index Adjustment is no longer applied to Low Voltage Service rates as per Section 3.2.1.1 of the Filing Requirements. Accordingly, ERTH Power-Main proposes to adjust its Low Voltage Service rates approved in the ERTH Power-Main 2018 COS Application utilizing the IRM model and its historical data. The following table details the results of the LV rate calculations and are requested to be updated in ERTH Main's tariff sheet:

Rate Class	Unit	Current LV	Proposed LV	Difference
Residential Service Classification	kWh	$0.0034	$0.0030	-$0.0004
General Service Less Than 50 kW Service Classification	kWh	$0.0031	$0.0028	-$0.0003
General Service 50 To 999 kW Service Classification	kW	$1.1189	$1.0129	-$0.1060
General Service 1,000 To 4,999 kW Service Classification	kW	$1.1986	$1.0851	-$0.1135
Large Use Service Classification	kW	$1.3596	$1.2308	-$0.1288
Unmetered Scattered Load Service Classification	kWh	$0.0031	$0.0028	-$0.0003
Sentinel Lighting Service Classification	kW	$0.0031	$0.0028	-$0.0003
Street Lighting Service Classification	kW	$1.4231	$1.2878	-$0.1353
Embedded Distributor Service Classification	kW	$1.5809	$1.4310	-$0.1499

As part of ERTH Power's request, the actual Low Voltage costs for the last five years are presented below along with the year-over-year variances. There was a substantive increase from 2019 to 2020 as this was the first full year the Volumetric Rate Rider applied. The costs decreased in following years with the decrease in the Volumetric Rate Rider Applied.

2019	2020	2021	2022	2023
1,578,812	2,034,813	2,013,375	1,470,245	1,300,632
	29%	-1%	-27%	-12%

4.7. Residential Rate Design Transition

On April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410), which stated that electricity distributors would transition to a fully fixed monthly distribution service charge for residential customers. This process will be implemented over a period of four years, beginning in 2016. ERTH Power-Main Rate Zone has transitioned to fully fixed rates and no further adjustments or mitigation for low volume consumers is required.

4.8. Additional Rates

ERTH Power-Main Rate Zone is not proposing any additional rates outside of those detailed in other sections of the application.

4.9. Regulatory Charges

ERTH Power-Main Rate Zone proposed to continue to utilize the previously approved WMS, CBDR and RRRP rates unless otherwise directed by the door. These rates are \$0.0041/kWh, \$0.0004/kWh and \$0.0007/kWh respectively.

4.10. Proposed Rates

A copy of ERTH Power-Main Rate Zone's Proposed Tariff Sheet has been included in this application as Appendix I.

4.11. Bill Impacts

As shown in the table, the impact of the Rate Design on the Residential class is marginal.
ERTH –Main rate zone has included bill impacts for the following classes:

- Residential – RPP and non-RPP
- GS<50 kW – RPP and non-RPP
- GS 50-999 kW
- GS 1000-4999 kW
- Large Use
- Unmetered Scattered Load
- Sentinel Lighting
- Street lighting
- Embedded Distributor

Detailed bill impacts for each rate class are provided in Appendix J.

The following tables demonstrate the impact of ERTH Power's IRM application exclusive of the impacts of the New Facility ICM Request:

Table: Summary of Bill Impacts exclusive of ICM Request

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	2,000		CONSUMPTION	
GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	64,700	125	DEMAND	
GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	821,250	1,700	DEMAND	
LARGE USE SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	3,942,000	15,000	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	100		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	657		DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	657		DEMAND	1
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0467	1.0467	136		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0467	1.0467	750		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	136		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	1,000		CONSUMPTION	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	27,488		DEMAND	

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.20	3.3%	$ 0.83	1.9%	$ 0.90	1.6%	$ 0.85	0.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.86	3.2%	$ 1.46	1.8%	$ 1.67	1.5%	$ 1.56	0.5%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 16.28	3.3%	$ (494.64)	-38.3%	$ (489.14)	-25.0%	$ (552.73)	-5.1%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 172.11	3.3%	$ (6,438.77)	-40.2%	$ (6,364.02)	-25.5%	$ (7,191.34)	-5.3%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,288.35	3.3%	$ (15,369.79)	-16.5%	$ (14,553.46)	-7.6%	$ (16,445.40)	-2.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 0.51	3.3%	$ (0.50)	-2.8%	$ (0.49)	-2.3%	$ (0.55)	-1.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 0.81	3.3%	$ 0.73	2.9%	$ 0.73	2.7%	$ 0.83	2.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 0.97	3.3%	$ (4.05)	-10.1%	$ (4.01)	-8.6%	$ (4.53)	-3.3%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 139.01	3.3%	$ (371.99)	-5.5%	$ (319.12)	-2.4%	$ (360.61)	-2.0%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.20	3.3%	$ 1.08	2.8%	$ 1.11	2.6%	$ 1.04	1.6%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 1.20	3.3%	$ (0.55)	-1.3%	$ (0.52)	-1.2%	$ (0.59)	-0.7%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 1.20	3.3%	$ (4.80)	-9.3%	$ (4.72)	-7.2%	$ (5.33)	-3.0%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.20	3.3%	$ 0.70	1.5%	$ 0.80	1.2%	$ 0.75	0.4%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.11	3.3%	$ 1.01	2.5%	$ 1.06	2.2%	$ 0.99	1.0%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.36	3.2%	$ 1.16	2.2%	$ 1.26	1.8%	$ 1.18	0.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 3.36	3.1%	$ (32.64)	-16.5%	$ (32.12)	-11.4%	$ (36.30)	-3.8%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 62.36	3.3%	$ (652.64)	-17.3%	$ (625.14)	-8.8%	$ (706.41)	-4.2%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 246.48	3.3%	$ (7,226.52)	-32.1%	$ (7,077.02)	-17.5%	$ (7,997.03)	-5.2%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 305.98	3.3%	$ (7,856.72)	-28.4%	$ (7,647.42)	-14.5%	$ (8,641.58)	-5.1%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,168.86	3.3%	$ 115.33	0.3%	$ 170.21	0.3%	$ 192.34	0.3%

Table: Summary of Bill Impacts inclusive of ICM Request

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0325	1.0325	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0325	1.0325	2,000		CONSUMPTION	
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	65,700	100	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	821,250	1,250	DEMAND	
LARGE USE SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	2,942,000	12,350	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0325	1.0325	150		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0325	1.0325	80		CONSUMPTION	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	657	1	DEMAND	1
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	23,500	660	DEMAND	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0325	1.0325	233		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0325	1.0325	233		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0325	1.0325	800		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0325	1.0325	1,000		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0325	1.0325	500		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0325	1.0325	1,000		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0325	1.0325	5,000		CONSUMPTION	
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	65,700	500	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	821,250	2,500	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	821,250	3,500	DEMAND	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0325	1.0325	64,944	1,400	DEMAND	

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.64	21.0%	$ 7.27	16.3%	$ 7.34	12.7%	$ 6.88	5.0%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 12.25	20.9%	$ 11.85	14.9%	$ 12.06	10.7%	$ 11.30	3.5%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 103.63	21.0%	$ (407.29)	-31.5%	$ (401.79)	-20.6%	$ (454.02)	-4.2%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,096.12	21.0%	$ (5,514.76)	-34.4%	$ (5,440.01)	-21.8%	$ (6,147.21)	-4.5%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 8,201.37	21.0%	$ (8,456.77)	-9.1%	$ (7,640.44)	-4.0%	$ (8,633.70)	-1.4%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 3.30	21.0%	$ 2.28	12.4%	$ 2.29	11.0%	$ 2.59	6.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 5.15	21.0%	$ 5.07	19.9%	$ 5.08	18.9%	$ 5.74	14.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 6.23	21.0%	$ 1.20	3.0%	$ 1.24	2.7%	$ 1.40	1.0%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 884.92	21.0%	$ 373.92	5.5%	$ 426.79	3.3%	$ 482.27	2.7%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.64	21.0%	$ 7.52	19.2%	$ 7.55	17.4%	$ 7.07	10.6%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 7.64	21.0%	$ 5.89	14.4%	$ 5.92	13.1%	$ 6.69	8.3%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 7.64	21.0%	$ 1.64	3.2%	$ 1.72	2.6%	$ 1.95	1.1%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.64	21.0%	$ 7.14	15.2%	$ 7.24	11.2%	$ 6.79	4.0%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 7.15	20.9%	$ 7.05	17.8%	$ 7.10	14.8%	$ 6.65	6.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 8.85	20.9%	$ 8.65	16.4%	$ 8.75	12.6%	$ 8.20	4.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 22.45	20.8%	$ (13.55)	-6.8%	$ (13.03)	-4.6%	$ (14.73)	-1.5%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 396.91	21.0%	$ (318.09)	-8.4%	$ (290.59)	-4.1%	$ (328.37)	-2.0%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,569.99	21.0%	$ (5,903.01)	-26.2%	$ (5,753.51)	-14.3%	$ (6,501.47)	-4.2%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,949.09	21.0%	$ (6,213.61)	-22.4%	$ (6,004.31)	-11.4%	$ (6,784.87)	-4.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 7,441.98	21.0%	$ 6,388.45	15.9%	$ 6,443.33	13.1%	$ 7,280.97	11.3%

ERTH Power proposes no rate mitigation. When including the impacts of the ICM Request, a short-list of rate classes experience bill impacts which exceed 10% on a Total Bill basis, however bill impacts rise only marginally above the 10% threshold. With respect to the two Street Lighting bill impact scenarios modelled, ERTH Power submits these customers (which are also shareholders of the ERTH CORP) have the financial wherewithal to absorb the presented bill impacts. With respect to low volume Residential RPP customers, Total Bill impacts exceed 10% by only 0.6%, and are elevated relative to typical Residential RPP customers by virtue of the relatively lower Total Bills of low volume consumers. ERTH Power submits the Total Bill Impact in dollars is reasonable and does not require rate mitigation.

5. ERTH Power-Goderich Rate Zone

5.1. Preparation of Rates

ERTH Power Corporation's application will be filed through the Board's web portal at www.errr.oeb.gov.on.ca, consisting of one (1) electronic copy of the application in searchable/unrestricted PDF format and one (1) electronic copy in Microsoft Excel format of the following complete IRM models:

This Application is supported by written evidence for ERTH Power-Main Rate Zone and using the following board models and work forms:

- 2025 IRM Rate Generator Model (Version 1.0) issued on July 26th, 2024.
- GA Analysis Work Form updated on April 16th, 2024.
- IRM Checklist issued on July 18th, 2024.
- Capital Module Applicable to ACM & ICM

5.2. Current Tariff Schedule

A copy of ERTH Power-Goderich Rate Zone’s Approved Tariff Sheet (EB-2023-0019) has been included as Appendix K in this application.

5.3. DVAD Disposition

Deferral and Variance Accounts Balance Disposition

ERTH Power Corporation has completed an extensive review of its historical balances of Accounts 1588 Power, and 1589 RSVA Global Adjustment. After its review it has determined that there were inconsistencies with respect to its filing of 1598 submissions with the IESO. During this review ERTH Power was also able to validate and the global adjustment splits between RPP and Non RPP customers. After the completion of this process and adjustments filed with the IESO. The balances requested for disposition here represent amounts after these adjustments.

Chapter 3 of the Board's Filing Requirements and the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report (the "EDDVAR Report") provide that under the Price Cap IR, the distributor's Group 1 audited accounts balances will be reviewed and disposed of if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. Distributors must file in their application Group 1 balances as at December 31, 2019 to determine if the threshold has been exceeded. ERTH has completed the Board Staff's 2025 IRM Rate Generator Tab 3: and has projected interest. Actual interest has been calculated based on the Board's prescribed rates for 2024 and includes the disposition approved for 2024 as the 2024 approved disposition does not commence until January 1, 2025. The table below displays the deferral and variance account disposition balances for ERTH Goderich Rate Zone:

Table: Deferral and Variance Account Disposition Balances

ERTH Power Goderich Rate Zone		
LV Variance Account	1550	$0.00
Smart Metering Entity Charge Variance Account	1551	-$8,279.75
RSVA - Wholesale Market Service Charge[5]	1580	-$105,789.55
Variance WMS – Sub-account CBR Class A[5]	1580	$0.00
Variance WMS – Sub-account CBR Class B[5]	1580	$13,226.80
RSVA - Retail Transmission Network Charge	1584	$5,606.42
RSVA - Retail Transmission Connection Charge	1586	-$62,414.63
RSVA - Power[4]	1588	$2,652.17
RSVA - Global Adjustment[4]	1589	$194,663.49
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	-$53,943.53
LRAMVA	1568	$0.00
Grand Total		**-$14,278.58**

ERTH Power Godercih Rate Zone		DVAD		Non-WMP		GA		CBR Class B
Rate Class	**Unit**	**Rate Rider**	**Unit**	**Rate Rider**	**Unit**	**Rate Rider**	**Unit**	**Rate Rider**
Residential Service Classification	kWh	-$ 0.0023	kWh	$ -	kWh	$ 0.0080	kWh	$0.0002
General Service Less Than 50 kW Service Classification	kWh	-$ 0.0020	kWh	$ -	kWh	$ 0.0080	kWh	$0.0002
General Service 50 To 499 kW Service Classification	kW	-$ 0.7537	kWh	-$ 0.5299	kWh	$ 0.0080	kW	$0.0783
General Service 500 To 4,999 kW Service Classification	kW	-$ 0.2625	kWh	$ -	kWh	$ 0.0080	kW	$0.0476
Large Use Service Classification	kW	-$ 0.2812	kWh	$ -	kWh	$ -	kW	$0.0000
Unmetered Scattered Load Service Classification	kWh	-$ 0.0020	kWh	$ -	kWh	$ -	kWh	$0.0002
Sentinel Lighting Service Classification	kWh	-$ 0.0020	kWh	$ -	kWh	$ -	kW	$0.0000
Street Lighting Service Classification	kW	-$ 0.9017	kWh	$ -	kWh	$ 0.0080	kW	$0.0966

Global Adjustment and the IESO Settlement Process

ERTH POWER uses the Global Adjustment (GA) first estimate provided by the IESO to invoice its customers. This treatment is applicable to all customer classes on Non-RPP with the exception of the Class A customers. The Class A customers are billed the actual GA that is invoiced to ERTH POWER from the IESO. The Class A customers are thus excluded in any of the allocations for the disposal of Global Adjustment variance accounts.

ERTH POWER settles monthly with the IESO for the difference between spot and RPP pricing for RPP customers that are billed Time of Use (TOU) or Tiered pricing. The settlement is filed with the IESO within four business days of month end and uses billed data to calculate a prorated amount of usage for settlement. A true-up calculation is completed every month for the previous months and is then added/subtracted from the next month’s IESO submission. At the end of the fiscal year ERTH Power accrues for any unbilled usage along with the settlement amount with the IESO for this unbilled usage.

ERTH POWER allocates the Class B Global Adjustment between RPP and Non-RPP customers (excluding the 1 Class A Customer) based on actual billed consumption.

ERTH POWER reports to the IESO within four business days of month end the total kWHs purchased from embedded generation within its service territory to calculate total kWhs purchased for the month.

ERTH POWER confirms it uses accrual accounting in its Global Adjustment settlement process.

5.4. Shared Tax Savings

ERTH Power Corporation has completed the 2025 IRM Rate Generator tabs related to tax changes for IRM applications to calculate the savings due to rate payers because of corporate tax saving implemented since the 2013 Cost of Service Decision (EB-2012-0175). The Board determined under the 4th Generation IRM that a 50/50 sharing of the impact of currently known legislated tax changes as applied to the tax level reflected in the Board-approved base rates for a distributor is appropriate. The calculated annual tax changes over the plan term will be allocated to customer rate classes based on the most recent Board-approved base year distribution revenue.

ERTH completed Tab 8: Shared Tax – Rate Rider to calculate rate riders for tax change which indicates a shared tax savings is -$3,252. This tax savings does not produce rate riders that are material and will be posted to ERTH Power Goderich's 1595 account to be disposed of at a later date.

5.5. Retail Transmission Rates

ERTH Power is charged Ontario Uniform Transmission Rates (“UTR”) by Hydro One Networks and the Independent Electricity System Operator, and in turn has Board approved retail transmission service rates to charge end user customers in order to recover the expenses. Based on Hydro One Networks most recent Decision and Rate Order of the Board in the EB-2024-0183 proceeding, the UTRS’s for IESO and HONI effective January 1, 2025 are:

- $6.12/kW/mth for Network Service Rate
- $0.95/kW/mth for Line Connection Service Rate
- $3.21/kW/mth for Transformation Connection Service Rate

Variance accounts are used to track the timing and rate differences in UTR’s paid and RTSR’s billed; they are recorded in USoA Accounts 1585 and 1586. On June 28, 2012, the Ontario Energy Board (the “Board”) issued revision 4.0 of the Guideline G-2008-0001 Electricity Distribution Retail Transmission Service Rates (the “Guideline”). This Guideline outlines the information that the Board requires electricity distributors to file when proposing adjustments to their retail transmission service rates. The guideline was used to adjust ERTH’s RTSRs for 2024.

The billing determinants used on Tab 10: RTSR Current Rates of the 2025 IRM Rate Generator Model were derived from the RRR 2.1.5 Performance Based Regulation filing for the annual consumption in compliance with the instruction to use the most recent reported RRR billing determinants. The billing determinants are non-loss adjusted.
The OEB has provided a model for electrical distributors to calculate and predict the distributor’s specific RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. ERTH has completed the model and included the 2018 historical RTSR Network and RTSR Connection data on Tab 12: RTSR – Historical Wholesale of the 2025 IRM Rate Generator Model. ERTH acknowledges that parties to the proceeding will have an opportunity to review the resulting rates as part of the rate process. A summary of the current and proposed RTSRs from the 2025 IRM Rate Generator are provided in the table below:

Table: Summary of Retail Transmission Rates and Charges:

		Current RTSR		Proposed RTSR		Difference	
Rate Class	**Unit**	**Network**	**Connection**	**Network**	**Connection**	**Network**	**Connection**
Residential Service Classification	kWh	$0.0097	$0.0082	$0.0100	$0.0081	$0.0003	-$0.0001
General Service Less Than 50 kW Service Classification	kWh	$0.0088	$0.0070	$0.0091	$0.0069	$0.0003	-$0.0001
General Service 50 To 499 kW Service Classification	kW	$3.5389	$2.8457	$3.6439	$2.7955	$0.1050	-$0.0502
General Service 500 To 4,999 kW Service Classification	kW	$3.7586	$3.1199	$3.8701	$3.0648	$0.1115	-$0.0551
Large Use Service Classification	kW	$4.1623	$3.5674	$4.2858	$3.5044	$0.1235	-$0.0630
Unmetered Scattered Load Service Classification	kWh	$0.0088	$0.0070	$0.0091	$0.0069	$0.0003	-$0.0001
Sentinel Lighting Service Classification	kW	$2.6781	$2.2504	$2.7566	$2.2100	$0.0785	-$0.0404
Street Lighting Service Classification	kW	$2.6689	$2.2468	$2.7481	$2.2071	$0.0792	-$0.0397

5.6. Price Cap Adjustment

Based on the most recent PEG Report, issued on August 6th, 2024, the OEB has updated the stretch factor assignments for 2025. ERTH Power-Goderich Rate Zone remained in the Stretch Factor Group III with a stretch factor assignment of 0.30%. For the period from 2021 to 2023, ERTH's average actual benchmarked costs were 5.9% lower than the predicted costs for the period based on the PEG econometric model.

Furthermore, as part of the Renewed Regulatory Framework for Electricity Distributors ("RRFE") the Board initiated a review of utility performance per the "Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379)" proceeding. As part of this proceeding the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board". The original PEG Report was issued on May 3, 2013, and established the parameters for use to determine the Price Cap Index for the 4th Generation IRM including: a productivity factor of 0.00% was established, the approach to determine the Industry.

Consistent with the policy determinations set out in the Report of the Board on Rate Setting Parameters and Benchmarking under the RRFE for Ontario's Electricity Distributors (EB-2010-0379) (Issued November 21, 2013 and updated December 4, 2013), the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2025, to be 3.6%. The derivation of this is shown in the following table.

Year	Annual GDP-IPI % Change (Table 1)	Weight	AWE % Change (Table 2)	Weight	Annual IPI	Annual % Change
2022					125.0	
2023	3.7%	70%	3.2%	30%	129.6	**3.6%**

The price cap adjustment as determined in the 2025 IRM Rate Generator Model submitted with this application is based on a Price Cap Index from The Board's letter on June 29th, 2024 of 4.50%, which has been used to determine the 2025 Distribution Rates, as follows:

1. Price Escalator of 3.60%

2. Minus a Productivity Factor of 0.0%

3. Minus a Stretch Factor of 0.30% based on ERTH 's current OEB approved Stretch Factor Group III, and

4. The resulting Price Cap Index of 3.30%

ERTH Power-Goderich Rate Zone proposes 2025 distribution rate adjustments to both the Monthly Fixed Service Charge and Distribution Volumetric Rate for all rate classes reflecting the calculated values that are generated by the 2025 Rate Generator Model.

5.7. Residential Rate Design Transition

On April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. This process will be implemented over a period of four years, beginning in 2016. ERTH Power-Goderich Rate Zone has transitioned to fully fixed rates and no further adjustments or mitigation for low volume consumers is required.

5.8. Additional Rates

ERTH Power-Goderich Rate Zone is not proposing any additional rates outside of those detailed in other sections of the application.

5.9. Regulatory Charges

ERTH Power-Goderich Rate Zone proposes to continue to utilize the previously approved WMS, CBDR and RRRP rates unless otherwise directed by the door. These rates are \$0.0041/kWh, \$0.0004/kWh and \$0.0007/kWh respectively.

5.10. Proposed Rates

A copy of ERTH Power-Goderich Rate Zone's Proposed Tariff Sheet has been included in this application as Appendix N.

5.11. Bill Impacts

As shown in the table, the impact of the Rate Design on the Residential class is marginal.

ERTH Power-Goderich Rate Zone has included bill impacts for the following classes:

- Residential – RPP and non-RPP
- GS<50 kW – RPP and non-RPP
- GS 50-499 kW
- GS 500-4999 kW
- Large Use
- Unmetered Scattered Load
- Sentinel Lighting
- Street lighting

Detailed bill impacts for each rate class are provided in Appendix O. The following tables demonstrate the impact of ERTH Power's IRM application exclusive of the impacts of the New Facility ICM Request:

Table: Summary of Bill Impacts exclusive of ICM Request

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	2,000		CONSUMPTION	
GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	64,700	125	DEMAND	
GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	821,250	1,700	DEMAND	
LARGE USE SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	3,942,000	15,000	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	100		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	657		DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	657		DEMAND	1
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0467	1.0467	136		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0467	1.0467	750		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	136		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	1,000		CONSUMPTION	
STREET LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	27,488		DEMAND	

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.27	3.3%	$ (3.01)	-6.6%	$ (2.85)	-4.8%	$ (2.67)	-1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 2.03	3.2%	$ (9.37)	-11.5%	$ (8.95)	-7.8%	$ (8.39)	-2.6%
GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 17.44	3.3%	$ 267.01	37.5%	$ 273.86	18.1%	$ 309.46	3.0%
GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 135.72	3.3%	$ 2,485.30	35.2%	$ 2,581.18	13.8%	$ 2,916.73	2.2%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,393.69	3.3%	$ (12,679.31)	-24.3%	$ (11,771.81)	-7.0%	$ (13,302.15)	-1.8%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 3.14	3.3%	$ 2.56	2.7%	$ 2.58	2.6%	$ 2.92	2.4%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.41	3.3%	$ (2.60)	-5.3%	$ 23.60	0.7%	$ 26.67	0.7%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 621.36	3.3%	$ 95.04	0.5%	$ 122.20	0.6%	$ 138.09	0.5%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 1.27	3.3%	$ 1.58	4.0%	$ 1.61	3.8%	$ 1.82	2.8%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 1.27	3.3%	$ 3.00	6.6%	$ 3.15	5.3%	$ 3.56	2.2%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.27	3.3%	$ 0.49	1.2%	$ 0.52	1.2%	$ 0.49	0.9%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.27	3.3%	$ (4.43)	-9.3%	$ (4.22)	-6.4%	$ (3.95)	-2.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 25,989.90	3.3%	$ 3,969.27	0.5%	$ 5,105.75	0.5%	$ 5,769.50	0.5%

Table: Summary of Bill Impacts inclusive of ICM Request

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	2,000		CONSUMPTION	
GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	64,700	125	DEMAND	
GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	821,250	1,700	DEMAND	
LARGE USE SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	3,942,000	15,000	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	100		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0467	1.0467	657		DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	657		DEMAND	1
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0467	1.0467	136		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0467	1.0467	750		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	136		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0467	1.0467	1,000		CONSUMPTION	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0467	1.0467	27,488		DEMAND	

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.91	20.6%	$ 3.64	8.0%	$ 3.79	6.4%	$ 3.55	2.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 12.88	20.4%	$ 1.48	1.8%	$ 1.90	1.7%	$ 1.78	0.5%
GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 108.69	20.6%	$ 358.27	50.3%	$ 365.12	24.2%	$ 412.58	4.0%
GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 845.72	20.6%	$ 3,195.30	45.2%	$ 3,291.18	17.5%	$ 3,719.03	2.8%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 8,686.73	20.6%	$ (5,386.27)	-10.3%	$ (4,478.77)	-2.7%	$ (5,061.01)	-0.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 19.56	20.6%	$ 18.98	19.8%	$ 19.00	19.5%	$ 21.47	17.4%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 8.80	20.6%	$ 4.79	9.8%	$ 30.99	0.9%	$ 35.02	0.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 3,872.57	20.6%	$ 3,346.25	17.8%	$ 3,373.41	15.2%	$ 3,811.96	15.1%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 7.91	20.6%	$ 8.22	20.5%	$ 8.25	19.4%	$ 9.32	14.2%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 7.91	20.6%	$ 9.64	21.3%	$ 9.79	16.5%	$ 11.06	6.8%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.91	20.6%	$ 7.13	17.8%	$ 7.16	16.8%	$ 6.71	12.2%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.91	20.6%	$ 2.21	4.6%	$ 2.42	3.6%	$ 2.27	1.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 161,978.54	20.6%	$ 139,957.90	17.8%	$ 141,094.38	15.2%	$ 159,436.65	15.1%

ERTH Power is not proposing rate mitigation. When including the impacts of the ICM Request, a some rate classes experience bill impacts which exceed 10% on a Total Bill basis. With respect to the two Street Lighting and Unmetered Scattered Load bill impact scenarios modelled, ERTH Power submits these customers have the financial wherewithal to absorb the presented bill impacts. With respect to low volume Residential RPP customers, Total Bill impacts 14.2% for Non-RPP customers and 12.2% for RPP customers. These bill impacts are elevated relative to typical Residential RPP customers by virtue of the relatively lower Total Bills of low volume consumers. ERTH Power submits the Total Bill Impact in dollars is reasonable and does not require rate mitigation.

6. Certificate of Evidence

As President of ERTH Power Corporation I certify that, to the best of my knowledge, the evidence filed in ERTH's 2025 Incentive Rate-Setting Application is accurate, complete, and consistent with the requirements of the Chapter 3 Filing Requirements for Electricity Distribution Rate Applications as revised on June 18th, 2024.

I also confirm that internal controls and processes are in place for the preparation, review, verification, and oversight of any account balances that are being requested for disposal.

Respectfully submitted,

Chris White
President
ERTH Power Corporation

Appendix A

ERTH Power
2025 Incremental Capital Module Application

Table of Contents

1. Overview

ERTH Power Corporation ("ERTH Power") has capital investment needs that are not funded through existing distribution rates and hereby applies to the Ontario Energy Board ("OEB") pursuant to section 78 of the Ontario Energy Board Act, 1998, as amended (the "OEB Act"), for orders approving Incremental Capital Module ("ICM") funding through distribution rate riders effective May 1, 2025 through to ERTH Power's next re-basing, planned for 2028 rates.

ERTH Power is requesting ICM Approval to fund the purchase of property, design, construction, and furnishing of a new administrative and operational facility ("New Facility") with an in-service date in Q4 of 2025. This centralized facility will serve as ERTH Power's new Headquarters, replacing existing administrative and operational facilities which no longer meet the needs of ERTH Power and its customers.

ERTH Power is seeking approval for incremental capital funding for the New Facility at a projected cost of $33.4 million, with an annual incremental capital revenue requirement of $2.8 million.

ERTH Power submits that the New Facility meets the OEB's 3-Part ICM Test of Materiality, Need, and Prudence. As such, ERTH Power requests the OEB approve ICM Funding for the New Facility as filed. ERTH Power has completed OEB ICM Models for each of its Main and Goderich rate zones, allocating the capital cost of the New Facility between the rate zones as further described in this evidence. ERTH Power confirms the accuracy of the billing determinants entered into the models, which are consistent with those included within its IRM Models also attached to this application.

ERTH Power's evidence supporting approval of ICM funding for the New Facility is organized into the following sections:

4. **Incremental Capital Module Eligibility**
    4.1. Materiality
    4.2. Need
    4.3. Prudence
5. **ICM Financial Implications**
    5.1. Half-Year Rule, Capital Cost Allowance and PILs
    5.2. Derivation of ICM Rate Riders
    5.3. Deferral and Variance Accounts
    5.4. Bill Impacts

This Application is prepared in accordance with the following OEB policies and guidance:

- Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, dated September 18, 2014;
- Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report, dated January 22, 2016;
- Handbook for Utility Rate Applications (the "Rate Handbook"), dated October 13, 2016;
- Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications issued June 15, 2023 (the "Filing Requirements"); and
- Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods, issued February 10, 2022 (the "ICM Policy Update Letter").

2. Background

2.1. ERTH Corporation

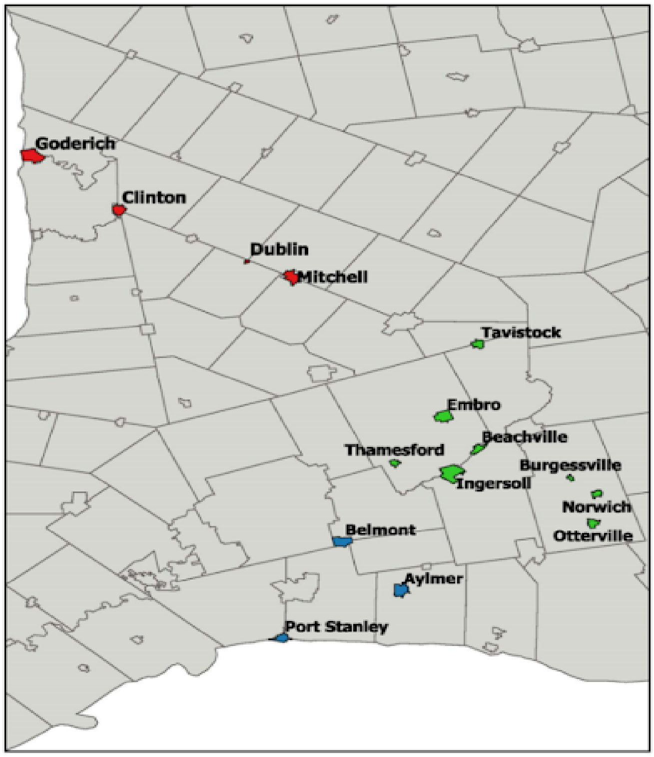
ERTH Corporation ("ERTH CORP") is the municipally-owned parent company for the ERTH Group of Companies. ERTH CORP's vison is to work cooperatively as a trusted, quality service and solutions provider, creating value for all stakeholders. ERTH CORP's mission is to be a community partner, committed to delivering safe and reliable electricity while providing innovative and high-quality services and solutions to its customers. ERTH CORP's corporate values reflect the culture which drives the organization forward; safety first, customer focus, excellence, innovation, sustainability and committed.

ERTH CORP's core asset is ERTH Power Corporation ("ERTH Power"), a regulated local distribution company distributing electricity to 15 communities in southwestern Ontario. ERTH CORP also owns and controls a group of competitive entities that provide a variety of solutions to customers in the utility, municipal, commercial, and industrial sectors across North America. ERTH CORP's competitive business units include ERTH CORP Infrastructure Services and J-Mar Line Maintenance (electrical contracting, traffic and street lighting, high/medium voltage substation commissioning, construction and maintenance services, power line construction and maintenance and electric metering services), ERTH CORP Business Solutions (customer information systems hosting and data management, billing solutions, bill print & stuff, project management and job costing software), and ERTH CORP Business Technologies (retailer billing management services, transaction hub and spoke services for electricity and gas markets).

2.2. ERTH Power

ERTH Power is a regulated electricity distributor delivering electricity to 15 communities spread across four counties in southwestern Ontario. It provides safe and reliable electricity, while focusing on customer needs and energy affordability. ERTH Power strives to provide added benefits and value to its stakeholders by embracing innovation, technology, and community engagement in a way that improves the customer experience and ensures the future sustainability of its business and the communities that it serves. ERTH Power's service territory stretches over 220 km from Port Stanley to the South on the shores of Lake Erie, to its northernmost community Goderich, on the shores of Lake Huron, in addition to serving the communities of Aylmer, Belmont, Ingersoll, Thamesford, Embro, Tavistock, Beachville, Norwich, Otterville, Burgessville, Port Stanley, Mitchell, Dublin, and Clinton. In these communities, ERTH Power's diverse customer base ranges from residential and small business customers to large commercial and industrial users, including Compass Mineral's Sifto Salt Mine in Goderich, Integrated Grain Processers Cooperative (IGPC) in Aylmer, and General Motor's CAMI Automotive Assembly Plant in Ingersoll. ERTH Power is typically a summer electricity load peaking utility at approximately 100 MW over the 2021-2023 period.

Figure 1: ERTH Power Service Territory Map



ERTH Power, formed in 2000 through the merger of seven municipal utilities, initially served 14,000 customers and maintained 290 km of distribution power lines across 11 communities. Over the course of 20 years, the company experienced organic growth within these communities and underwent three mergers with neighboring utilities in 2010 and 2019. As a result, ERTH Power now caters to approximately 32,819 customers across all Rate Classes and manages 453 km of distribution power lines spanning 15 communities.

3. ERTH Power New Facility

3.1. Facilities Overview

As noted above ERTH Power, currently rents its facilities from ERTH CORP; including the Bell St. property, and a satellite operations centre located on Elm St. in Aylmer, Ontario. The following sections detail the characteristics of each of these facilities, and ERTH Power's usage of them:

3.1.1.Bell St. Property

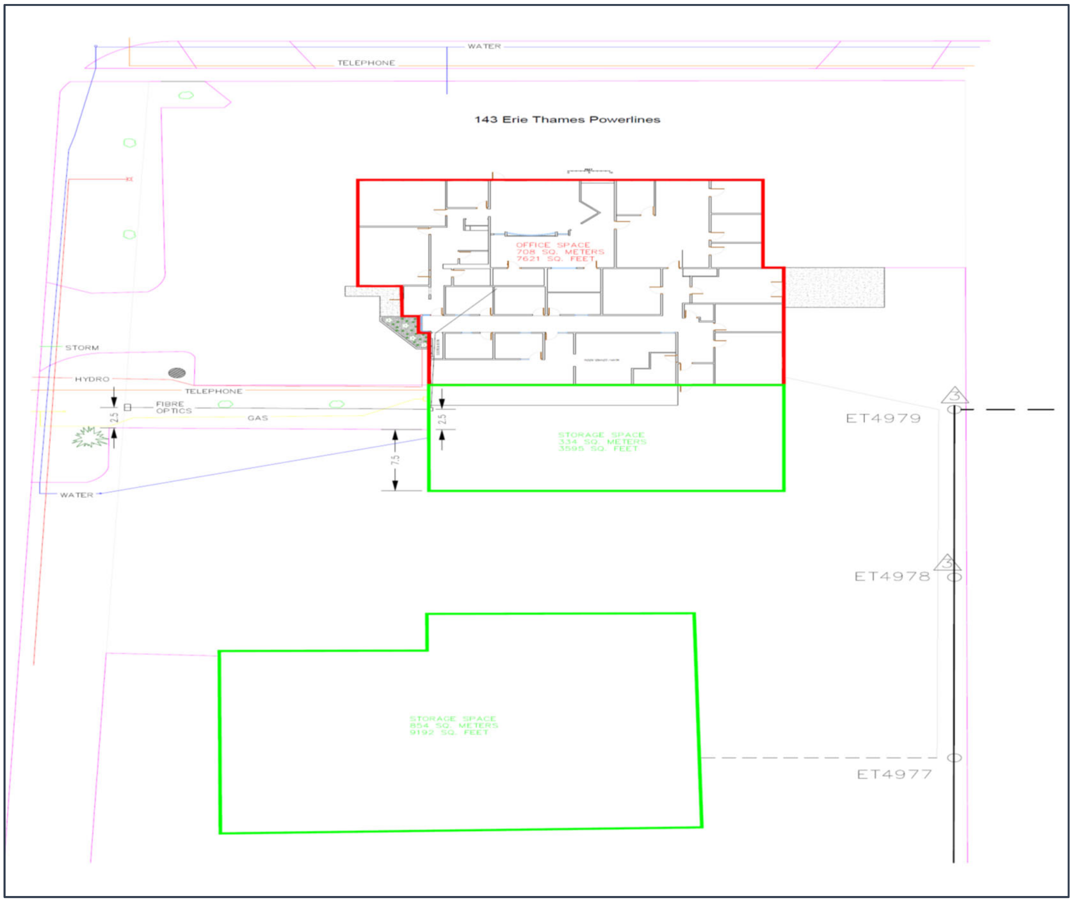
The Bell St Property sits on approximately 1.8 acres of commercially zoned land located in a primarily residential neighbourhood of Ingersoll. It is a multi-purpose facility and is the headquarters for ERTH Power, with the following uses:

- ERTH Power headquarters, with requisite administrative office facilities;
- In-person customer service desk;
- an operations and service centre housing 4 heavy and 10 light fleet vehicles;
- garage and maintenance services for all of ERTH Power's fleet vehicles; and,
- ERTH Power's primary facility for indoor and outdoor inventory storage.

Currently, 32 Full Time Equivalent (FTE) ERTH Power staff operate out of this facility.

Figure 1 below is an engineering drawing of the Bell St. property footprint. The property has an office facility of approximately 7621 ft2 in area, an operations space of 3595 ft2, and a mixed operations and storage space of 9192 ft2.

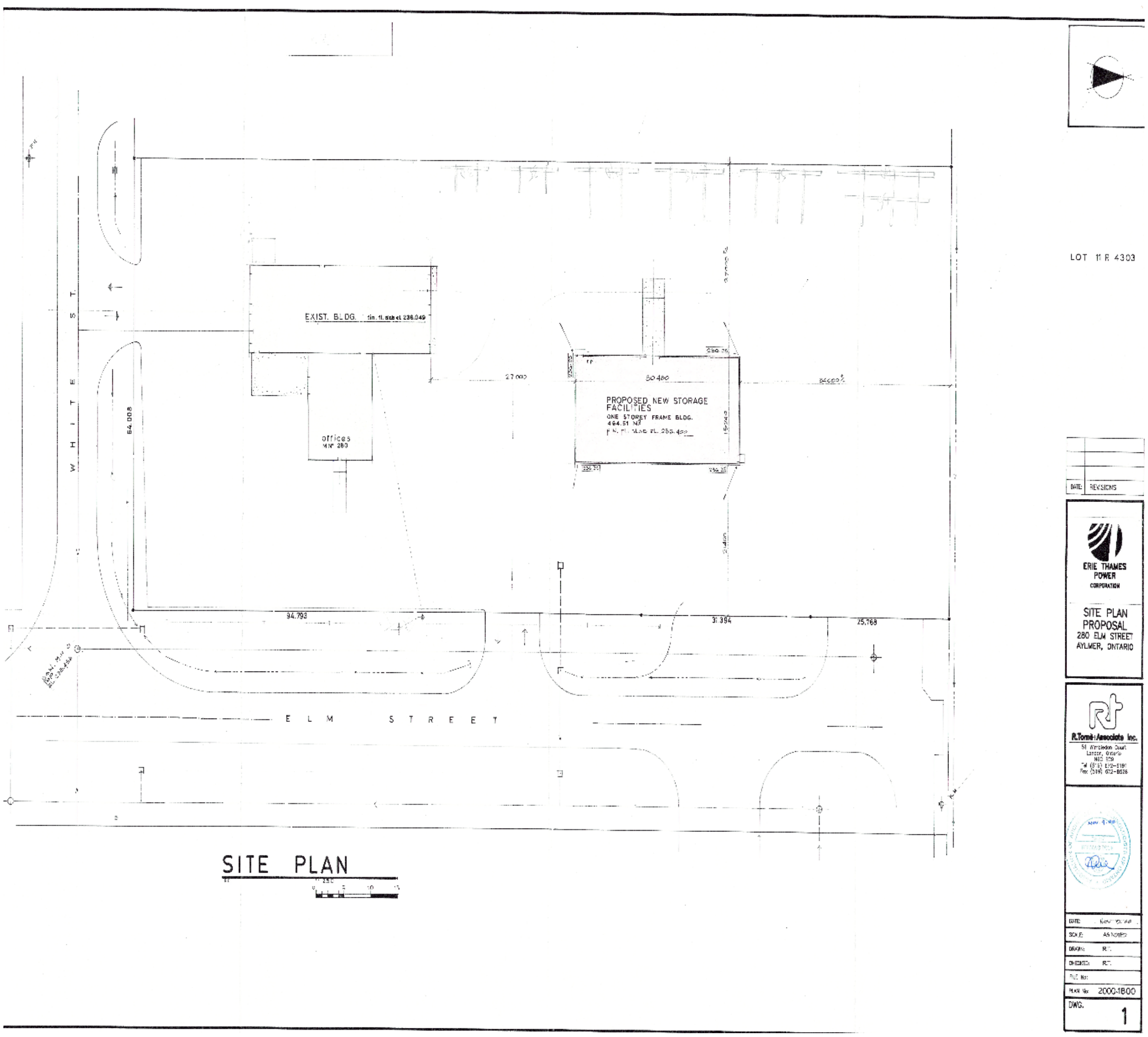
Figure 2: Bell St. Property Site Plan



3.1.2.Elm St., Aylmer Property

The Elm St. property in Aylmer Ontario (Aylmer Property) is located approximately 32 Km from the Bell St. Property, and sits on approximately 2.4 acres. It serves as a satellite operations centre for four staff, 3 heavy fleet, 3 light fleet, an operations centre, administrative offices and equipment storage. Figure 2 below is an engineering diagram of the Aylmer Property:

Figure 3: Aylmer Site Plan



3.2. Challenges and Requirements

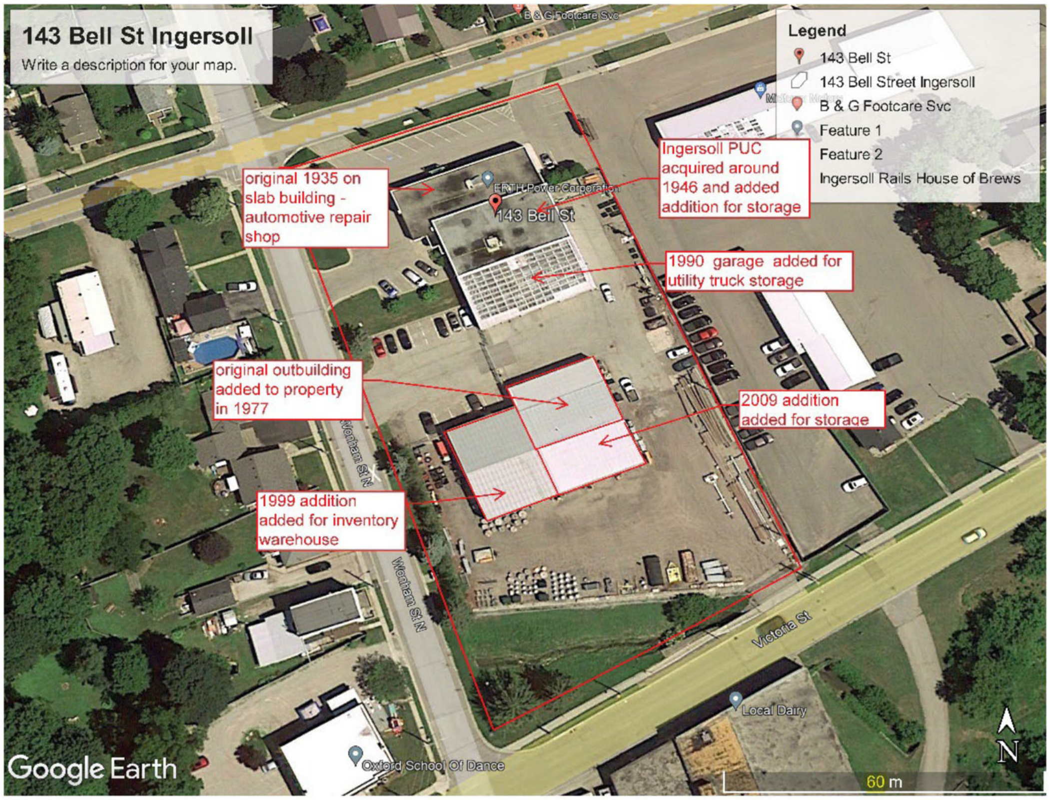
3.2.1.Bell St. Property Challenges

The primary challenge with the Bell St Property is one of available space, with the customer base and serviced distribution line of the utility having approximately doubled since the creation of ERTH Power in 2000. Having worked within this constrained space during a high-growth twenty-year period, there is no longer any opportunity for ERTH Power to optimize or expand its operations centre, or fully repatriating its staff into one building at the Bell St Property.

To maximize use of the property over past decades and meet the basic needs of its current staffing compliment, the Bell St. Property has undergone a number of additions and modifications to the original building dating back to 1935. The multiple expansions and modifications over the property's 87-year life have resulted in mounting issues, such as highly constrained space for heavy fleet maneuvering and multiple electric service entrances.

With respect to geography, the 1.8-acre site has a natural slope from north to south, and the southern edge of the Bell St. Property sits on a natural flood plain (approx. 0.3 of the 1.8 acres) which limits any ability for expansion into the remaining open space. This sloping also presents the risk of contamination of a natural waterway in the event an environmental spill were to occur.

Figure 4: Bell St Property Aerial View & Chronology of Modifications



Relative to ERTH Power's requirements, the Bell St. Property has reached the end of its useful life given the building age and condition, as well as significant indoor and outdoor space limitations. While the Bell St. Property has numerous shortfalls relative to requirements, as outlined below, principally ERTH Power requires larger and more purpose-built facilities and property for operations and storage to improve the safety and effectiveness of its core workload. The most pressing needs driving ERTH Power to seek relocation from the Bell St. Property are summarized below:

- **Fleet Maintenance**: ERTH Power fleet operations and staging are split across two separate facilities, neither of which is optimally designed or sized for ERTH Power's current operational requirements. As a result, tasks and materials are unnecessarily reduced in efficiency, and many routine fleet maintenance activities must be completed outdoors.
- **Fleet Maneuverability**: The size and location of the building envelopes on the property significantly hinder ERTH Power's heavy fleet vehicles' ability to complete basic maneuvers into, out of, and

around the property. This reduces overall efficiency and effectiveness of basic operations, including emergency operations, and places extraordinary wear-and-tear on tarmac surfaces due to heavy-vehicle, multi-point turns. Finally, the constrained space creates extreme challenges for large-truck, third party deliveries of supplies and materials to the facility, which further hinders ERTH Power's fleet and outdoor storage during delivery.

- **Outdoor Storage:** The Bell St. Property has extremely limited space for outdoor storage of large distribution components such as poles and transformers, resulting in sub-optimal organization of and access to these materials with impacts on efficiency. Any attempt to increase outdoor storage would subtract from space available for fleet maneuverability, which is already below basic requirements.
- **Safety:** One implication of the current outdoor space configuration is an increased risk to safety. Building configuration creates multiple blind spots between vehicles and pedestrians within the constrained yard, and the required storage conditions for poles recently led to a near-miss safety incident.
- **Multiple Electrical Service Connections:** Current distribution connection configuration renders ERTH Power unable to electrify its fleet as the energy transition advances, and the cost to reconfigure and consolidate these connections would be high.
- **Upcoming Maintenance & Investments:** The existing main building and outbuildings will require roof repairs within the next 5-10 years, while some of the Bell St. Property HVAC units are scheduled to be replaced within the next 5 years.
- **Control Room:** Due to the fragmented and largely structural nature of the building, the current control room lacks physical security and separation from the general office space of the building, inconsistent with utility best practice. Further, the current configuration does not have an optimal or readily available War Room adjacent to the control room to facilitate improved emergency response and coordination.
- **Server Room:** The server room currently lacks adequate temperature control and fire suppression relative to best practice.
- **Office Staff Requirements:** Interior office space is restricted for growth, and its fragmented layout limits the ability for staff collaboration and overall efficiency. Lacking any available outdoor space to spare, there is no green space for staff, nor is there any opportunity to create such. As the labour

market is anticipated to remain tight through most or all of the 2020's, the environment provided at Bell St. no longer meets basic office employee expectations relative to competitors. In addition, employee parking is near full capacity, with no opportunities for expansion.

- **Field Staff Requirements:** Field staff locker rooms, lunchroom and washrooms are inadequate and uninviting for a growing work force. ERTH Power has made best efforts to improve these facilities, however the physical and structural layout of the building provides limited cost-effective opportunities to significantly improve workplace conditions for field staff, including the persistent need for pest control.
- **Training:** The Bell St. Property does not have a room capable of facilitating full staff training events to maintain the working knowledge and effectiveness of both office and field staff. For mid-to-large training sessions, the truck bays must be cleared to provide a make-shift training space for staff. For full-sized training, third-party offsite accommodations must be arranged.

3.2.2.Aylmer Property Challenges

The challenges associated with the Aylmer Property are largely limited to staffing and human resource issues, and the cost of operating a second operations centre of this size. ERTH Power's rent for the full Aylmer Property in 2023 was $92k.

The Aylmer operations centre has seen significant turnover of powerline technicians in recent years, and has tracked to a higher level of health and safety incidents relative to ERTH Power's overall operations over the past four years. ERTH Power management has noted the challenge of staff not benefiting from the day-to-day leadership and mentoring that would otherwise arise from their working in a centralized operations centre. The relative size of ERTH Power's distribution plant proximate to the Aylmer Property creates a challenge in that assignment of sufficient frontline leadership to the location would largely be for the purpose of staff management, as opposed to operational need. Additionally, the pool of operations staff candidates is significantly smaller in the Aylmer area relative to the Ingersoll and area; particularly given Ingersoll's favourable proximity to Highway 401.

Additionally, the Aylmer Property has chronic roof issues leading to water damage, no change rooms or shower facilities, and requires upgrades to office and operations spaces to provide an ergonomic and modernized facility.

3.2.3. Requirements

ERTH Power has determined that addressing the challenges associated with its Bell St and Aylmer Properties is best performed through a consolidation of both facilities into a new Operations and Administrative property (New Facility).

As noted above, the decision to move to the New Facility is primarily driven by an assessment that the Bell St. Property has reached the end of its useful life relative to ERTH Power's needs. However, construction of the New Facility will allow for achievement of multiple additional objectives, such as:

- Sufficient outdoor land for optimal outdoor storage and fleet maneuverability in the present, and to allow for future expansion of facilities, infrastructure and amenities as required;
- Improved safety through optimal outdoor storage and operations space;
- Purpose-built indoor fleet and maintenance facilities, improving efficiency and effectiveness of overall operations, including ability to store heavy fleet indoors and extend vehicle useful lives, reducing depreciation expense over time;
- Purpose-built, utility best practice Control Room, with physical security and adjacent War Room to facilitate optimal emergency response and coordination;
- Improved workplace conditions for both office staff and field staff, to improve retention and recruitment in a tight labour market, including sufficient parking capacity with opportunities for expansion as needed, and required training facilities to maintain a state-of-the-art workforce;
- Repatriation of Aylmer Property staff to reduce health and safety incidents, and improve leadership and mentoring opportunities, and as a result operational effectiveness;
- Opportunity to reduce fleet size in the short term (potentially by 1 heavy and 2 light vehicles) through repatriation of Aylmer Property staff and facilities to a central ERTH Power headquarters;
- Ability to reduce cost of rent (Bell St. Property to 0%, Aylmer Property to 50% for use as job and emergency staging) through consolidated operations. ERTH Power recognizes that the cost of rent is currently embedded within its approved rates. ERTH Power is open to innovative ways to recognize the savings on rent charges within the confines of an ICM application;
- Optimal access to distribution capacity to allow for modernization and electrification of ERTH Power's fleet in the future; and,
- Ability to participate in the energy transition and reduction of greenhouse gas emissions, through the combination of a ground-source heat pump system and a solar photovoltaic system, yielding reduced operating expenditures.

To achieve these objectives, Table 1 – Facility Specification identifies the major specifications required of a New Facility:

Table 1: Facility Specification

New Facility Characteristic	Specification
Geography / proximity to broader service territory	• Location near major roadways. • Location in larger population centre to support employee recruitment and retention
Need for future expansion acreage, if applicable	• Larger land footprint/acreage to allow for office expansion arising from future growth • Infrastructure to support full electrification of fleet and employee vehicles
Min fleet capacity	• Current 20 fleet vehicles comprised of 7 large and 13 smaller fleet vehicles • Service bays for up to five fleet vehicles • Sufficient outdoor land for optimal outdoor storage and fleet maneuverability • Indoor fleet and maintenance facilities that provide for efficient and effective operations, including ability to store heavy fleet indoors and extend vehicle useful lives
Training facilities	• Ability to conduct an all-employee town hall • Facilities to perform in-class operations training
Requirements for employee effectiveness and retention	• Increased parking for employee vehicles with support for future electrification • Functional shower and washroom facilities for operations staff • Training room facility, common lunch room and outdoor space, general brightness with sufficient natural light

New Facility Characteristic	Specification
	penetration to office space areas, ventilation optimized for air quality purposes. • Drying room for operational staff clothing after being out in all weather conditions (rain/snow) storm response
Min FTE capacity	• Current staffing of ERTH Power of 38 FTE, and ability to support up to 50 FTE in total [1]
Control room and server facilities	• Fully secured and segregated control room • Expandable and zone-based climate-controlled server facilities

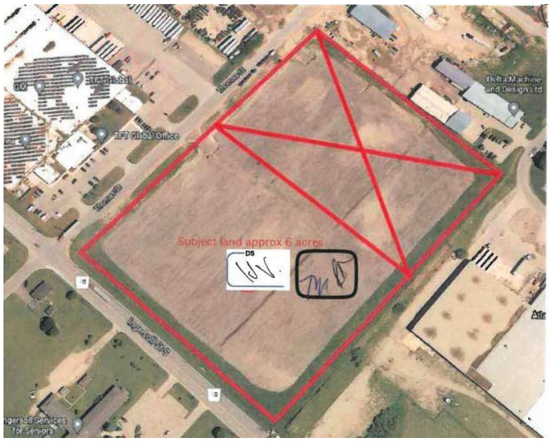
3.3. New Facility Project Description

A key requirement of the New Facility is selection of an optimal property that is in the appropriate location, is cost-effective, and provides sufficient land size to accommodate current requirements and future expansion. ERTH Power determined that Ingersoll is the optimal location for the New Facility. Ingersoll provides a logistically efficient and cost-effective location to service ERTH Power's customers given it is the most central location within its wide and discontinuous service area. In addition to being an efficient location to service multiple communities in Oxford County, an Ingersoll location also provides easy access to major roadways in and around the County[2].

In early 2023, ERTH Power's conditional offer to purchase land in Ingersoll for its New Facility was accepted by the property seller. The six-acre property is located at 385 Thomas Street (New Land), which is pictured below and currently used for parking vehicle overflows by the nearby General Motors CAMI plant.

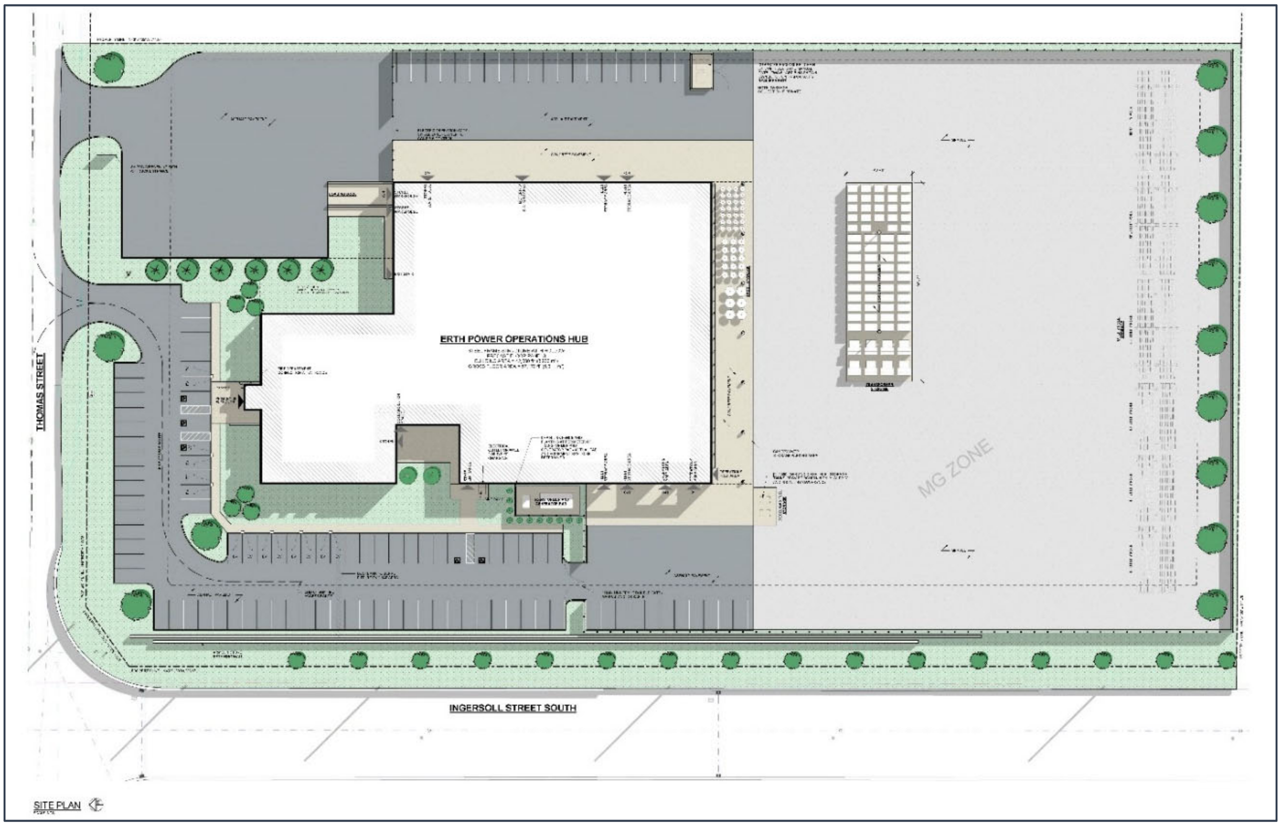
[1] ERTH Power will rent space to ERTH CORP (i.e. At minimum 12 ERTH CORP FTE)
[2] Ingersoll is in close proximity to Highway 401, Highway 19, and County Road 6 and allows the Ingersoll staff to support after hour emergency response and other work at the remote locations.

Figure 5: Aerial Pictures of 385 Thomas Street Location



ERTH Power commissioned Powell Engineering to produce an engineering design of the New Facility that meets its requirements and mitigates the challenges noted above with the Bell St and Aylmer Properties. The New Facility is being designed to be a serviceable operations and administrative center that once completed, will house ERTH Power's employees and generate rental income from ERTH CORP. ERTH Power's New Facility will have a two-storey administrative area that is adjacent to a warehouse, metering and fleet vehicle service area. The building footprint is approximately 1 acre or 42,399 ft2 in area, totalling 50,624ft2 in total floor space across two stories. It will include space for training, server and control rooms, as well as a meter station work area and sufficient warehouse space for storage of inventory. The distribution ft2 across uses is approximately 13,439ft2 of office space, 13,965ft2 of operational space, and 23,221ft2 of indoor storage. Figure 5 below depicts the site plan of the New Facility:

Figure 6: New Facility Site Plan



Powell Engineering has proposed an ergonomic, economical and sustainable design. The design provides for future expansion of the New Facility when necessary, and as shown above, the New Facility design provides ample space for outdoor storage of transformers, poles and other large distribution assets. The New Facility will support storage and maintenance of ERTH Power's 20 fleet vehicles, and 44 FTE at present, with an expectation of additional ERTH Power FTE being required in the coming years. Additionally, through a rental services agreement with ERTH CORP, the New Facility will also support approximately 10 additional ERTH FTE. The ERTH corporate employees will operate out of the New Facility and provide services to ERTH Power amongst other entities. This reduces ERTH Power's FTE's and allows it to operate at a lower cost.

The New Facility's operational storage space and fleet storage area is being designed to balance ERTH Power's inventory procurement, and warehousing requirements. It includes staging areas for project specific work, as well as storm response. The New Facility fleet storage area has been designed to allow for fleet ready electrification with EV charger installations, and indoor storage for emergency response to potential failures at any of ERTH Power's 10 substations. The New Facility operations building segment has a modicum of space for a small increase in the number of fleet vehicles without the need for incremental capital expenditures to expand the building.

3.3.1. New Facility Financial Summary

ERTH Power's cost of land as presented below is $6.2 million. Construction is planned for completion in Q4 of 2025; providing for an in-service date in 2025. The full cost of building construction including finishes, fixtures and furniture is forecast at $27.2 million, which includes $1.5 million for a solar photovoltaic system, and $4.2 million to install a ground-source heat pump system in lieu of conventional heating and cooling. A breakdown of the New Facility capital expenditures is provided below, and has been entered into the ICM models accompanying this application:

Table 2: New Facility Costs

Component	$000's
Land	$6,217
Yard	$462
Building	$13,899
Furniture, Fixtures & Equipment	$1,784
Mechanical & Energy Systems	$11,077
Total	**$33,439**

The table below summarizes the incremental revenue requirement resulting from approval of the capital expenditures associated with the New Facility, which is allocated to ERTH Power's Main and Goderich rate zones as further described in this evidence:

Table 3: Incremental Revenue Requirement

Component	Main RZ ($000's)	Goderich RZ ($000's)	Total ($000's)
Return on Rate Base	$1,618	$383	$2,001
Amortization Expense	$632	$145	$777
Gross Up Taxes/PILs	$0	$0	$0
Total	**$2,250**	**$528**	**$2,778**

3.4. Options Analysis

In making its decision to pursue the most cost-effective option to meet its operational needs, ERTH Power completed an assessment of available facility alternatives. ERTH Power considered as part of this process purchasing an existing building and property and retrofitting it to meet its operational needs. There were no feasible options available within Ingersoll (the most effective and efficient location of the operations centre to service ERTH Power's territory) to include as a viable option. The table below compares costs and outcomes across three Options:

1) **Do-Nothing Option:** ERTH Power continues to headquarter operations at the Bell St. Property under lease from ERTH CORP, and ERTH Power continues to make rental payments to ERTH CORP for its primary operations and administrative centre. The Aylmer Property continues to be utilized/rented at 100% capacity.

2) **Lease Option:** ERTH Power pursues a lease arrangement at the only available commercial / industrial space in Ingersoll at 100 Newman St. Use/rental of the Aylmer Property is down-sized to 50%, and is used for storage and operational staging in the region. ERTH Power receives rental payments from ERTH CORP for use of a portion of its new operations and administrative centre. HVAC choices are assumed to be conventional (i.e. natural gas heating and conventional electric A/C).

3) **New Build Option:** ERTH Power procures the new property at 385 Thomas St., and constructs the new building described in this evidence. Use/rental of the Aylmer Property is down-sized to 50%, and is used for storage and operational staging in the region. ERTH Power receives rental payments from ERTH CORP for use of a portion of its new operations and administrative centre. Solar photovoltaics and a ground-source heat pump system are installed, reducing operating costs and making ERTH Power an active participant in the energy transition.

The following table compares these three options across essential metrics of cost and outcomes:

Table 4: Facility Options Analysis

Metric	Option 1: Do Nothing	Option 2: Lease	Option 3: New Build
2025 Capital Expenditures	$0[3]	$9.6M[4]	$33.4M
2025 to 2044 NPV of Revenue Requirement[5]	$8.3M	$32.2M	$32.9M
Acres[6]	4	9	6
ft2[7]	30,963	118,732	55,902

[3] No inclusion of near-term need for new roof, new HVAC, reconfiguration of grid connection for electrification, or health and safety related upgrades

[4] Building available for rent is largely a shell building, requiring substantial investment to retrofit for both office use and operational use

[5] No inclusion of re-investment in assets with expiring EUL within analysis period; assumes use of 2024-2027 wind-down Accelerated CCA; ERTH current weighted cost of capital parameters used to determine revenue requirement, and used as Weighted Average Cost of Capital for discount rate

[6] Including 100% of Aylmer Property in Option 1, and 50% of Aylmer Property in Options 2 and 3

[7] Excluding ft2 rented by ERTH Corp where applicable in Options 2 and 3. Includes 100% of Aylmer ft2 in Option 1, and 50% of Aylmer ft2 in Options 2 and 3

Metric	Option 1: Do Nothing	Option 2: Lease	Option 3: New Build
Fleet Accommodation	Fleet maintenance and staging capabilities are disbursed across two buildings on the property. Some maintenance activities must be completed outdoors. Highly constrained mobility of heavy fleet due to lack of open space, resulting in lost time for turnarounds and heavy wear on yard surfaces due to multi-point turns. Limited opportunity for indoor storage of fleet	Fleet maintenance and staging capabilities are centralized and optimized. All maintenance can be completed indoors where safe to do so. Reasonable mobility of heavy fleet within small yard available, with limited lost time for turnarounds or wear on yard surfaces due to multi-point turns. Optimal opportunity for indoor fleet storage, increasing EUL of fleet and improving fleet readiness in cold conditions	Fleet maintenance and staging capabilities are centralized and optimized. All maintenance can be completed indoors where safe to do so. Optimal mobility of heavy fleet within ideally sized yard, with no lost time for turnarounds or wear on yard surfaces due to multi-point turns. Optimal opportunity for indoor fleet storage, increasing EUL of fleet in cold conditions
Outdoor Storage	Highly constrained outdoor storage for large components such as poles and transformers. Conditions result in sub-optimal access and delays in crew staging, as well as increased possibility of safety incidents such as recent pole-storage related near-miss. Lost time due to coordination of basic heavy fleet movement and material staging activities. Sub-optimal leverage of offsite storage required, creating lost time	Highly constrained outdoor storage for large components such as poles and transformers. Increased leverage of offsite storage will be required, increasing lost time. Conditions result in sub-optimal access and delays in crew staging, as well as increased possibility of safety incidents. Lost time due to coordination of basic heavy fleet movement and material staging activities. Sub-optimal leverage of offsite storage required, creating lost time	Optimal size and organization of outdoor storage for large components such as poles and transformers. Access to required materials is optimal, with no unnecessary lost time and minimized opportunities for safety incidents. Coordination between heavy fleet movement and material staging is not required. Offsite storage is not required, aside from instances where it is more effective due to job proximity
Control Room	Control room is functional. Physical restrictions and security are not possible due to structural building layout. No ability to structure adjacent war room for emergency events	Control room is optimal. Optimal physical restrictions and security are in place, and build-for-purpose war room is available for emergency events	Control room is optimal. Optimal physical restrictions and security are in place, and build-for-purpose war room is available for emergency events

Metric	Option 1: Do Nothing	Option 2: Lease	Option 3: New Build
Field Staff Space	Field staff locker rooms, lunchroom and washrooms are inadequate and uninviting for a growing workforce. No opportunity for expansion or meaningful retrofit due to structural restrictions	Field staff locker rooms, lunchroom and washrooms are optimal, with opportunity to expand facilities as needed for a growing workforce	Field staff locker rooms, lunchroom and washrooms are optimal, with opportunity to expand facilities as needed for a growing workforce
Training Space	Challenging environment to facilitate training necessary for safe and effective operations. Full-scale training requires use of heavy truck bays, or use of third-party institutional space	Ample opportunity to design, build and utilize optimal training space	Ample opportunity to design, build and utilize optimal training space
Office Staff Space	Raw ft2 available to administrative staff is sufficient. Layout is disjointed, impacting collaboration and productivity. No opportunity for greenspace or similar to facilitate retention	Raw ft2 available to administrative staff is sufficient, and layout is optimally designed. Limited opportunity for greenspace or similar to facilitate retention	Raw ft2 available to administrative staff is sufficient, and layout is optimally designed. Ample opportunity for greenspace or similar to facilitate retention
Fleet Electrification	Grid connection is disparate across 3 differently configured connection points, with insufficient capacity to allow for electrification of light or heavy fleet. Reconfiguration of connection and capacity expansion is understood to be costly	Grid connection is ideal and capacity is sufficient for full electrification of fleet if and when required	Grid connection is ideal and capacity is sufficient for full electrification of fleet if and when required

Metric	Option 1: Do Nothing	Option 2: Lease	Option 3: New Build
Expansion Opportunities	No opportunity for expansion. Current staff and fleet contingent exceed capabilities of facility	Opportunity for expansion. Expansion will come at the expense of fleet or material storage, which could necessitate additional offsite storage or additional fleet centres in the future	Opportunity for expansion. Expansion will come at the expense of outdoor material storage space, which is ample

Based on a comparison of the Options outlined above, **Option 1: Do Nothing is not a viable solution** to meet ERTH Power's facility needs moving forward. Reasons for the exclusion of this option as viable include, but are not limited to:

- **Operational effectiveness** will continue to be hindered indefinitely if ERTH Power continues to maintain primary operations and administration from the Bell St. Property. Fleet storage, maintenance, and readiness are severely hindered at the Bell St. Property, which collectively impacts ERTH Power's ability to respond to emergency and non-emergency incidents in a timely manner, and negatively impacts the EUL of both fleet vehicles and yard surfaces; increasing maintenance costs on both fronts. Similarly, sub-optimal outdoor storage for large distribution components negatively impacts job staging, which creates lost time.

- **Safety** is sub-optimal, and in some cases compromised, continuing to operate out of the Bell St. facility. The tight outdoor space available at the Bell St. Property creates opportunities for lost-time incidents, including the recent occurrence of a near-miss relating to sub-optimal storage conditions for distribution poles. Lack of maneuverability and visibility for large fleet creates opportunities for dangerous employee-to-vehicle contact, which can be exacerbated where third-party deliveries are attempted in the constrained yard. While ERTH Power does not anticipate a physical security breach relating to its control room, the current physical layout does not allow for good utility practice of creating physical restrictions to critical system controls, as well as ready access to a functional war room for emergency events.

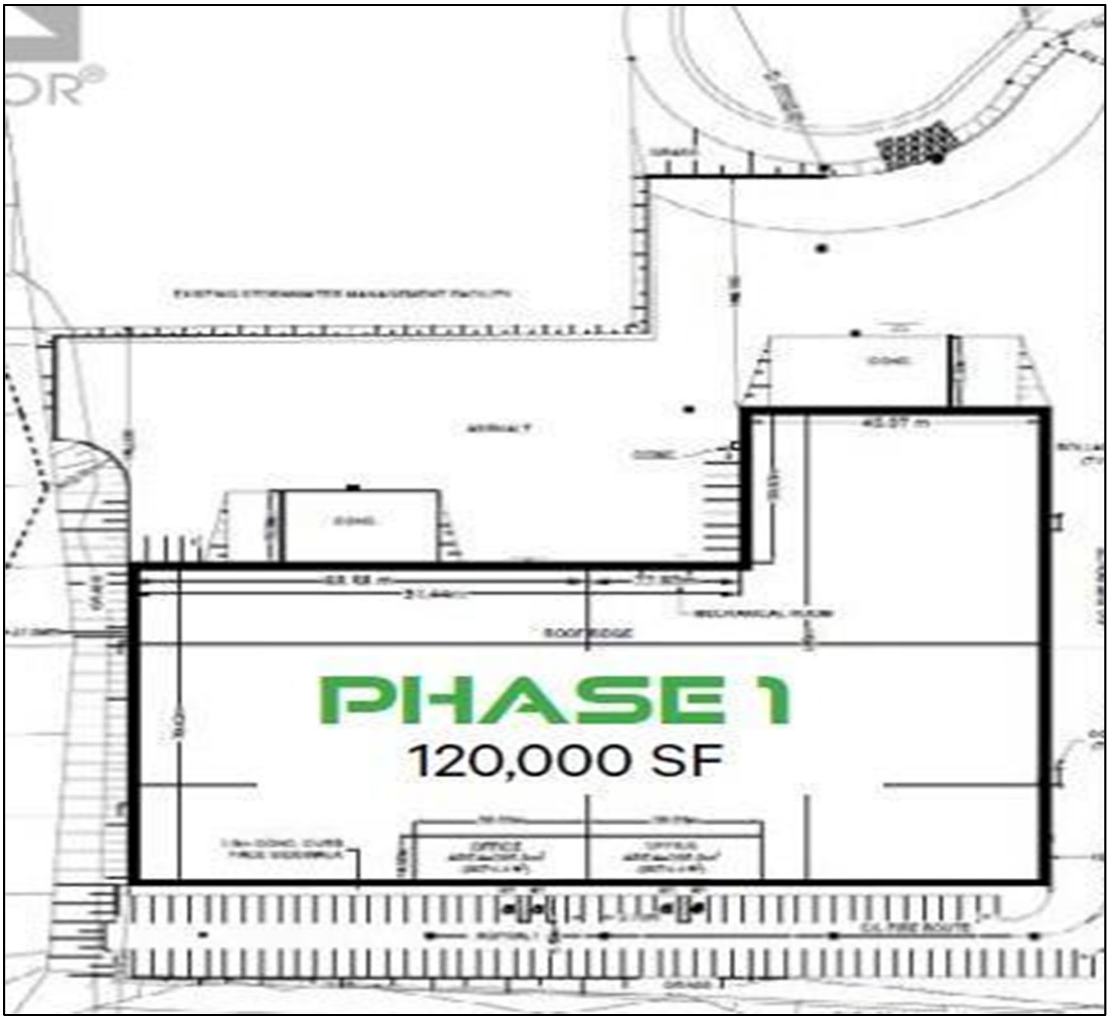
- **Staffing** has increasingly become a challenge for many distributors in Ontario, with little sign of workforce alleviation as peak baby boomer retirement trends continue. In order to maintain a sufficient and capable workforce, ERTH Power requires facilities which meet the basic expectations of employees in the 2020's. This includes locker rooms, washrooms, and common areas with basic levels of functionality and appeal to retain field workers, as well as functional and collaboratively-designed office spaces for administrative workers. Similarly, ERTH Power requires adequate training facilities to maintain a workforce that is educated and prepared to respond to the present-day challenges of electricity distribution, which requires adequate training facilities to accommodate.

- **Future** needs of ERTH Power are anticipated to continue to evolve. Expanded facility needs could be driven by natural customer growth as immigration to Canada continues at historic highs, or acquisition-driven growth as the Government of Ontario continues to express interest in further distributor consolidation. Similarly, whether in response to customer preferences, business decisions, or government mandates, ERTH Power anticipates the electrification of increasing proportions of its fleet over time. The primary facility of ERTH Power must be able to accommodate changing circumstances moving forward, and the Bell St. Property has exhausted all opportunities to grow and evolve with the utility.

In assessing potential options to meet ERTH Power's facility needs, **Option 2: Lease** presents itself as a technically viable, but clearly sub-optimal solution. Reasons detracting from selection of this option include, but are not limited to:

- **Yard availability** at the potential lease property is highly limited. While the property appears to allow for ample maneuverability of heavy fleet as needed, there is little opportunity for outdoor storage of large distribution components such as poles and transformers. To accommodate storage of these materials, ERTH Power would be required to constrain the available yard in a manner that returns the utility to a position of yard restriction, negating one of the primary benefits of relocating from the Bell St. Property. This restriction also has implications for expansion opportunities**,** as the current outdoor space is sub-optimal even at current operational requirements. The figure below depicts the available yard relative to the lease building analyzed:

Figure 7: 100 Newman Rendering



- **Available options** for appropriate lease properties are highly limited to ERTH Power. ERTH Power does not operate in an urban or suburban environment in which multiple, appropriate properties are available for lease by the utility. The property analyzed is the only somewhat viable property available for lease in Ingersoll which meets some (but not all) of the needs of a mid-sized electricity distributor. Unsurprisingly, the only somewhat viable available lease property to ERTH Power in Ingersoll is not optimally designed for an electricity distributor, with far too much indoor space and too little outdoor space. While in theory ERTH Power could extend its search beyond Ingersoll, its location close to the 401 highway and centralized location relative to ERTH Power's service territory necessitates that a central, administrative and operational centre be located in Ingersoll.

- **Cost:** In large part due to the issue of Available Options outlined above, the Lease Option is immaterially less expensive for ratepayers relative to a New Build, despite providing sub-optimal outcomes on numerous fronts. This is a 120,000ft2 facility, which is more than double the New Build option planned. The size of this facility drives significant costs which render it materially the same cost as a New Build, with sub-optimal operational outcomes.

In contrast to Options 1 and 2, **Option 3: New Build** meets all of ERTH Power's facility needs, at a reasonable expense to ratepayers relative to the alternatives, while yielding improved capabilities to the benefit of ratepayers. Option 3: New Build responds to all of the limitations of Options 1 and 2, in the following ways:

- **Operational effectiveness and yard availability** will be maximized through a purpose-built administrative and operational headquarters for ERTH Power. Where ERTH Power's needs are explicitly incorporated into design, optimal outcomes are ensured with respect to outdoor storage, indoor fleet maintenance and storage, and an overall maximization of job staging efficiency to improve response time.

- **Safety** is maximized through Option 3: New Build, as operational facilities will be designed to explicitly limit opportunities for safety incidents, be they related to vehicles or the storage and handling of distribution components. Similarly, a custom-built control room and adjacent war room will allow for the realization of utility best practice in this area.

- **Staffing** can be optimally retained and enhanced where ERTH Power purpose-builds a facility which provides adequate facilities for both field and administrative staff, such that their place of work is competitive with other opportunities available to them. Similarly, a new build which explicitly contemplates adequate training facilities will ensure the education and effectiveness of ERTH Power's workforce in the long-term.

- **Future growth and expansion opportunities** can be optimally planned for through the construction of the new building planned by ERTH Power. With an appropriate and adequate grid connection, ERTH Power's Thomas St. facility will be capable of accommodating fleet electrification as this becomes necessary for the utility. Similarly, should customer growth or acquisition-related growth require it, the Thomas St. property will allow for prudent facility expansion in a manner than does not compromise operational outcomes.

An analysis of the options above demonstrates that **Option 3: New Build** is the most cost effective solution for ERTH Power and its customers, providing the best value of available viable options to meet the utility's facility needs.

3.5. Benchmarking

In order to assess the relative reasonableness and prudence of ERTH Power's New Facility, a benchmarking analysis was completed which compared the new building to those of other mid-sized distributors in Ontario in recent years, across a variety of metrics. The peer group chosen for the purpose of this analysis was as follows:

Table 5: Ontario Facility Benchmarking Peer Group

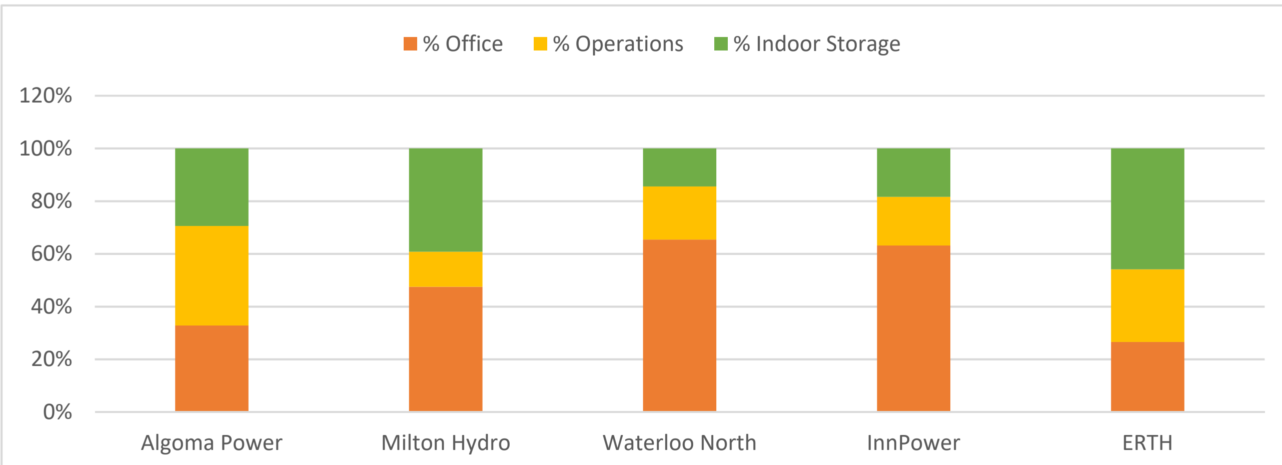
Utility	Case	Acres	Total ft2[8]	OEB Approved CAPEX ($000's)[9]
Algoma Power	EB-2019-0019	7	41,703	$15,361
Milton Hydro	EB-2015-0089	7	91,828	$24,594
Waterloo North	EB-2010-0144	20	104,000	$57,839
InnPower	EB-2014-0086	7	36,172	$19,129
ERTH Power	**EB-2024-0019**	**6**	**50,624**	**$33,439**

One notable characteristics of ERTH Power's New Facility relative to its peers is the designed purpose of the facility. ERTH Power's new building is first and foremost an operational facility required to enable the utility to continue to provide safe and reliable service to an expanded and geographically dispersed customer base.

[8] Excludes ft2 reserved for affiliate or other non-utility use
[9] Inflation adjusted based on a weighted index relying on StatsCan Non-Residential Building Construction Index and StatsCan Value per Acre of Land in Ontario

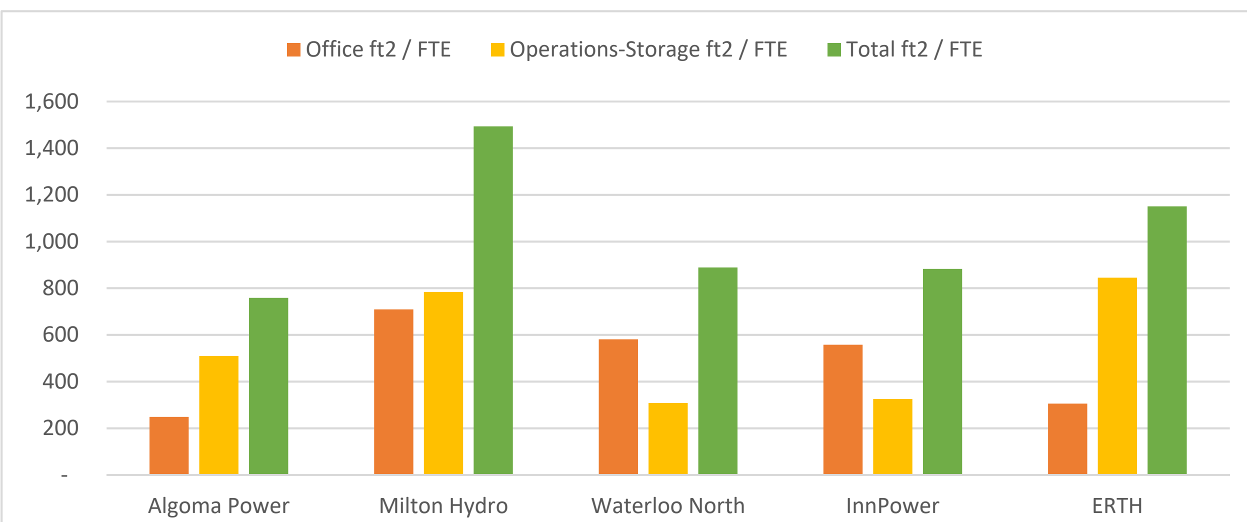
As shown in Figure 8 below, this reality is clearly demonstrated when evaluated against the peer group, with ERTH Power's New Facility having the lowest percentage of Office space relative to the total ft2 of the facility.

Figure 8: Percentage of Space Dedicated to Office, Operations and Indoor Storage



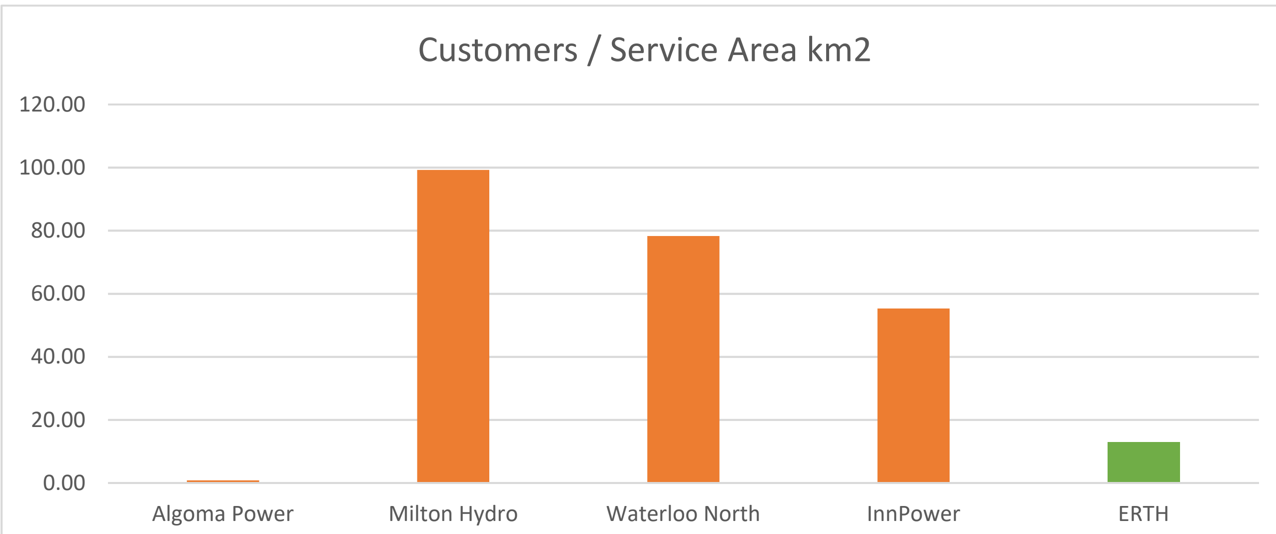
The trend observed above continues when analyzed relative to FTEs planned for the facility in question, with ERTH Power having a very low ratio of Office ft2 to FTE, and higher ft2 to FTE ratios for Operations and Indoor Storage:

Figure 9: Gross Floor Space Dedicated to Office, Operations and Indoor Storage



As demonstrated above, ERTH Power prioritized floor space to operations and indoor storage. One of the principal drivers of this design choice relates to the utility's characteristics as a rural distributor with a dispersed service territory separated by long distances. This can be observed in Figure 1 of this evidence which depicts ERTH's service territory in Southwestern Ontario, but also in the figure below which shows that among the peer group, only Algoma Power has less customers per km^2 of service territory:

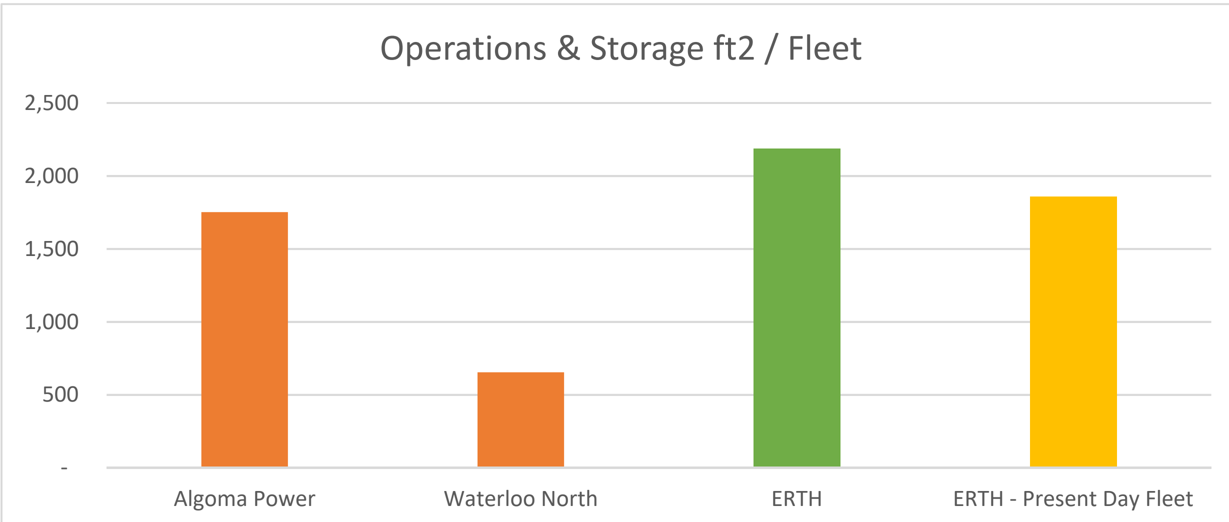
Figure 10: Customers per km2 of Service Area



The reality of operating in a broad, dispersed, rural environment is the need to have a healthy fleet, with a higher proportion of vehicles ready for dispatch in extreme weather events. Unlike some of the suburban distributors included within the peer group, when ERTH Power dispatches a truck there is significant travel time from truck-roll to incident investigation. Naturally, dispatched trucks can only travel to one place at one time, meaning that a widespread incident will require multiple vehicles to simultaneously dispatch in multiple directions.

With the above in mind, there is a relationship between the size of a service territory, the size of a distributor's fleet, and the operational and indoor storage area required. Fleet size during the in-service year of new facilities was not readily available for all members of the peer group, however the figure below shows Operations and Storage ft2 relative to fleet size across a subset of the peer group. This analysis shows that ERTH Power's new building is comparable to Algoma Power's approved facility in this regard, as Algoma is another rural distributor which must dedicate facility space to the storage and staging of fleet vehicles to service a broad and diverse territory in a variety of weather conditions.

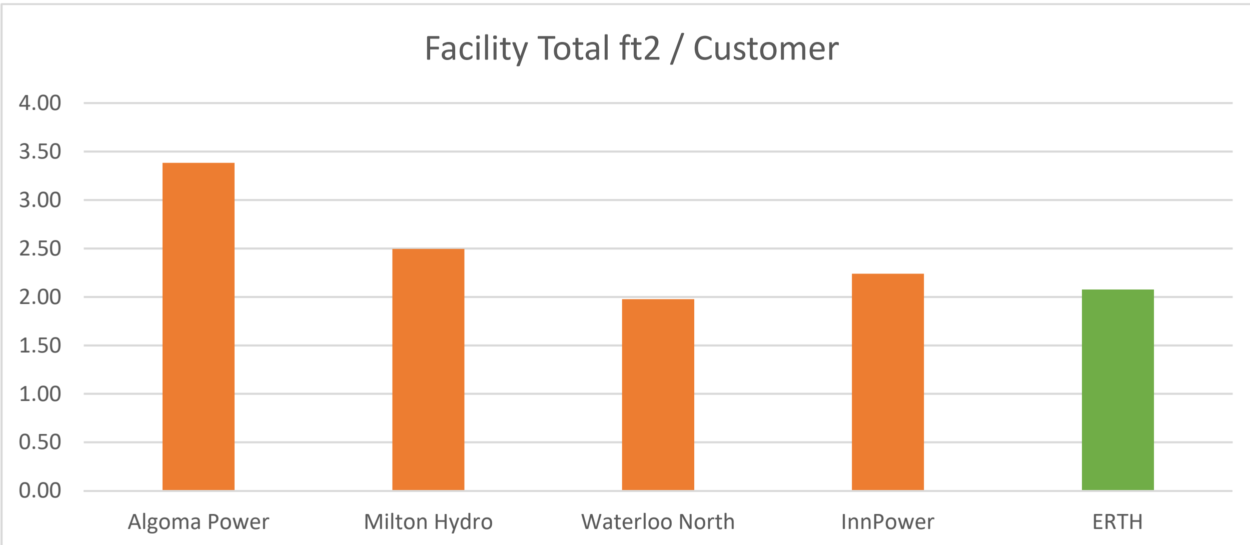
Figure 11: Operations & Storage ft2 relative to Fleet Count[10]



Finally, an additional means to assess the appropriateness of a new distributor building is to compare it to the size of the customer base in question. The figure below shows Total ft2 per Customer for each of the facilities analyzed, and demonstrates that ERTH Power is on the low end of this metric:

[10] ERTH figure assumes ERTH Power is able to reduce fleet by 1 heavy and 2 light vehicles through repatriation of Aylmer facility. ERTH – Present Day Fleet assumes this reduction is not possible or optimal

Figure 12: Facility ft2 relative to Customer Count



The combined analysis above indicates that ERTH Power's New Facility is reasonable and appropriate in its size and composition to service the needs of its territory and customers.

Renewable Building Energy Systems vs Conventional Building Energy Systems

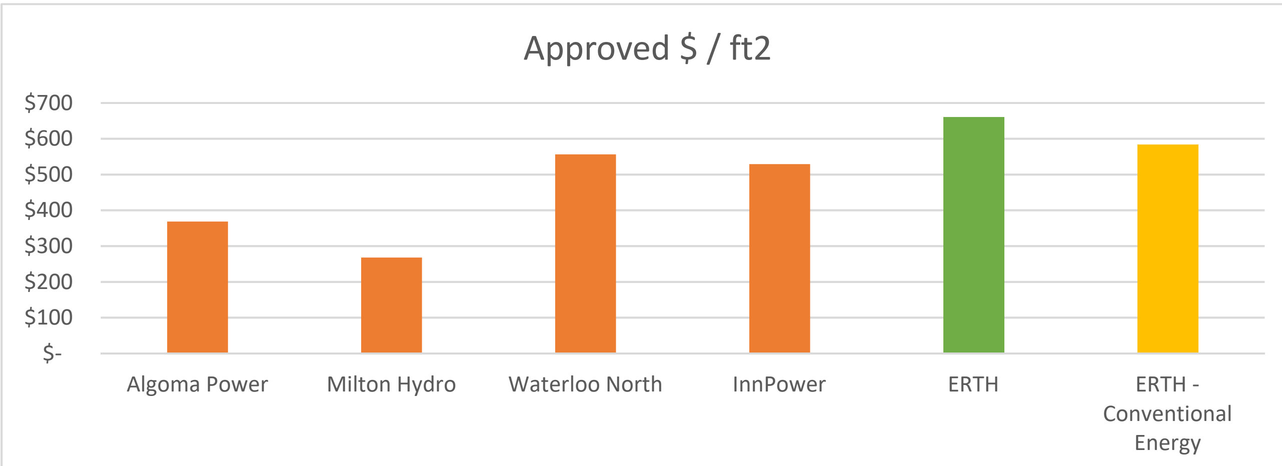
With respect to capital cost, the following analysis of cost per ft2 of facility indicates a cost for ERTH Power's facility that is reasonable relative to the peer group. It should be widely accepted that any New Facility requires a set of energy systems that will provide it both electricity and fuel for space heating. As noted above, ERTH Power has decided to construct its New Facility with decarbonized building energy systems.

For the purpose of comparison, ERTH Power has included an additional data point in its peer group analysis, demonstrating an estimate of the ERTH Power facility in the event it was serviced by conventional energy systems (i.e. natural gas heat and conventional air conditioning, with no solar photovoltaic system).

Figure 12 below shows that the incremental cost of ERTH Power's New Facility being serviced by decarbonized building energy systems results in a cost per ft2 that is reasonable relative to the peer group.

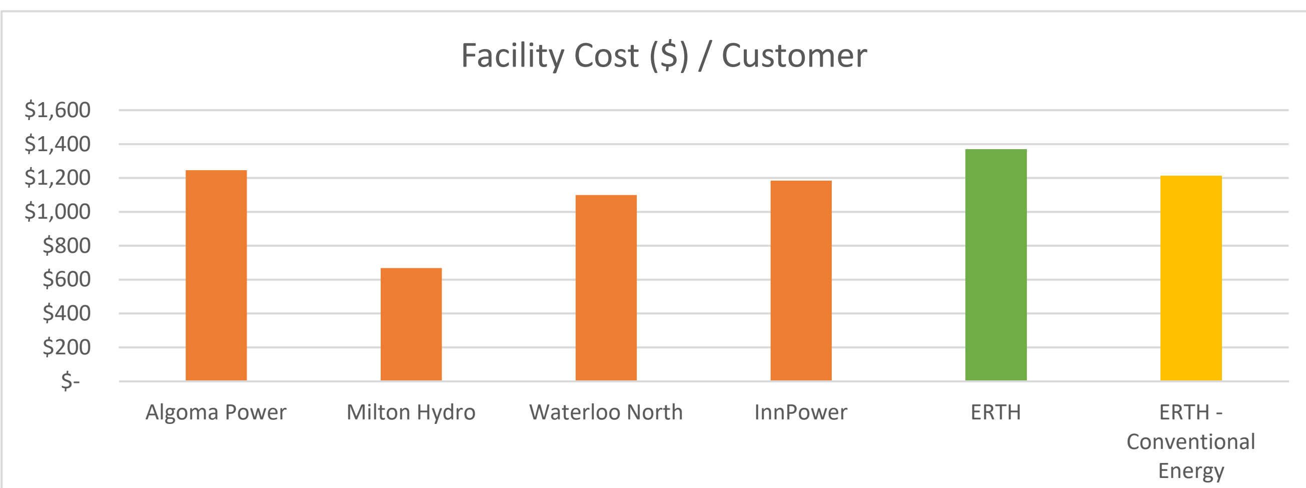
Of note, while ERTH Power has made best efforts to capture the impact of extraordinary inflation costs over the period in which peer utility facilities were constructed, direct and regionally-specific indices for such specific property types were not readily available in the preparation of this analysis. With particular respect to land costs, ERTH Power is of the view the inflation assumptions relied upon may be conservative, and may understate the impact of inflationary increases over the past decade.

Figure 13: OEB-Approved Capital Expenditures relative to Total ft2



Similarly, an analysis of facility cost per customer indicates that when viewed alongside ERTH's customer count, the new ERTH Power building is reasonable amongst the peer group. ERTH Power's progressive decision to install decarbonized building energy systems does not materially impact its benchmarked position relative to its peer group:

Figure 14: OEB-Approved Capital Expenditures relative to Total Number of Customers



What a capital expenditure benchmarking analysis cannot fully capture is the ongoing operational savings of ERTH Power's energy system decisions,[11] in addition to their importance as timely 'no regrets' decisions to facilitate the energy transition during the one-time opportunity of new building construction. The positive financial impacts of these decisions on revenue requirement, through solar and ground-source heat pump operating cost reductions, are reflected in the Options Analysis included within this evidence.

In conclusion, benchmarking against 4 other OEB-regulated, mid-sized distributor facilities, ERTH Power's New Facility appears reasonable and appropriate in its size, composition, and cost.

3.6. Stakeholder Engagement

ERTH Power's stakeholder engagement focused on its nine municipal shareholders as representatives of its customers ("Stakeholder Group"). Members of the Stakeholder Group included elected officials and their staff. The engagement with the Stakeholder Group included their review of the proposed project, and ultimate endorsement and full support for the project. To achieve the endorsement of the Stakeholder Group, ERTH Power incorporated their feedback into the design and procurement processes.

4. Incremental Capital Module Eligibility

The OEB's ICM policy, as set out in the Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, dated September 18, 2014 and the subsequent Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report (collectively referred to as the "ICM Report"), dated January 22, 2016, was established to address the treatment of a distributor's capital investment needs that arise during a Price Cap IR rate-setting plan which are incremental to a calculated materiality threshold.

In order to be eligible for incremental capital, an ICM claim must be incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates; and satisfy the eligibility criteria of materiality, need and prudence, as set out in the ICM Report and shown below:

[11] A complete and accurate benchmarking of revenue requirement / annual costs of the peer group was not possible due to the potential for significant unknowns and variances over time (e.g. site-specific operational costs, changes in tax law)

Criteria	Description
Materiality	A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.
Need	The distributor must pass the Means Test (as defined in the ACM Report). Amounts must be based on discrete projects and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

4.1. Materiality

The ICM Report sets out two materiality tests; the Materiality Threshold and the Project-Specific Materiality Test:

1. **Materiality Threshold**: A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this

ICM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.

2. **Project Specific Materiality Test**: Minor expenditures in comparison to the overall capital budget should be considered ineligible for ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.

4.1.1.Materiality Threshold and Maximum Eligible Incremental Capital

In order to determine the maximum eligible incremental capital which a distributor may seek recovery of in an ICM application, the applicant must first complete calculation of the Board-defined materiality threshold using the following formula:

$$\boldsymbol{Threshold\ Value}\ (\%) = \mathbf{1} + \left[\left(\frac{\boldsymbol{RB}}{\boldsymbol{d}}\right) \times (\boldsymbol{g} + \boldsymbol{PCI} \times (\mathbf{1} + \boldsymbol{g}))\right] \times \left((\mathbf{1} + \boldsymbol{g}) \times (\mathbf{1} + \boldsymbol{PCI})\right)^{\boldsymbol{n}-\mathbf{1}} + \mathbf{10}\%$$

where:

RB = Approved rate base from the distributor’s last CoS application.

d = Approved depreciation expense from the distributor’s last CoS application.

g = Growth is calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a CoS application.

PCI = Price Cap Index (IPI stretch factor) of 3.3%, which in this application is equal to the OEB’s published Inflation Factor for 2025 of 3.6%, minus 0.3%.

n = Number of years since the last rebasing.

ERTH Power has completed the OEB’s most recent ICM Model for each of the Main and Goderich rate zones to determine the materiality thresholds for the 2025 rate year, as shown below:

Table 6: ICM Materiality Thresholds

Rate Zone	Materiality Threshold ($000's)

Main Rate Zone	$4,198
Goderich Rate Zone	$882

Per the ICM Report, the materiality threshold must be compared against the total planned capital expenditures for the year in question. The total planned capital expenditures, less the materiality threshold, equal the maximum eligible incremental capital which may be sought for ICM recovery.

In ERTH Power's case, this calculation must be completed separately for each of the Main and Goderich rate zones. As noted, ERTH Power has completed a DSP for its entire service territory (i.e. the Main and Goderich rate zones) attached to this application, which informs the planned capital expenditures in 2025. The total planned capital expenditures in 2025 are $38.9 million, made up of the $33.4 million cost of the New Facility, and $5.5 million in other capital.

Though ERTH Power operates on an integrated basis, and does not explicitly prepare and execute capital plans for its two rate zones separately, the total planned 2025 capital expenditures must be allocated to the Main and Goderich rate zones in order to determine maximum eligible incremental capital. To complete this allocation, ERTH Power determined the proportion of capital expenditures in each rate zone relative to its total capital expenditures on an actual basis over the 2018 to 2023 period. The average of these six years of actuals indicates an allocation of 81% to the Main rate zone, and 19% to the Goderich rate zone. Based on the application of this historical average to 2025 capital expenditures, the planned 2025 capital expenditures for the Main and Goderich rate zones are $31.7 million and $7.3 million, respectively.

Utilizing the figures above, ERTH Power has calculated the maximum eligible incremental capital for each rate zone, and determined that 100% of the New Facility is eligible for incremental funding in accordance with the materiality threshold test, as demonstrated below:

Table 7: Maximum Eligible Incremental Capital

Component	**($000's)**
Main Rate Zone	
Capital Expenditures	$31,652
Materiality Threshold	$4,198
Maximum Eligible Incremental Capital	$27,454
Goderich Rate Zone	
Capital Expenditures	$7,271
Materiality Threshold	$882
Maximum Eligible Incremental Capital	$6,389
Total Maximum Eligible Incremental Capital	**$33,844**
New Facility Capital Cost	$33,439
Eligibility of New Facility for ICM Funding (%)	100%

4.1.2.Project Specific Materiality

At a capital cost of $33.4 million, the New Facility represents a one-time expenditure that is 5.8 times all other capital expenditures planned for 2025, and 7.6 times ERTH Power's average actual capital expenditures over the 2018 to 2023 period. ERTH Power submits that the New Facility is clearly not a minor expenditure as referenced in the ICM Report. Further, as described in section 3 above, the New Facility is an important and foundational investment, that will have a significant influence on the operations of the utility now and in the future.

ERTH Power submits that the New Facility passes the project specific materiality test.

4.2. Need

In order to qualify for ICM funding, a distributor must demonstrate that there is a need for the incremental funding. The ICM Report requires a three-fold test to demonstrate need:

1. The distributor must pass the Means Test.
2. Amounts must be based on discrete projects and should be directly related to the claimed driver.
3. The amounts must be clearly outside of the base upon which rates were derived.

4.2.1.Means Test

If a distributor's most recently available regulated return on equity ("ROE") exceeds 300 basis points above the deemed ROE embedded in the distributor's rates, then funding for any incremental capital project would not be allowed. In ERTH Power's case, the appropriate value for comparison is a blended deemed ROE between the Main and Goderich rate zones, weighted on the basis of average actual capital expenditures over the 2018 to 2023 period. On this basis, the follow table presents ERTH Power's completion of the Means Test:

Table 8: Means Test

Component	%
Actual 2023 ROE	9.32%
Deemed ROE	9.02%
Difference	**0.30%**

ERTH Power meets the OEB's Means Test for ICM eligibility.

4.2.2.Discrete Project Unfunded through Rates

As described in section 3 above, the New Facility is a discrete project which is not part of any ongoing capital program, and is not funded through rates. Given the investment's significant, one-time, and foundational nature for the utility, ERTH Power submits it passes parts 2 and 3 of the OEB's Need Test for ICM eligibility.

4.3. Prudence

To satisfy the criteria of prudence, a distributor needs to establish that the incremental capital amount it proposes to incur is prudent. To satisfy the "prudence test", a distributor must demonstrate that its decision to incur the incremental capital represents the most cost-effective option for its customers (though, not necessarily the least cost option).

As further described in section 3.4 above, ERTH Power completed an Options Analysis to meet its facility needs, and has concluded that the construction of a new administrative and operational centre represents the most cost-effective option for ratepayers. To further assess the prudence of its investment, ERTH Power has also completed and provided a benchmarking analysis in section 3.5, demonstrating the reasonableness of its New Facility design and expenditure relative to a group of relevant peer utilities.

With respect to land procurement, ERTH Power completed a diligent search for the most appropriate and cost effective land acquisition available, based on the specifications provided in Table 1. Similarly, ERTH Power engaged Powell Engineering to prepare a purpose-built building design to meet its explicit needs for administrative staff, control centre and server operations, emergency response, fleet maintenance and storage, materials storage, and future growth, among other specifications. ERTH Power submits that the building design is functional, and appropriate for the current needs of ERTH Power, with reasonable accommodation for growth as the utility's needs evolve in the coming years.

For the purpose of construction procurement, ERTH Power conducted a competitive tendering process with the expert assistance of JPM Architecture Inc. ("JPM"). Of the total 7 suitable contractors invited to bid on the construction of the New Facility, 5 submitted bids into the competitive process. At the time of submitting this application, ERTH Power is in the process of reviewing the submitted bids and selecting a successful proponent, with the assistance and expertise of JPM. Based on ERTH Power's initial assessment, all 5 bids are compliant with the requirements specified in the tendering process, and the utility is confident 1 of the 5 potential contractors will prove to be suitable for construction of the New Facility, and will do so at a cost that is reasonable and representative of prudent expenditure.

ERTH Power submits that it has passed the OEB's Prudence Test for the purpose of ICM eligibility.

5. ICM Financial Implications

5.1. Half-Year Rule, Capital Cost Allowance and PILs

The Half-Year Rule is not applicable in this case as the New Facility in-service year (2025) does not coincide with the final year of ERTH Power's IRM term (2027).

ERTH Power notes that it has not reflected the recent changes to Capital Cost Allowance tax rules, resulting from Bill C-97, in its ICM calculations. Consistent with the OEB's letter of July 25, 2019, ERTH Power intends to book any impacts of the CCA rule changes in account 1592-PILS and Tax Variances for this and all other affected capital additions.

The above said, ERTH Power has elected to take a reduced CCA on the mechanical and energy systems portion of its New Facility. In reducing the amount of CCA claimed in this ICM application, and over the course of the 2025, 2026 and 2027 tax years, a higher Undepreciated Capital Cost ("UCC") balance will remain at ERTH Power's 2028 CoS, which will all else equal increase CCA at that time, reduce taxable income, and reduce PILs in rates for customers. In total, ERTH Power has reduced its planned full year CCA claim by $413,129 relative to the maximum CCA available. The impact of this choice within the ICM construct is annual PILs of $0 for both the Main and Goderich rate zones.

5.2. Derivation of ICM Rate Riders

ERTH Power is seeking OEB approval of the ICM rate riders identified in this section to recover the incremental capital-related revenue requirement of the New Facility. The following table depicts the incremental revenue requirement, as calculated in the Main and Goderich rate zone ICM models attached to this application:

Table 9: Incremental Revenue Requirement

Component	Main RZ ($000's)	Goderich RZ ($000's)	Total ($000's)
Return on Rate Base	$1,618	$383	$2,001
Amortization Expense	$632	$145	$777
Gross Up Taxes/PILs	$0	$0	$0
Total	**$2,250**	**$528**	**$2,778**

ERTH Power has completed the OEB's ICM model for both the Main and Goderich rate zones, relying on data from each rate zone's most recent CoS, 2023 billing determinants, 2023 current rates, and details of the New Facility's costs as inputs. The completed ICM models for the Main and Goderich rate zones have been provided as Appendix C and Appendix D, respectively. The resulting ICM rate riders for each rate zone are presented in the tables below:

Table 10: ICM Rate Riders – ERTH Main Rate Zone

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$1,432,854	18,542	152,664,526		6.44		
GENERAL SERVICE LESS THAN 50 kW	$254,565	1,907	51,446,504		4.59	0.0029	
GENERAL SERVICE 50 TO 999 kW	$178,430	126	75,757,113	226,206	25.55		0.618
GENERAL SERVICE 1,000 TO 4,999 kW	$128,283	11	85,815,177	184,771	524.51		0.3196
LARGE USE	$107,672	2	83,731,041	145,618	2142.21		0.3863
UNMETERED SCATTERED LOAD	$6,531	91	388,739		0.44	0.0156	
SENTINEL LIGHTING	$16,530	380	201,111		2.75	0.0199	
STREET LIGHTING	$83,847	6,426	2,010,730	5,454	0.77		4.4808
EMBEDDED DISTRIBUTOR	$41,576	4	19,160,929	41,284	349.32		0.6009
Total	**$2,250,288**	**27,489**	**471,175,870**	**603,333**			

Table 11: ICM Rate Riders – ERTH Goderich Rate Zone

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$275,034	3,453	25,854,642		6.64		
GENERAL SERVICE LESS THAN 50 kW	$67,736	487	13,497,798		6.45	0.0022	
GENERAL SERVICE 50 TO 999 kW	$36,152	36	17,563,414	47,225	30.89		0.4829
GENERAL SERVICE 500 TO 4,999 kW	$38,061	6	25,982,761	64,341	327.67		0.2249
LARGE USE	$88,496	1	71,328,793	182,747	1971.04		0.3548
SENTINEL LIGHTING	$177	2	1,901	5	7.39		
STREET LIGHTING	$20,735	1,467	453,022	984	0.90		4.9472
UNMETERED SCATTERED LOAD	$1,653	3	83,100		15.08	0.0134	
Total	**$528,045**	**5,455**	**154,765,431**	**295,302**			

ERTH Power proposes the ICM rate riders above be made effective May 1, 2025, and continue in rates through to ERTH Power's next re-basing, planned for 2028 rates.

5.3. Deferral and Variance Accounts

ERTH Power requests Board approval to record amounts relating to the New Facility in the applicable 1508 sub-accounts pertaining to ICM projects, with the intention of truing up the balance in its next cost of service application. ERTH Power will follow the accounting treatment for deferral and variance accounts as described in the Accounting Procedures Handbook and the ICM Report

5.4. Bill Impacts

The incremental bill impacts of the ICM rate riders (i.e. ICM bill impacts exclusive of any other component of ERTH Power's 2025 IRM application) for each of ERTH Power's rate zones are presented below:

Table 12: Main Rate Zone Bill Impacts

ICM Rate Rider Bill Impacts	Distribution Bill	Total Bill	ICM Rider Revenue	Distribution Impact	Total Impact
RESIDENTIAL	37.56	137.81	6.44	17.15%	4.67%
GENERAL SERVICE LESS THAN 50 kW	60.60	327.82	10.39	17.15%	3.17%
GENERAL SERVICE 50 TO 999 kW	509.49	10,354.60	87.35	17.14%	0.84%
GENERAL SERVICE 1,000 TO 4,999 kW	5,389.11	129,750.26	924.01	17.15%	0.71%
LARGE USE	40,324.06	589,710.15	6913.02	17.14%	1.17%
UNMETERED SCATTERED LOAD	16.18	42.57	2.78	17.18%	6.53%
SENTINEL LIGHTING	25.31	41.68	2.75	10.87%	6.60%
STREET LIGHTING	30.62	132.94	5.25	17.15%	3.95%
EMBEDDED DISTRIBUTOR	4,350.76	17,516.66	745.91	17.14%	4.26%

Table 13: Goderich Rate Zone Bill Impacts

ICM Rate Rider Bill Impacts	Distribution Bill	Total Bill	ICM Rider Revenue	Distribution Impact	Total Impact
RESIDENTIAL	39.71	135.92	6.64	16.72%	4.89%
GENERAL SERVICE LESS THAN 50 kW	65.16	319.68	10.85	16.65%	3.39%
GENERAL SERVICE 50 TO 999 kW	545.95	10,701.87	91.25	16.71%	0.85%
GENERAL SERVICE 500 TO 4,999 kW	4,247.25	134,363.26	710.00	16.72%	0.53%
LARGE USE	43,632.05	705,773.90	7293.04	16.71%	1.03%
SENTINEL LIGHTING	44.21	3,996.40	7.39	16.72%	0.18%
STREET LIGHTING	19,450.16	25,325.98	3251.21	16.72%	12.84%
UNMETERED SCATTERED LOAD	98.21	126.37	16.42	16.72%	12.99%

ERTH POWER

ERTH Power Corporation

Distribution System Plan

2024-2029

This document details ERTH Power Corporation's Asset Management Process and Capital Expenditure Plan as required by the OEB filing requirements set out in the 'Chapter 5 Consolidated Distribution System Plan Filing Requirements'.

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List of Acronyms

LDC	Local Distribution Company
RIP	Regional Infrastructure Plan
HONI	Hydro One Networks Incorporated
IRRP	Integrated Regional Resource Plan
IESO	Independent Electricity System Operator
OEB	Ontario Energy Board
DSP	Distribution System Plan (per Chapter 5 Filing Requirements of OEB)
EPC	ERTH Power Corporation
AMI	Advanced Metering Infrastructure
ADMS	Advanced Distribution Management System
DER	Distribute Energy Resource
GIS	Geographic Information System
ICM	Incremental Capital Module
CHEC	Cornerstone Hydro Electric Concepts
UCC	Utility Coordination Committee
ISOG TSOG	Integrated System Operating - Transmission System Outage Groupings
CDM	Conservation Demand Management
REG	Renewal Energy Generator
DCA	Distribution Connection Assessment
CSA	formerly Canadian Standards Association
CIA	Connection Impact Assessment
TS	Transformer Station
KPI	Key Performance Indicator
SAIDI	System Average Incident Duration Index
SAIFI	System Average Incident Frequency Index
CAIDI	Customer Average Incident Duration Index
LoS	Loss of Supply
MED	Major Event Days

5.2 Introduction

This Distribution System Plan (DSP) is submitted by ERTH Power Corporation in accordance with the Ontario Energy Board's (OEB) Filing Requirements for Distribution System Plans, as outlined in Chapter 5 of the 2023 edition for 2024 rate applications and follows the section-structure of that document. The DSP outlines ERTH Power's strategic approach to maintaining and enhancing the reliability, efficiency, and sustainability of its distribution network over a ten-year period, comprising five historical years and five forecast years. This document consolidates the asset management process and capital expenditure plan, reflecting the utility's commitment to providing high-quality service to its customers while meeting regulatory requirements and supporting community growth.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

5.2.1.1 Description of the Utility Company

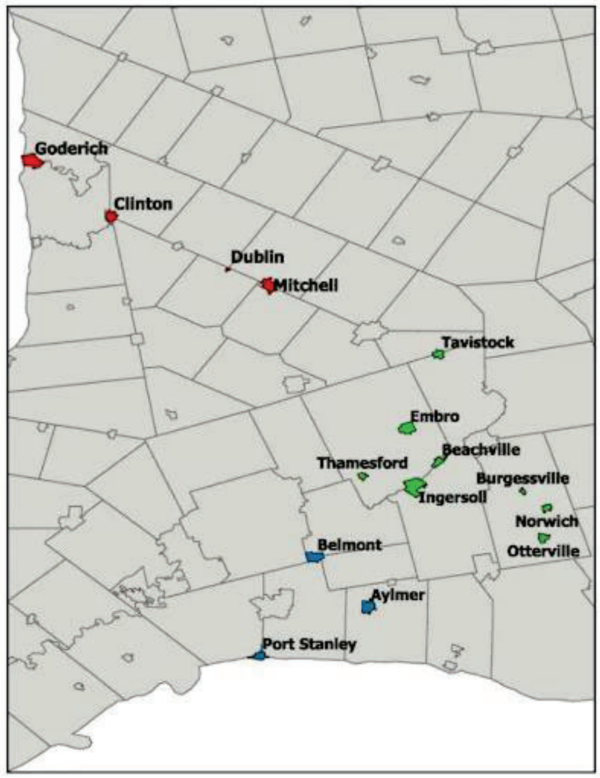
ERTH Power Corporation (EPC) is a local distribution company operating in Southwestern Ontario. It represents the amalgamation of 10 public Utilities Commissions and services, approximately 25,000 customers across four regions: Aylmer, Goderich, Ingersoll and West Perth. in the following fifteen (15) municipalities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Mitchell, Dublin, Clinton & Goderich as shown in ***Table 1.***

Table 1: Service Regions/Ops Centers

Operations Center	Municipalities
Aylmer	Alymer, Port Stanley, Belmont,
Goderich	Goderich, Mitchell, Dublin, Clinton
Ingersoll	Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock

ERTH Power's service territory spans north to south a distance of approximately 130km and all municipalities are embedded within Hydro One service territory. ERTH Power maintains three (3) operations centers located in Aylmer, Goderich and Ingersoll with the later retaining all executive, administration, finance, customer service, metering and engineering departments. ***Figure 1*** below illustrates the ERTH Power service territory along with operations centers and approximate travel times.

Figure 1: Service Territory



ERTH Power is proud to be “Your Hometown Utility” and is guided by our Mission, Vision and Values.

Our Mission

A community partner committed to delivering safe and reliable electricity while providing innovative and high-quality services and solutions to our customers

Our Vision

Working co-operatively as a trusted, quality services and solutions provider, creating value for all stakeholders.

Our Values

Safety First – Promote the importance of health, safety and wellness	
Customer Focus – Remain a leader in customer care and service delivery	
Excellence – Strive for operation and performance excellence	
Innovation – Continuous improvement of people, processes and technology	
Sustainability – Protect the environment and meet the needs of present without compromising future generations	
Committed – Continue long-term commitment to employees and community partnerships	

ERTH Power's mission is to be a community partner committed to delivering safe and reliable electricity while providing innovative and high-quality services and solutions to our customers within the required regulatory framework. With this mission in mind, the DSP aims to achieve the following objectives, which are embedded within our asset management plan and investment optimization process:

- **Maintain Public and Employee Safety;** invest in System Renewal projects to ensure assets are maintain in good, safe condition, invest in General Plant with employee safety in mind ensuring that the proper fleet, tools and equipment are available to safely construct, operate and maintain the distribution system
- **Maintain or Improve Reliability**; System Renewal projects aim to replace end-of-life assets prior to failure, in addition System Renewal projects improve the resiliency of the distribution system for adverse weather events. System Service investments in new technologies/capabilities, automation and SCADA systems improve reliability allowing staff to respond to events more quickly and minimize customer disruptions.
- **Manage Financial Impacts to Customers;** an important function of the DSP is to ensure investments are evaluated and paced in a way to avoid sudden, drastic financial impacts to customers.
- **Meet Mandated Service Obligations;** includes spending on new Residential, Commercial, Industrial & DER connections, within the System Access category. In addition, Meter Management comprises a substantial portion of the capital investment plan ensuring meters are operating properly and meeting regulated requirements.
- **Meet Customer Expectations;** informed by engagement activities and aimed at providing safe, reliable electricity supply, and providing our customers effective communication and tools to engage with ERTH Power.
- **Improve Operational Efficiency;** System Renewal, General Plant & System Service investments are chosen to improve operational efficiency contributing to improved financial performance and reliability.

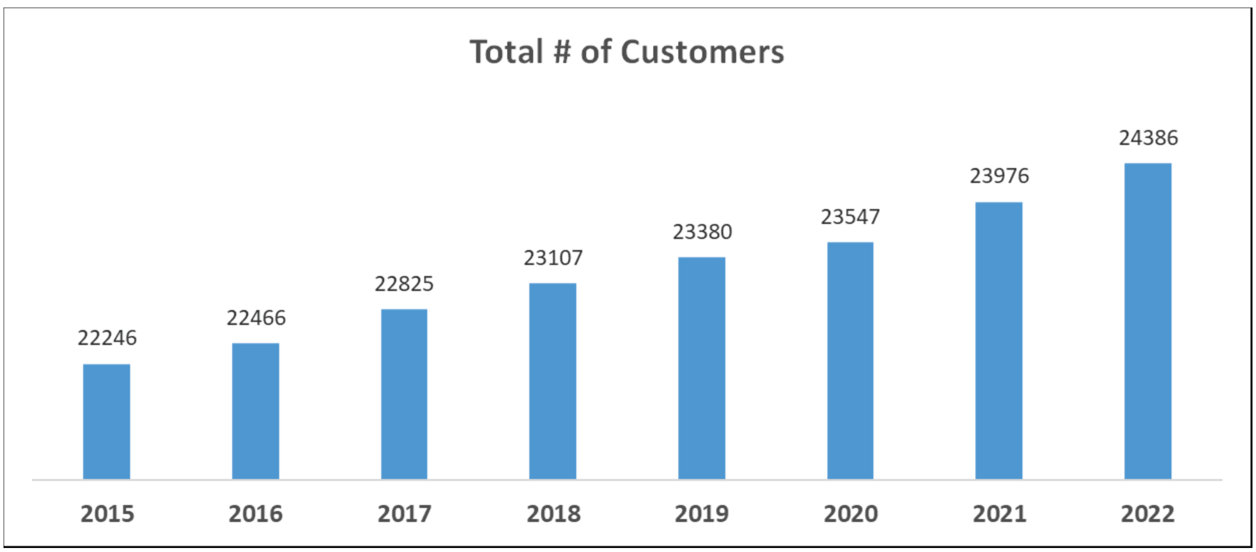
Customer Profile

ERTH Power communities are supplied from nine (9) Hydro One owned and operated transformer stations (TS) at 27.6kV along with four (4) Hydro One owned and operated distribution stations (DS) at 8.32kV. Two ERTH Power communities are considered transmission connected (Aylmer, Goderich) and the remainder are embedded within Hydro One distribution. In addition, ERTH Power operates ten (10) municipal substations (MS) supplying customers at 4.16kV. As a result, of this diverse supply, ERTH Power is connected through twenty-five (25) wholesale-metered supply points.

Due to our unique geography, each ERTH Power community has a distinct supply configuration with both advantages & disadvantages. ERTH Power serves low-density urban communities with residential, commercial and industrial customers throughout our service territory. Our customer base includes three (3) large users spread between operations center, including a GM Assembly Plant in Ingersoll, the Compass Minerals Salt Mine in Goderich and IGPC Ethanol Inc. in Aylmer.

ERTH Power has experienced modest but consistent growth over the past seven years. Our customer base has grown from 22,246 in 2015 to 24,386 in 2022. This is an average yearly growth of 1.32% and 306 customers. See ***Figure 2*** below for customer for customer growth between 2015 and 2022 (including WCHE customer counts).

Figure 2: Customer Growth



The customer base comprises residential, commercial, and industrial segments, each with distinct energy requirements and service expectations. The breakdown of customer count by class is show in ***Table 2*** ERTH Power's mission is to deliver reliable and efficient electrical services through continuous infrastructure maintenance, upgrades, and leveraging modern technologies. The utility prioritizes safety, sustainability, and innovation, ensuring a continuous supply of electricity while supporting the growth and development of the communities it serves.

Table 2: Customer Classes

	2022
General Service < 50 kW	2382
General Service >= 50 kW	177
Large User	3
Residential	21824
Total # of Customers	24386

5.2.1.2 Capital Investment Highlights

Over the next five years, ERTH Power plans several key capital investments to enhance the reliability and efficiency of its distribution system. These investments are detailed below:

- **Substation Refurbishments:** This involves upgrading critical substation components such as transformers, switchgear, and protection systems to improve reliability and extend the service life of substations. These refurbishments will enhance operational efficiency and resilience, addressing both current performance issues and future demand growth.
- **Voltage Conversion:** These projects involve upgrading or modifying the infrastructure to operate at a higher or more efficient voltage level. These projects typically include replacing transformers, upgrading distribution lines, and adjusting equipment to handle increased voltage. The goal is to improve system reliability, reduce energy losses, and increase capacity for future growth. By converting to higher voltages, the system can deliver power more efficiently over longer distances, ultimately enhancing service quality for customers. Voltage conversion efforts will ultimately lead to ERTH Power decommissioning all of our 4kV substations, avoiding costly replacement costs.
- **Smart Grid Technology Implementation:** ERTH Power plans to deploy advanced metering infrastructure (AMI), automated switching capabilities and other smart grid technologies. These investments will enable real-time monitoring and control of the distribution network, improving operational efficiency, reducing outage times, and facilitating the integration of distributed energy resources (DERs). The smart grid technologies will also support advanced data analytics and customer engagement initiatives.
- **Infrastructure Expansion Projects:** To support new residential, commercial, and industrial developments, ERTH Power will expand the distribution network to accommodate increased demand. This includes constructing new feeder lines, upgrading existing circuits, and installing new distribution transformers. These projects are critical to ensuring that the infrastructure can meet future load growth and provide reliable service to new customers.

ERTH Power follows the OEB specified investment categories to be used by distributors in rate filings.

Table 3: Summary of Investment Drivers

Investment Category	OEB Example Drivers
System Access	Customer Service Requests Other 3rd Party Infrastructure Mandated Service Obligations
System Renewal	Assets and asset systems at end of service life due to: • Failure • Failure Risk (ACA) • Substandard Performance • High performance Risk • Functional Obsolescence
System Service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery System Operational Objectives: • Safety • Reliability • Power Quality • System Efficiency • Other Performance/Functionality
General Plant	System Capital Investment Support System Maintenance Support Business Operations Efficiency Non-System Physical Plan

The Capital Plan is detailed in Section 5.4 with summary level in ***Table 4*** below.

Table 4: Summary of Capital Plan

	Forecast Capital Expenditures					
	Bridge	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
CATEGORY	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
System Access	$651,750	$1,061,876	$1,083,114	$2,229,776	$2,246,652	$2,269,085
System Renewal	$2,892,000	$3,186,162	$3,266,704	$3,397,316	$3,578,000	$3,758,758
System Service	$34,800	$120,000	$122,400	$124,848	$127,345	$129,892
General Plant	$1,148,201	$1,115,729	$1,708,201	$1,035,581	$898,067	$1,127,330
TOTAL	**$4,726,751**	**$5,483,767**	**$6,180,419**	**$6,787,521**	**$6,850,064**	**$7,285,065**

5.2.1.3 Key Changes since Last DSP Filing

Since the last DSP filing, ERTH Power has implemented several significant enhancements to its asset management processes and infrastructure planning. These key changes are as follows:

- **Enhanced GIS Capabilities:** Upgrades to geographic information systems (GIS) have improved spatial data management and asset tracking. These enhancements provide more accurate and up-to-date information for planning and operational decisions, supporting efficient infrastructure management and investment planning.
- **Expanded Stakeholder Engagement:** ERTH Power has increased efforts in stakeholder engagement, leading to better incorporation of customer feedback into planning decisions. Regular consultations with large customers, municipalities, and developers have helped align infrastructure investments with community needs and customer expectations.
- **Adoption of Advanced Asset Management Practices:** The utility has implemented refined asset management practices and tools, including updated asset condition assessment methodologies and lifecycle management strategies. These practices have improved the prioritization and optimization of capital investments, ensuring that resources are allocated efficiently to meet system and customer needs.

5.2.1.4 DSP Objectives

The primary objectives of this DSP are as follows:

- **Ensuring Safety and Reliability**: ERTH Power aims to maintain and enhance the safety and reliability of the distribution system through strategic investments and operational improvements. This includes upgrading aging infrastructure, implementing advanced protection systems, and enhancing grid resilience against environmental and operational risks.
- **Optimizing Cost-Effectiveness**: The utility seeks to balance capital and operational expenditures to deliver cost-effective solutions while maintaining high service standards. This objective is achieved through efficient planning, prioritization of critical projects, and leveraging technology to optimize operations.
- **Supporting Renewable Integration**: ERTH Power is committed to facilitating the integration of distributed energy resources (DERs) and renewable energy sources. This includes investments in

grid modernization to accommodate renewable energy connections and implementing advanced grid management systems to handle the variability of renewable generation.

- **Enhancing Customer Satisfaction**: Improving customer service and engagement is a key objective. ERTH Power plans to achieve this through responsive service and infrastructure investments that meet customer needs. Initiatives include expanding customer communication channels, improving outage management and response times, and implementing programs to enhance customer awareness and participation in energy conservation initiatives.

The overall objective of this DSP is to rationalize spending between the legacy ERTH territory and the new Goderich (WCHE) territory into a harmonized plan. There is a general increase in Capital Spending to accommodate the connections of new customers and increase investment in System Renewal as is indicated by the Asset Condition Assessment in Section 5.3.

If a distributor is aware of a potential future ICM request but has chosen not to apply for the Advanced Capital Module (e.g. due to uncertainty of whether the project will proceed or a lack of complete information to fully support the request in the DSP), the distributor should still identify the project and provide commentary around the potential future ICM request.

This DSP supports the ICM application for building a new operations center for ERTH Power. It does not focus on the operations center as a separate project, as that is covered by the ICM application. Instead, the DSP outlines and justifies all other projects planned for the 2025-2029 forecast period, with the operations center's costs being in addition to the DSP's projected expenditures.

5.2.2 COORDINATED PLANNING WITH THIRD PARTIES

5.2.2.1 Customers

ERTH Power conducts regular consultations with large customers and subdivision developers to understand their future energy requirements and integrate these needs into the DSP. These engagements ensure that infrastructure investments align with customer demands and support efficient and reliable service delivery. Customer feedback is collected through surveys, focus groups, and direct consultations, which are then analyzed and incorporated into the planning process to address specific needs and expectations.

ERTH Power regularly surveys this customer base to get an understanding of the issues facing the customers and the impressions the customers have of the value received. The most recent survey was executed by ADVANIS in March 2023. The following tables and graphics are some of the key outputs extracted from the survey report. The entire survey is attached in ***Appendix A***.

Customers Surveyed

The survey was split the across 15 service areas of ERTH Power (Mitchell and Dublin are combined in "West Perth"). The process surveyed 403 customers or approximately 1.84% of the base. The mix of customers surveyed is approximately 93% Residential and 7% General Service <50 kW as shown in ***Table 5*** below.

Table 5: Customer Survey Responses

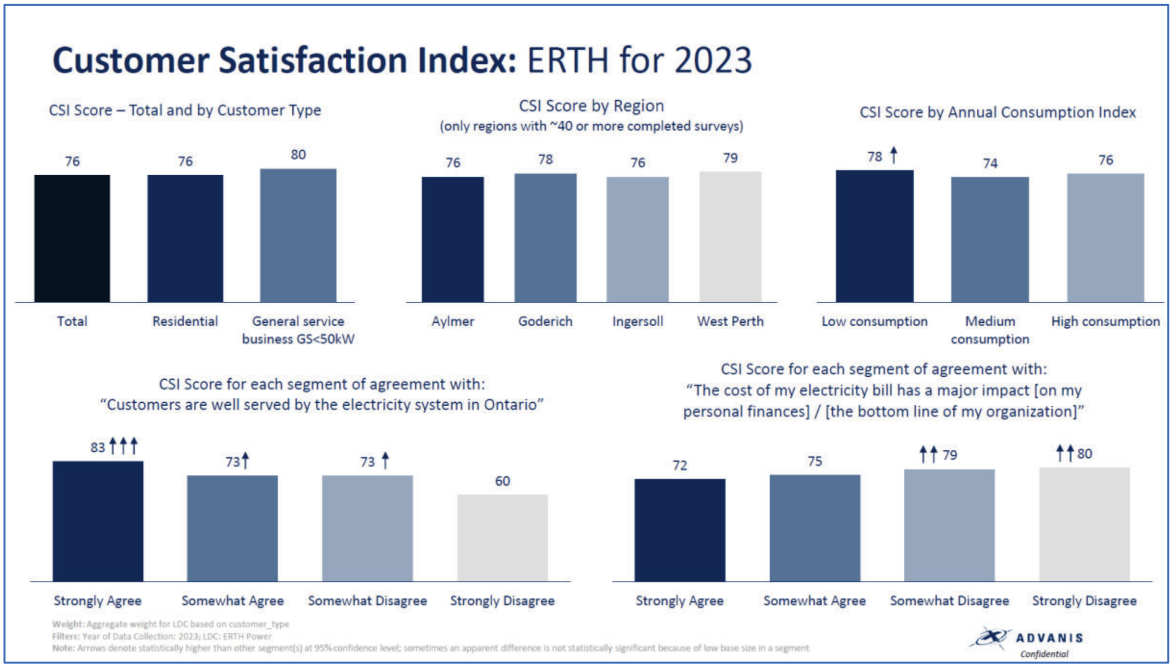
Region - information provided by ERTH Power	2019	2021	2023
Aylmer	16%	13%	13%
Beachville	2%	2%	2%
Belmont	4%	4%	4%
Burgessville	1%	1%	1%
Clinton	9%	7%	7%
Embro	2%	2%	2%
Goderich [2021 onwards; added in 2019 but after Csat]		17%	16%
Ingersoll	28%	24%	23%
Norwich	7%	6%	6%
Otterville	2%	2%	2%
Port Stanley	8%	7%	7%
Tavistock	7%	6%	6%
Thamesford	3%	3%	3%
West Perth	11%	9%	10%
Base	402	401	403

Customer Satisfaction

One of the important questions in the survey is a test of general “Customer Satisfaction” compared by “type of customer”, “region” and “consumption” and in each case the score was consistent which indicates that satisfaction does not vary for different users of the ERTH Power system. (See).

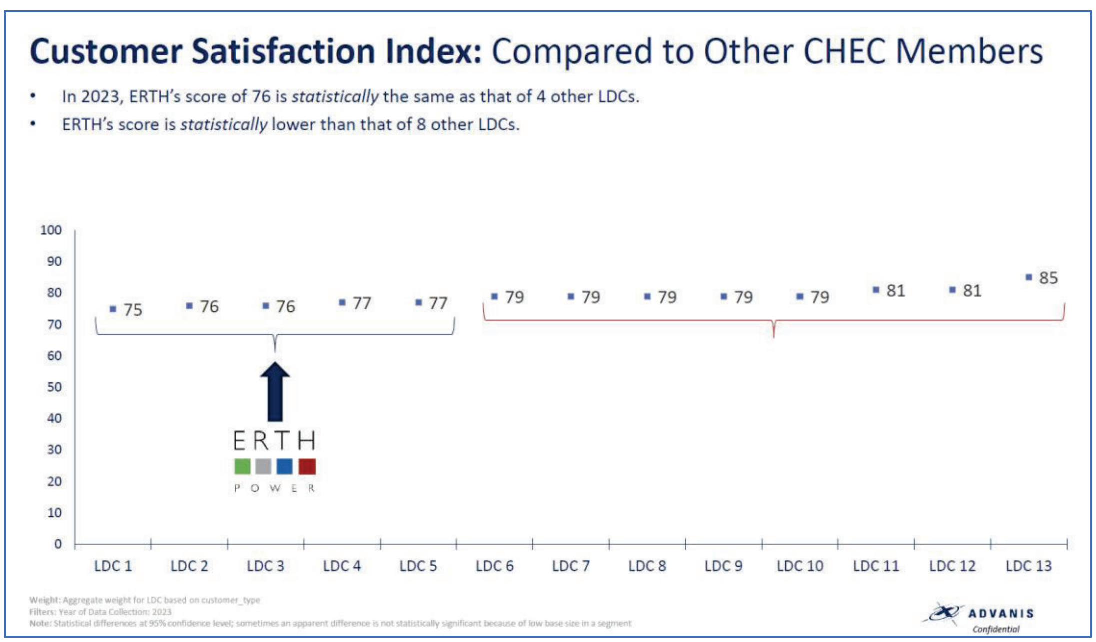
Customers also indicated that they feel generally we served by the electricity system in Ontario, but also that the cost of electricity is a significant impact on their personal or business finances. (See).

Figure 3: Customer Satisfaction Index across Users



ERTH Power is a member of the CHEC group, (a group of 13 peer LDC's in Ontario) and is able to compare the results of the Customer Satisfaction survey with other members. ERTH Power is statistically the same as 4 other LDC's and nominally below the remaining 8. (***Figure 4***).

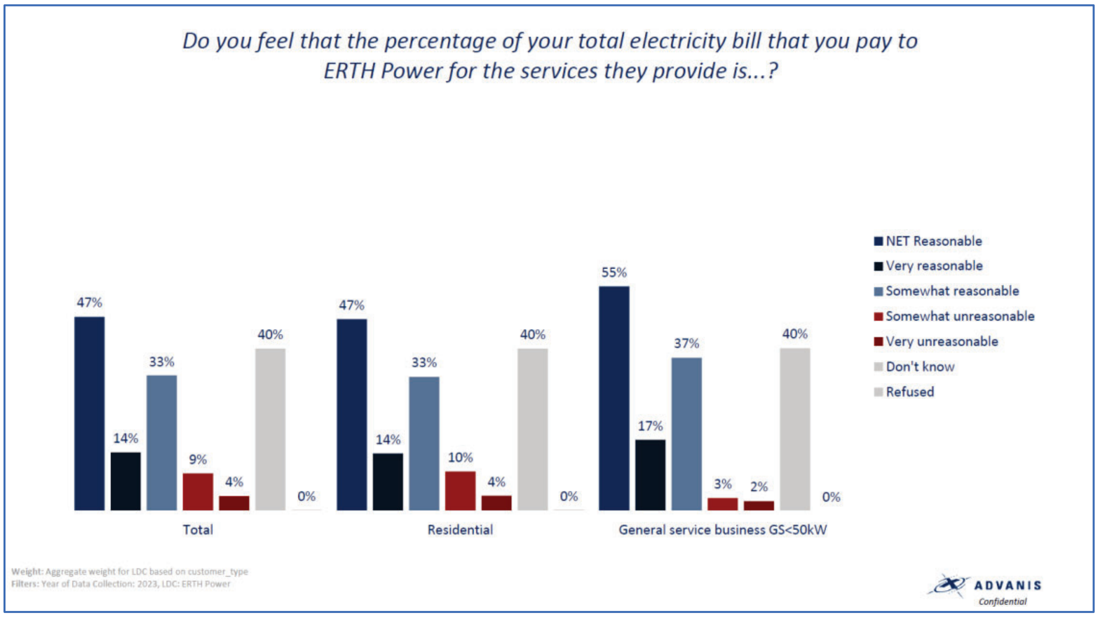
Figure 4: Customer Satisfaction Compared to CHEC Group



Reasonableness of ERTH Power Component of Bill

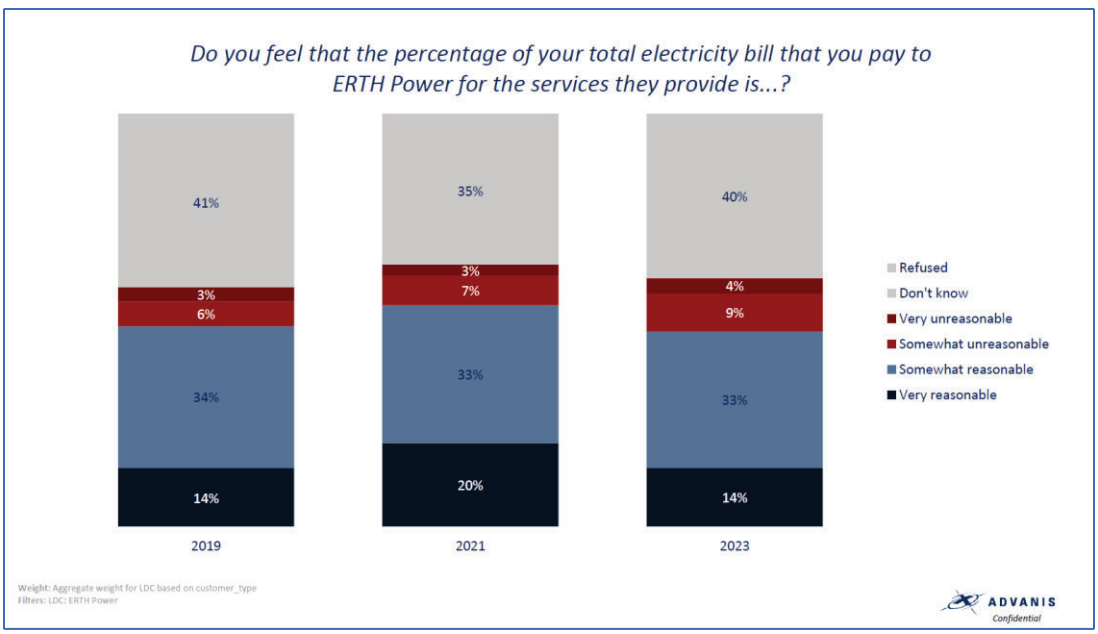
Customers were asked if the ERTH Power portion of their bills were reasonable for the services that ERTH Power provides and approximately half of all customers responded with either “very reasonable” or “somewhat reasonable” with about 40% responded that they didn’t know. (See ***Figure 5***).

Figure 5: Reasonableness of ERTH Power Costs and Services



The same question has been asked in previous surveys and a comparison of the results reveals that the customer's impression of the reasonableness of the ERTH Power services has been constant since 2019. (See ***Figure 6***).

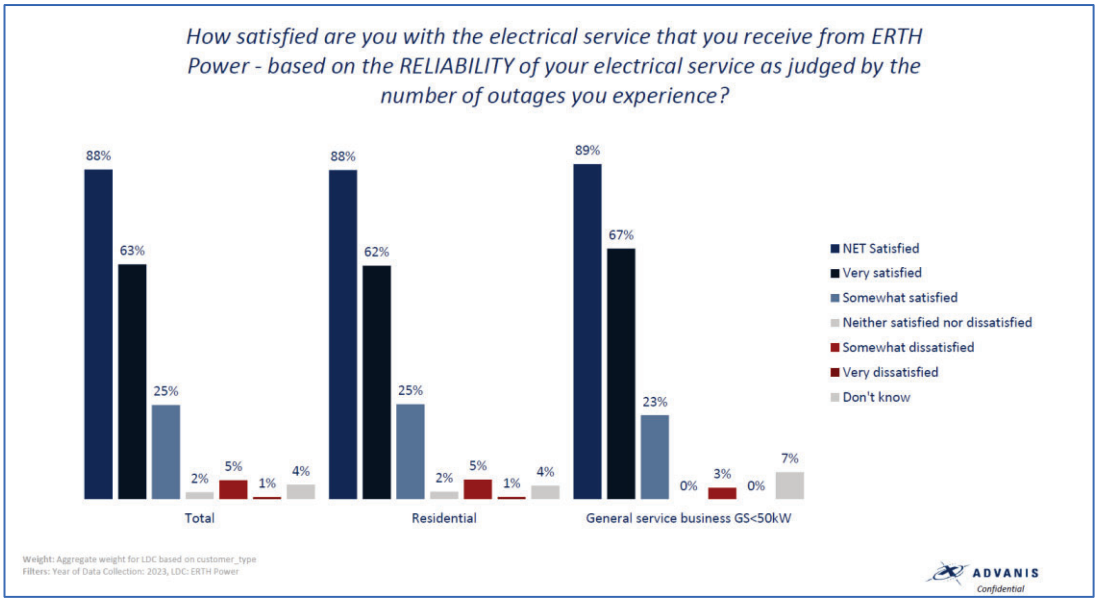
Figure 6: Reasonableness of ERTH Power Costs and Services



Customer Satisfaction with Reliability of Service

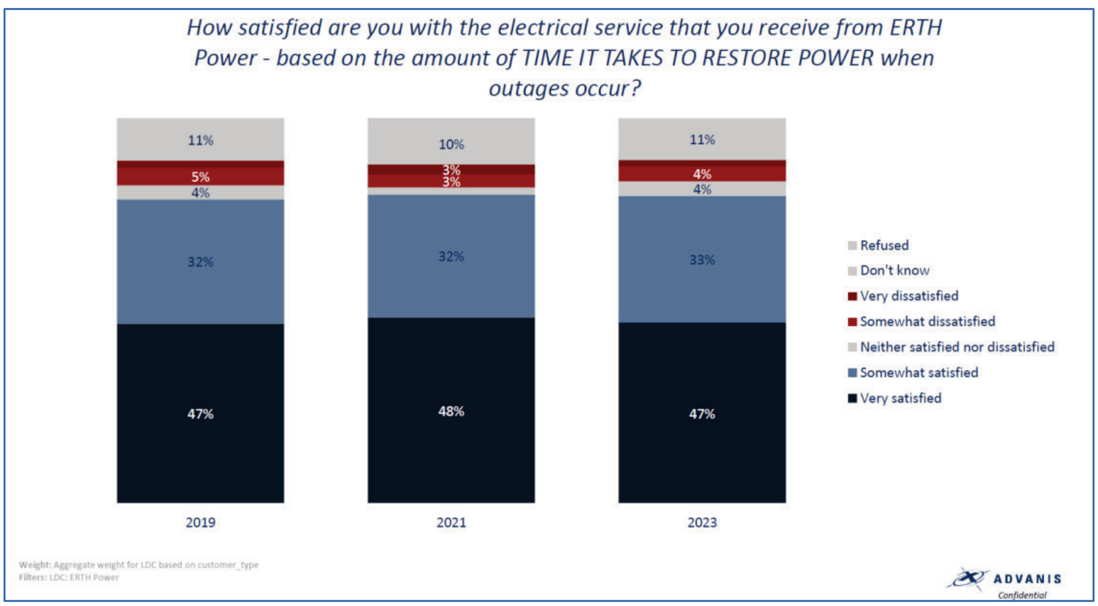
Customers were how satisfied they are with the reliability of the ERTH Power service and 88% of all customers responded with either "very satisfied" or "somewhat satisfied" with only about 4% not having an opinion. This reinforces the idea that reliability is the main concern for ERTH Power's customers other than cost. (See ***Figure 7***).

Figure 7: Satisfaction with Reliability



The same question has been asked in previous surveys and a comparison of the results reveals that the customer's satisfaction with the reliability supply has been constant since 2019. (See ***Figure 8***).

Figure 8: Satisfaction with Reliability Since 2019



Results and Impacts on the Plan

The results of the customer survey reinforce the common theme that customers care about rates and reliability above all else. There is also a general lack of understanding of ERTH Power's role in the delivery of electricity to the customer so there is some value in continuing to communicate on issues relating to electricity.

5.2.2.2 Large Customers

The ERTH Power electricity distribution team maintains strong, ongoing relationships with our large customers, despite the absence of formal documentation. We prioritize frequent, informal communication, ensuring that we are always available to address any concerns or provide support. This approach fosters a responsive and accessible service model, allowing us to quickly adapt to our customers' needs while building trust and collaboration. We take pride in being reachable at all times, which reinforces our commitment to reliable, customer-centered service. This was evident in a recent project where the GM-CAMI facility in Ingersoll completed a large investment in an EV battery assembly plant that will nearly double their expected load. ERTH Power was available with a phone call and able to work through the project with little issue and enable their project within very tight timelines.

5.2.2.3 Subdivision Developers

Coordination with subdivision developers involves detailed planning for new connections and infrastructure expansions. ERTH Power works closely with developers to ensure that the necessary distribution infrastructure is in place to support new residential and commercial developments, facilitating smooth and timely connections. This collaboration includes joint planning sessions, design reviews, and regular updates on project progress to ensure alignment with development timelines and requirements.

ERTH Power receives notifications from our municipalities regarding Official Plan Amendments, Draft Plan reviews, severances, zoning changes etc. We are able to provide comments and ensures we are aware of future projects. ERTH Power will proactively reach out to developers when know to understand their plans, timing etc. and ensure our capital projects are coordinated if necessary, and to provide high-level guidance on any issues that may be present for electrical service. These consultations can be initiated by our municipalities, developers, or ERTH Power and the purpose is to ensure proper planning is achieved with developers ensuring electrical servicing can meet technical and timing requirements as an outcome.

5.2.2.4 Municipalities

ERTH Power collaborates closely with municipal governments to align infrastructure projects with municipal development plans. This coordination involves road widening projects, utility relocations, and other public works that may impact the distribution system. ERTH Power participates in municipal planning meetings and provides input on infrastructure needs to ensure that investments support broader community goals and development initiatives.

ERTH Power maintains a good working relationship with our various municipalities, which include the Town of Goderich, Municipality of Central Huron (Clinton), Township of West Perth (Mitchell & Dublin), Township of East-Zorra Tavistock (Tavistock), Township of Zorra (Embro & Thamesford), Township of Norwich (Otterville, Burgessville & Norwich), Town of Ingersoll, Township of Southwest Oxford (Beachville), Municipality of Central Elgin (Belmont & Port Stanley), Town of Aylmer, in addition to Huron County, Perth County, Oxford County, & Elgin County. ERTH Power works closely with all of our municipalities on a yearly basis to coordinate capital projects, new developments etc. Each year prior to developing our capital plan, we reach out to each municipality to understand their plans and ensure our capital plans are coordinated and to understand any expected facility relocation request that are expected.

Municipal UCC (Utility Coordination Committee) meetings are initiated by various municipalities within ERTH Power's service territory and are typically quarterly or bi-annually. The purpose of a Utility Coordinating Committee (UCC) is to facilitate communication and collaboration among utility companies, government agencies, and other stakeholders involved in infrastructure projects. The outcome is to minimize conflicts and disruptions by coordinating the planning, design, and construction of utility installations, such as gas lines, water mains, telecommunications, and electrical systems. This coordination helps ensure that utilities are installed efficiently and safely, reducing the risk of costly delays, accidents, and service interruptions. It also allows ERTH Power to identify conflicts with our infrastructure and properly plan/budget for facility relocation projects. ERTH Power actively participates within UCC's for the Town of Goderich, Town of Ingersoll and Municipality of Central Elgin. Other municipalities serviced by ERTH Power do not currently have formalized UCC meetings however, ERTH Power maintains a good working relationship with all municipalities and discusses upcoming projects throughout the year.

5.2.2.5 Transmitter/Regional Planning Process

ERTH Power participates in the Regional Infrastructure Planning (RIP) process, working with transmitters and the Independent Electricity System Operator (IESO) to address regional energy needs through coordinated infrastructure investments and planning. This collaboration helps identify and address regional constraints and opportunities for system optimization. ERTH Power contributes to regional planning studies, provides data on load forecasts and infrastructure capabilities, and aligns its investment plans with regional priorities and recommendations.

The Ontario Energy Board (OEB) mandated the implementation of a regional planning process in 2013, it is initiated by Hydro One Transmission Planning with a purpose to facilitate transparent, coordinated, and cost-effective planning of regional electricity infrastructure at a transmission level across 21 distinct regions within Ontario. The outcome of the process is typically a Regional Infrastructure Plan (RIP) that outlines required investments in the transmission system of that region. ERTH Power participates in two (2) regional planning groups: the London Area and the Greater Bruce/Huron Area.

The London Area has completed two (2) planning cycles (2015 & 2020) with the latter being completed with the publication of the Regional Infrastructure Plan (RIP) report in August of 2022, which is included in ***Appendix B.*** The next planning cycle for this region has been initiated in 2024 due to projected needs in the area. ERTH Power has not required any capital investment as a result of the first two cycles of Regional Planning.

The Greater Bruce/Huron Area has completed two (2) planning cycles (2016 & 2019) which were completed with a RIP in April 2022, which is included in ***Appendix C***. The next planning cycle for this region has just recently commence in April 2024. ERTH Power has not required any capital investment as a result of the first two cycles of Regional Planning.

In all of ERTH Power service territories the supply point is a wholesale metered distribution connection to the Hydro One Distribution or Transmission system. As a result, ERTH Power and HONI are frequently in discussion regarding operational and planning objectives. These discussions are initiated by either party as needed and the purpose is to ensure that outages, construction projects and maintenance are coordinated with an outcome of reduce outages and efficiency. This includes the yearly Hydro One Large Customer Conference & the semi-annual ISOC TSOG (Integrated System Operating - Transmission System Outage Groupings) Center Customer Conference.

ERTH Power also frequently communicates with our Account Executive at Hydro One to address any ongoing concerns or issues. This often includes supply point reliability, and any operational issues and contact is typically initiated by ERTH Power.

There are no capital projects being planned by ERTH Power as a result of recommendations in either RIP or as a result of discussions with Hydro One at this time.

5.2.2.6 Other LDC's

Coordination with neighboring Local Distribution Companies (LDCs) involves sharing infrastructure and operational data to optimize regional grid performance and reliability. Joint planning sessions and data-sharing agreements facilitate effective cross-boundary load management and emergency response coordination. ERTH Power engages in regular meetings with neighboring LDCs to discuss joint projects, operational challenges, and opportunities for collaboration to enhance regional grid resilience and efficiency.

All of ERTH Power service territories are embedded in HONI territory, and therefore with the exception of Regional Planning, there is no other need to coordinate with LDCs.

5.2.2.7 IESO

ERTH Power works closely with the IESO to align its DSP with the Integrated Regional Resource Plan (IRRP). This alignment ensures that ERTH Power's investments support regional energy reliability, efficiency goals, and long-term sustainability objectives. The DSP includes specific initiatives that align with the IESO's regional planning recommendations. ERTH Power collaborates with the IESO on load forecasting, demand response programs, and renewable energy integration to ensure a coordinated approach to regional energy planning.

The Southern Huron-Perth Sub-Region completed a planning cycle completed in 2021with the publication of the Integrated Regional Resource Plan (IRRP) report in September of 2021, which is included in ***Appendix D.***

While there are some upgrade projects in the area at the transmission level, there are no capital projects being planned by ERTH Power as a result of recommendations in the IRRP or as a result of discussions with the IESO at this time.

5.2.2.8 Telecommunication Entities

ERTH Power has conducted consultations with telecommunications entities operating within its service area to ensure that infrastructure projects are planned and executed without disrupting telecommunication services. This includes identifying potential conflicts and developing mitigation strategies to maintain seamless service delivery. ERTH Power works with telecommunications providers to coordinate the placement of poles, underground ducts, and other shared infrastructure to optimize the use of space and minimize disruptions.

ERTH Power works with many telecommunications entities across its service area. The following (***Table 6***) indicates the date of most recent coordination meeting where relevant and any activities arising from the meetings.

Table 6: Coordination with Telecommunication Entities

	Most Recent Date	Activity
ASHIP- Xplore Inc	Multiple	Shared Project Platform One Pole Permit in Process Establishing Joint Use Agreement Small Projects expected
Rogers	May 27, 2024	No Projects with ERTH Power Territory
Bell Canada	May 24, 2024	No significant needs, on going communications
Eastlink	June 4, 2024	No Major Capital work, small projects on as need basis.
Execulink	June 12, 2024	Minor project in future (Oxford Lane)

5.2.2.9 Renewable Energy Generation

ERTH Power has submitted our Renewable Energy Generation Plan to the IESO detailing the ***Appendix E.*** ERTH Power participates in Regional Infrastructure Planning (RIP) in both the London Area and the Greater Bruce/Huron Area and as of spring 2024, both areas are commencing a planning process.

5.2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

ERTH Power's continuous improvement objectives focus on enhancing system reliability, operational efficiency, and customer satisfaction. This section reviews the achievements and areas for improvement from the previous DSP, detailing specific measures taken to address gaps and ensure ongoing performance enhancement. ERTH Power tracks key performance indicators (KPIs) related to system reliability, service quality, and customer satisfaction, using this data to inform planning and investment decisions.

5.2.3.1 Distribution System Plan

ERTH Power sets objectives to measure for continuous improvement in the areas of Service Quality and Reliability. Service Quality measures are reported annually to the OEB and consolidated into the

Scorecard for comparison across Ontario. Reliability Metrics are reported within the Scorecard and are analysed in detail in the ERTH Power Reliability Report; see ***Appendix F***.

In the DSP filing of 2017, it was identified that the Service Quality metrics were being met. ERTH Power's Reliability Metrics indicate a high value for Customer Average Interruption Duration Index (CAIDI), which is generally a measure of how long an outage endures once it happens.

ERTH Power identified the high CAIDI being largely a result of size of the service area and the time required to locate and isolate faults. ERTH Power committed to the following projects to reduce CAIDI:

- Fault Indicator Installation to reduce fault locating time,
- OMS implementation to quickly connect customer calls to likely outage causes,
- Automated switches to reduce the customers being affected by sustained outages (by restoring as many customers as possible within the first minute).

Due to the generally infrequent nature of large outages, spread across multiple municipalities it is difficult to provide reasonable quantitative analysis however on multiple occasions the installation of SCADA enabled fault indicators and smart switches have lead to improved reliability to our customers. A few examples include:

- Fault indicators in multiple communities have allowed ERTH Power to dispatch crews prior to calls from customers improving our response times. It has also allowed us to not dispatch crews and communicate directly with Hydro One regarding upstream Loss of Supply when the fault did not occur in our system.
- Port Stanley Automated Switch Installation installed at 4kV station, which was previously protected with no reclose functionality. A momentary fault would result in a permanent interruption and minimum 2hr outage to respond to Port Stanley and restore the protective device. With the automated recloser, customers experienced only a momentary interruption and prevents unnecessary crew dispatches. This device has operated six (6) times in 2024 maintaining service to 286 customers and saving approximately 34,320 customer minutes of outages.
- May 20, 2023 - Ingersoll - 768 customers experienced a 1.5hr outage due to an MVA. An automated switch sectionalized the feeder, and 2,337 customers did not experience the outage who previously would have. This event saved approximately 350,550 minutes of customer outage time.
- June 25, 2024 - Ingersoll - 778 customers experienced a 10hr outage due to a wind storm, an automated switch sectionalized the feeder and approximately 2,337 customers did not experience the outage; it is reasonable to assume that with response times, patrolling and manual switching they would have experienced a 2hr outage - as a result approx. 280,440 customer minutes of customer outage time was avoided.

5.2.3.2 Service Quality and Reliability

Service quality and reliability metrics for the past five years are documented, including System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). This section provides explanations for any material changes in service quality and outlines how the DSP addresses these issues to ensure high service standards are maintained. It includes historical performance data, trend analysis, and strategies for continuous improvement in service reliability. ERTH Power also reports on customer outage duration and frequency, providing insights into the effectiveness of past investments and operational improvements.

5.2.3.2.1 Service Quality

Service Quality Metrics are defined by the OEB Scorecard process. See ***Figure 9*** for ERTH Power's latest scorecard (2023)

Customer Focus

The Customer Focus metrics are those that track if services are provided in a manner that responds to identified customer preferences. Customer Focus metrics include

- **Service Quality,** including: Services Connected on Time, Scheduled Appointments Met, and Telephone Calls Answered, and
- **Customer Satisfaction,** including: First Contact Resolution, Billing Accuracy, and Customer Satisfaction Survey Results.

ERTH Power's metrics in this area exceed industry targets in all measures. All metrics show a slight diminishing trend but remain well above the target. ((See Section 5.2.2.1 for complete details of the Customer Satisfaction Survey, See ***Appendix A*** for the survey report.)

Operational Effectiveness

Operational Effectiveness metrics are those that track if productivity and cost performance is achieved and ensure that distributors are delivering on system reliability and quality objectives. Operational Effectiveness metrics include:

- **Safety,** including: Public Awareness, Compliance with Ontario Regulation 22/04, and Serious Electrical Incident Indices,
- **System Reliability,** including: SAIDI (Average Customer Hours of Interruption), and SAIFI (Average Number of Customer Interruptions),
- **Asset Management,** defined as DSP Implementation Progress, and
- **Cost Control,** including Efficiency Assessment, Total Cost per Customer, and Total Cost per km of line.

ERTH Power's metrics in this area are based on the OEB Scorecard formulations and show a "flat" acceptable trend with the exception of the reliability metric (CAIDI) which continues to be below target but improving. See Section 5.2.3.2.2 for a fulsome discussion of the reliability metrics.

Public Policy Responsiveness

Public Policy measures are those that demonstrate the distributors are meeting their obligations mandated by government. Public Policy initiatives currently include:

- **Connection of Renewable Generation,** including: Renewable Generation Connection Impact Assessments Completed on Time and New Micro-embedded Generation Facilities Connected on Time.

ERTH Power's metrics are 100% in this area and exceed industry targets in all measures. In some years there were no requests and therefore no results to publish.

Financial Performance

Financial Performance measures are those that demonstrate the distributor's financial viability is maintained and that savings from operational effectiveness are sustainable. Financial Performance metrics are:

- **Financial Ratios,** including: Liquidity, Leverage, and Profitability.

ERTH Power's metrics in this area are based on the OEB Scorecard formulations and exceed targets in all measures.

Figure 9: 2023 ERTH Power Scorecard

Scorecard - ERTH Power Corporation 9/12/2024

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		97.60%	98.59%	95.84%	97.05%	95.76%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	99.06%	100.00%	99.18%		90.00%	
		Telephone Calls Answered On Time		96.52%	95.92%	95.02%	92.54%	93.49%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.85	99.58	99.26	99.43	99.66			
		Billing Accuracy		98.49%	99.75%	99.85%	99.62%	99.69%		98.00%	
		Customer Satisfaction Survey Results		77.1	77%	77 %	76 %	76			
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		85.10%	85.10%	84.40%	84.40%	83.90%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	1	1	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.229	0.226	0.000	0.000			100.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.94	0.78	2.17	0.93	1.31			0.91
		Average Number of Times that Power to a Customer is Interrupted [2]		0.56	0.29	0.87	0.47	0.38			0.39
	Asset Management	Distribution System Plan Implementation Progress		108%	106.8%	104.5%	95.1%	100.7			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$691	$680	$676	$720	$813			
		Total Cost per Km of Line [3]		$36,992	$36,142	$35,797	$38,366	$44,313			
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%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.76	0.77	0.73	0.65	0.52			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.00	0.90	0.86	0.80	0.83			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.00%	9.00%	9.00%	9.00%	9.00%			
			Achieved	12.05%	8.35%	9.06%	9.72%	9.32%			

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

5.2.3.2.2 Reliability

ERTH Power publishes reliability targets and performance to guide investment decisions and operational improvements. Any deviations from the targets are analyzed to inform future planning and corrective actions. The data has been calculated as stipulated in section 2.1.4.2 of the OEB's Reporting and Record Keeping Requirements.

The DSP includes a detailed analysis of reliability metrics, customer satisfaction surveys, and feedback mechanisms to ensure alignment with customer expectations. ERTH Power also benchmarks its performance against industry standards and best practices, using these benchmarks to identify areas for improvement and drive continuous enhancement of service quality and reliability.

ERTH Power has produced a Reliability Study, which is attached as ***Appendix F;*** the Reliability Study covers the period from 2018 to 2023. Key sections of the Reliability Study are discussed below.

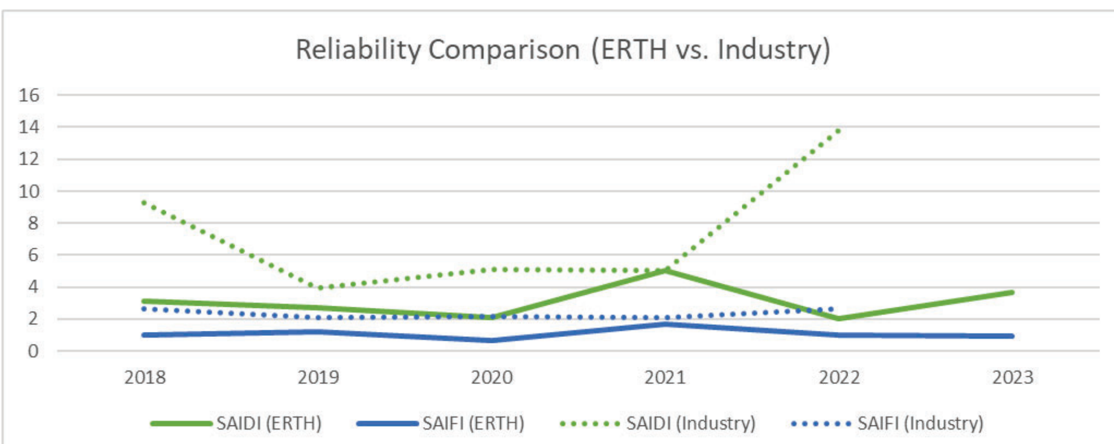
Definitions

- **System Average Interruption Duration Index (SAIDI):** the minutes of non-momentary electric interruptions, per year, the average customer experienced.
- **System Average Interruption Frequency Index (SAIFI)**: It is the number of non-momentary electric interruptions, per year, the average customer experienced.
- **Momentary Outages**: typically refers to a brief interruption in electrical service, generally defined as an interruption of less than one minute in duration.
- **Major Event Days or Major Events (MEDs):** a large event (single day or continuous) causing large customer outages (number and/or duration) that when evaluated as per the prescribed IEEE methodology can be separated when reporting reliability metrics. There were no Major Events Days to report in the study period.

SAIDI & SAIFI (Five-Year Comparison)

ERTH Power has calculated SAIDI and SAIFI statistics and compared them to the OEB published Industry Average (see ***Figure 10***). ERTH Power has maintained an average duration index that exceeds Industry norms.

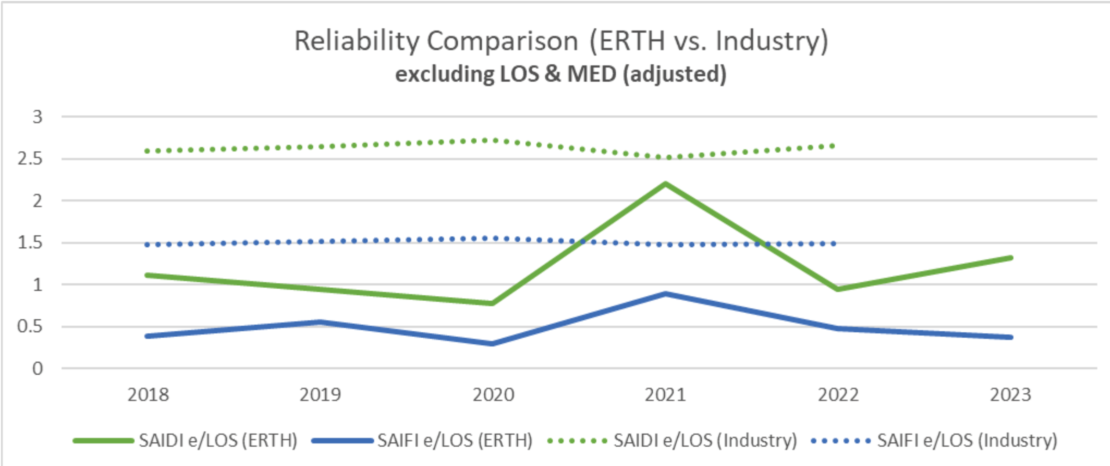
Figure 10: Reliability Comparison – SAIDI & SAIFI



ERTH Power has then calculated SAIDI and SAIFI statistics, adjusted them for Loss of Supply (LoS) events and compared those to the OEB published Adjusted Industry Average. (see ***Figure 11***). ERTH Power has been able to maintain an average duration index that is below Industry norms. Adjusting for LoS events reduces the peak SAIDI (2021) from approximately 5 hours to approximately 2.25 hours. Similarly removing LoS events reduces the SAIFI results from an average of about 2 events in 2021 to less than 1.

LoS events are generally considered to be outside of the control of ERTH Power but make up part of the Customer Satisfaction response.

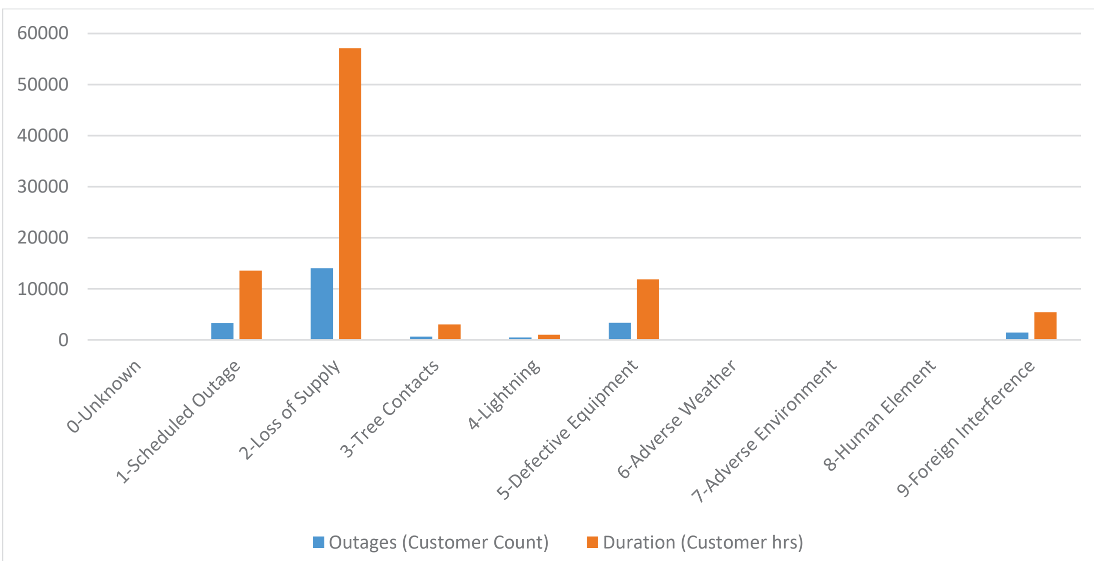
Figure 11: Reliability Comparison – SAIDI & SAIFI (adjusted)



2023 Outages by Cause

Analyzing 2023 outages by cause code (see **Figure 12**) reveals that 63% of the number of outages and 62% of the Customer hours of outage are caused by Loss of Supply. This indicates that LoS events, which effect entire towns, are frequent and long compared to routine distribution system outages.

Figure 12: Outages by Cause Code – 2023

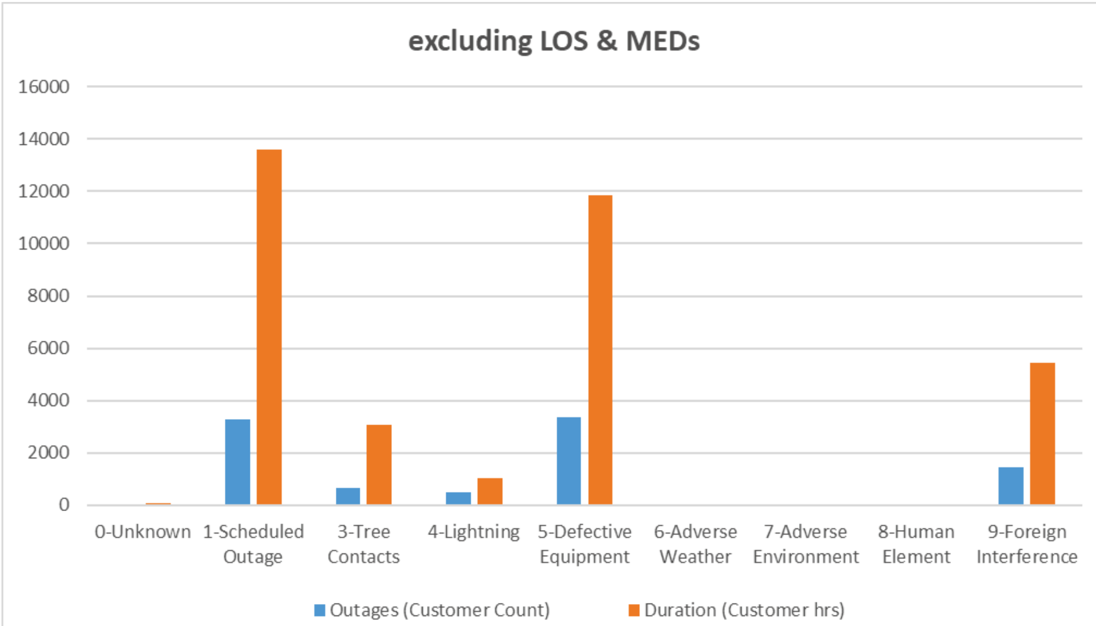


Analyzing 2023 outages by cause code with the Loss of Supply events removed (see ***Figure 13***) reveals that the significant remaining impacts on reliability are:

- Scheduled Outages (35% of the number of outages and 39% of the Customer hours),
- Defective Equipment (36% of the number of outages and 34% of the Customer hours), and

- Foreign Interference: (15% of the number of outages and 16% of the Customer hours).

Figure 13: Outages by Cause Code (adjusted) -- 2023



Worst Performing Feeders

Over the study period, feeder performance is monitored, problems are investigated, and solutions are put into place. Therefore, the most recent years are the best indicators of worst performing feeders. For detailed assessment of feeder performance, please see the Reliability report in ***Appendix F.***

In summary, the worst performing feeders for 2020-2023 are:

SAIDI (Duration)

- **Including LOS** the worst performing feeders have been: 27M3 (Port Stanley) and the 38M49 (Ingersoll).
- **Excluding LOS t**he worst performing feeders have been: 38M50 (Ingersoll – tree contact-weather), 34M3 (Aylmer – equipment failure), CON-F2 (Clinton – scheduled outage) and PTS-F3 (Port Stanley -- various)

SAIFI

- **Including LOS t**he worst performing feeders have been: 38M50 (Ingersoll), 38M49 (Ingersoll), 31M5 (Goderich) and 27M3 (Port Stanley).
- **Excluding LOS** the worst performing feeders have been: the 38M50 (Ingersoll – tree contact-weather), 20M3 (Norwich -- tree contact - weather related, defective switch and unknown), and 34M4 (Aylmer -- tree contact - weather and high winds).

Recommendations (O&M, Capex etc.)

At ERTH Power, a single large event will dramatically affect Reliability Performance. Large events such as the unexpected loss of an important asset, or a foreign interference such as an automobile accident is statistically predictable but impossible to prevent. ERTH Power incorporates industry acceptable practises to minimize outages and where possible investigate outages for continuous improvement.

While ERTH Power's reliability metrics are within target, the following projects are part of this DSP with the intent of continuous improvement:

- Review tree trimming schedule and cutbacks
- Increased pole replacement budget to catch up on bad condition poles
- Porcelain switch replacement programs in capital and as a trouble call policy (Supply chain issues to be overcome)
- Reduce Scheduled Outages via Mobile Substation investment

Reliability oriented recommendations will be part of future system plans, which are likely to include:

- Outages shown in a graphical format (GIS Mapping)
- Recommendation Tracking.
- Momentary Outages - tracking & analysis - investigating options in SCADA system

5.2.3.3 Distributor Specific Reliability Targets

ERTH Power uses the performance targets set out in the Scorecard to report on reliability performance for SAIDI and SAIFI (note: CAIDI can be calculated by dividing SAIDI by SAIFI).

5.3 Asset Management Process

ERTH Power's asset management planning process is comprehensive and data-driven, designed to ensure the effective identification, prioritization, and execution of capital and operational investments. The planning process integrates advanced data analytics, Geographic Information Systems (GIS), and asset management software to provide a detailed and accurate understanding of asset conditions, system performance, and future infrastructure needs.

The planning process involves several key stages:

- **Data Collection and Analysis**: ERTH Power collects extensive data on asset conditions, performance metrics, customer feedback, and operational requirements. This data is analyzed to identify assets that require maintenance, refurbishment, or replacement.
- **Condition Assessment and Risk Analysis**: The condition of major assets, such as transformers, conductors, and substations, is assessed through field inspections, testing, and monitoring systems. Risk analysis is conducted to determine the likelihood of asset failures and their potential impact on system reliability and customer service.
- **Identification of Needs and Prioritization**: Based on the condition assessment and risk analysis, ERTH Power identifies infrastructure needs and prioritizes them according to their criticality, impact on service quality, and alignment with strategic objectives. This prioritization ensures that the most critical projects are addressed first, optimizing the allocation of resources.
- **Investment Planning and Optimization**: Detailed investment plans are developed for prioritized projects, including cost estimates, timelines, and resource requirements. ERTH Power uses optimization techniques to balance capital and operational expenditures, ensuring cost-effective solutions while maintaining high service standards.
- **Implementation and Monitoring**: The execution of planned investments is closely monitored to ensure timely completion and adherence to budget. Performance metrics and project outcomes are tracked to evaluate the effectiveness of the investments and inform future planning decisions.

5.3.1 PLANNING PROCESS

ERTH Power's planning process for capital investments involves a structured approach to identifying, selecting, prioritizing, and optimizing projects. The process includes the following steps:

- **Identification of Investment Needs**: Investment needs are identified based on asset condition assessments, performance metrics, regulatory requirements, and customer feedback. ERTH Power uses a combination of field inspections, testing, and monitoring systems to gather data on asset conditions and identify areas requiring investment.
- **Selection of Projects**: Potential projects are evaluated based on their alignment with strategic objectives, impact on service quality, and cost-effectiveness. ERTH Power considers factors such as asset criticality, risk of failure, and customer impact in the selection process.
- **Prioritization of Investments**: Projects are prioritized based on their criticality, potential impact on system reliability and customer service, and alignment with regulatory and strategic goals.

ERTH Power uses risk-based prioritization techniques to ensure that the most critical projects are addressed first.

- **Optimization of Capital Expenditures**: Detailed investment plans are developed for prioritized projects, including cost estimates, timelines, and resource requirements. ERTH Power uses optimization techniques to balance capital and operational expenditures, ensuring cost-effective solutions while maintaining high service standards.
- **Pacing of Execution**: The execution of planned investments is carefully paced to align with budget constraints, resource availability, and operational requirements. ERTH Power monitors the progress of projects to ensure timely completion and adherence to budge

5.3.1.1 Overview of Planning Process

ERTH Power's corporate structure requires it to prudently manage its resources to balance the needs of customers with the objectives of the shareholder. The sole shareholder of ERTH Power is ERTH Corporation, which is owned by nine (9) municipal shareholders in communities we service. The Directors of ERTH Corporation (Shareholder) are representatives of each of the nine municipalities (typically elected officials), who are responsible to represent their respective municipalities (residents/customers) as an investor (Shareholder) and a provider of affordable essential distribution services. Thus, the performance and planning of ERTH Power is regularly reviewed by municipal representatives who provide direct input to the ERTH Power Board and Senior Management regarding customer concerns in their respective municipalities.

ERTH Power's Sustainability Commitment:

ERTH Corporation is a dynamic group of companies that delivers products and services within the energy, water and municipal sectors. Given our involvement in providing essential services and the key role we play in our local communities, we recognize the importance of sustainable business practices.

Since our inception in 2000, sustainability has been ingrained in our founding principles, which include local presence and employment and a commitment to the social, environmental and economic needs of our customers, employees and shareholder communities. We believe that these principles are key ingredients in building stronger communities and a more sustainable business.

We understand that our actions impact the communities in which we operate. We also understand that this impact will affect future generations and the prosperity of our shareholder communities. It is important to recognize that the scope of sustainability stretches much further than simply conservation and environmental preservation. Therefore, sustainability to ERTH Power means promoting business practices that are sustainable from an environmental, social and economic perspective.

ERTH Power's Mission:

"As Your Home Town Utility we provide you, our valued customers, with safe and reliable power line services. Our mission and pledge to our customers is to provide exceptional, cost-effective electrical service. We distribute and maintain the flow of electricity to our customers from Ontario's energy grid. We take pride in providing our customers with knowledgeable staff and a dependable and reliable energy distribution system."

Asset Management Objectives:

As an infrastructure-based organization, ERTH Power recognizes that our assets are the key element to providing safe, reliable and cost-effective hydro to our customers. ERTH Power implements a risk-based asset management plan (AMP) enabling the following objectives to be realized through informed asset-based decisions.

- The ability to maintain or improve the reliability of our distribution system
- Long term planning horizons resulting in stabilized financial impacts to customers
- The proper balance between capital investments in new infrastructure and O&M costs ensuring that the total cost over the life of the asset is minimized.

Ranking and Prioritizing Investments:

ERTH Power uses a software-based investment optimization process ("Optimizer") to ensure that planned projects are targeted at portions of the distribution system that have the highest risk and consequence. This allows the objectives set out in the Mission Statement and Sustainability Commitment to be realized while minimizing risk to customers, employees and shareholders.

Each project being considered for capital expenditure is assigned risk based on consequence and probability for a number of categories. The categories as defined in the investment optimizer are explained in detail below, with the associated weighting in percentage.

Financial (11%)

Value - The financial category aims to quantify any financial impacts as a result of the project completion. Consideration is given to the project cost, revenue and cost savings in the form of reduced maintenance, or operating costs.

Risk - the risk assigned under this category is based on the loss of revenue and/or cost avoidance as a result of not completing the particular project. The financial consequences are linked to the probability of an event occurring on a scale ranging from four (4) events a year to one (1) event every ten (10) years.

Service Quality (13% total) - SAIFI (6.5%)

Value - SAIFI quantifies the number of times a customer experiences a power interruption and consideration is given to the current SAIFI trend in the proposed project area.

Risk - risk for SAIFI considers the potential impact to outage frequency resulting from asset failure if the project is not completed. The consequences assigned to the project range from individual customers (<50kW) to transmission feeders (>50% of customers) experiencing an outage and the probability range from four (4) events a year to one (1) event every ten (10) years.

Service Quality (13% total) - SAIDI (6.5%)

Value - SAIDI quantifies the duration of outages experienced by a customer and consideration is given to the current SAIDI trend in the proposed project area.

Risk - risk for SAIDI considers the potential impact to outage duration resulting from asset failure if the project is not completed. The consequences assigned to the project range from a momentary outage (<3min) to a sustained outage (>12 hours) and the probability ranges from four (4) events a year to one (1) event every ten (10) years.

Company Image (8%)

Value - The company image category looks to address any formal complaints made to ERTH Power as a result of a particular portion of the distribution system related to a proposed project.

Risk - the risk assigned under the company image category is based on the consequences of a formal complaint ranging from individual concerns made to the company to general public outcry - national media coverage and again is assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Legal (8%)

Value - the legal category looks to consider the litigation costs related to a particular project.

Risk - the risk assigned to a project under the legal category is based on the litigation costs that may result of a project not being completed. The consequences range from litigation costs of less than $1000 to greater than $500,000, and are assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Regulatory (18%)

Value - The value assigned under the regulatory category looks to consider the impacts of a project on compliance to regulatory requirements.

Risk - the consequences as a result of not completing the proposed project range from non-reportable compliance issues to damaging OEB regulatory impacts resulting in the loss of licence and are assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Public Safety (13%)

Value - The value considered in this category is specific to public safety and looks to quantify the possibility of a safety incident related to a member of the public.

Risk - If the potential project is not completed the consequences range from the potential of a non-life - threatening injury with no prior history to a potentially life-threatening hazard with a known history and assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Employee Safety (13%)

Value - The value considered in this category is specific to employee safety and looks to quantify the possibility of a safety incident related to a utility worker.

Risk - If the potential project is not completed the consequences range from a minor employee injury with internal reporting required to a major loss time injury or fatality and assigned a probability ranging from four (4) events a year to one (1) event every ten (10) years.

Environmental (16%)

Value - the environmental category aims to consider the environmental impacts of the distribution system and to ensure any environmental concerns are mitigated.

Risk - the risk assigned under the environmental category if a project is not completed range in consequence from a minor disturbance with environmental documentation not necessary to a disturbance requiring MOE and third-party environmental assistance. The possible consequences under this category are assigned probability ranging from four (4) events a year to one (1) event every ten (10) years.

5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

Since the last DSP filing, ERTH Power has moved towards a roadmap of process improvement which is in the early stages of implementation. The road map details several significant enhancements to its asset management process:

- **Integration of Predictive Analytics**: Advanced predictive analytics tools have been integrated into the asset management process to improve asset condition monitoring and proactive maintenance planning. These tools enable more accurate predictions of asset failures and optimize maintenance schedules.
- **Enhanced GIS Capabilities**: Upgrades to GIS systems have improved spatial data management and asset tracking. These enhancements provide more accurate and up-to-date information for planning and operational decisions, supporting efficient infrastructure management and investment planning.
- **Advanced Asset Management Software**: The adoption of new asset management software has streamlined data analysis, decision-making processes, and project management. This software integrates data from multiple sources, including GIS, SCADA, and customer feedback, to provide a comprehensive view of asset performance and condition.
- **Improved Stakeholder Engagement**: ERTH Power has expanded its stakeholder engagement practices, incorporating more feedback from customers, municipalities, and other stakeholders into the planning process. This has led to better alignment of infrastructure investments with community needs and customer expectations.
- **Refined Lifecycle Management Practices**: The utility has updated its asset lifecycle management practices, including more detailed asset condition assessment methodologies and lifecycle cost analysis. These practices ensure that investments are data-driven and aligned with long-term strategic objectives.

5.3.1.3 Process

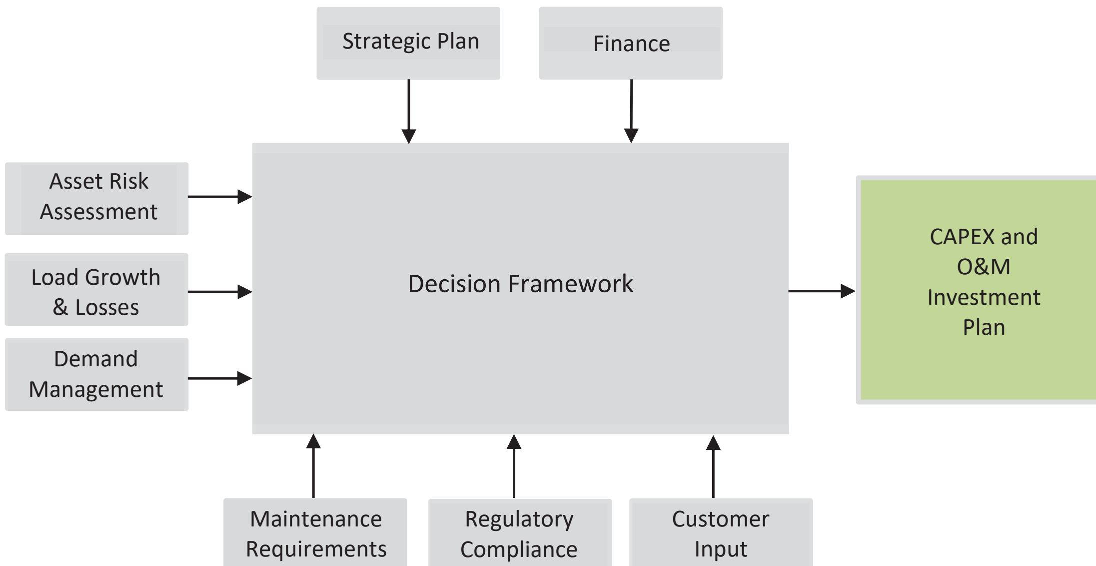
Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments.

To create the annual capital, operating and maintenance plan, ERTH Power uses a risk-based strategy as recommended by METSCO in the original 2011 Asset Management Plan. The diagram below illustrates the various inputs that go into the process used to create the capital plan.

Decision Framework

The decision framework is essentially the "Investment Optimizer" program as detailed in later sections coupled with internal discussion and prioritization as shown in ***Figure 14***

Figure 14: ERTH Power's Decision Framework



Finance

The ERTH Power Board of Directors, in consultation with Senior Management, provide input regarding the overall envelop of spending that is considered appropriate, given the potential impact to customers' rates, shareholder return, and the present and future financial health of the company. This "top down" approach ensures that the resulting investment plan is reasonable and sustainable.

Strategic Plan

The ERTH Power Board and Senior Management Team identify special projects (such as a website update) or areas of focus (such as distribution automation) that may impact the overall investment plan for the coming year. This direction is conveyed to the management team during preliminary budget meetings.

Asset Risk Assessment

Assets are evaluated (some individually, some by sample set, others using age as a proxy) to determine the risk of failure and impact. From this, an average yearly capex replacement amount is created, which forms a starting point for the capital and O&M plan.

Load Growth & Losses

Using historical trend analysis and input from municipal planners and local developers, an estimate is made regarding the amount of load growth (or loss) that will occur in each area. This is typically expressed as the number of new or upgraded customers by type, and an approximate dollar amount is assigned for the expected workload. In some cases, load growth in a specific area may initiate a project to increase capacity or provide an alternate supply.

Electric Vehicles

ERTH Power participates in the Regional Infrastructure Planning (RIP) process, working with transmitters and the Independent Electricity System Operator (IESO) to address regional energy needs through coordinated infrastructure investments and planning. This collaboration helps identify and address regional constraints and opportunities for system optimization. ERTH Power contributes to regional planning studies, provides data on load forecasts and infrastructure capabilities, and aligns its investment plans with regional priorities and recommendations.

On November 2, 2022, the OEB posted the "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG), which provided guidance in the development of demand forecasts to increase consistency among distributors.14 Distributors should consider this guidance when developing their load forecasts. The guidance recommended a sensitivity analysis to capture uncertainty in the demand forecast and noted "one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends. The Regional Planning initiative utilizes this guidance document throughout the process; Hydro One & the IESO utilize a sensitivity analysis to account for electrifications efforts and specifically EV adoption, during the Load Forecasting and Needs Analysis.

Demand Management

Coupled with the load growth analysis, consideration is given to the amount of load that could potentially be reduced by the various conservation and demand management initiatives or offset with distributed generation (including load displacement). Historically, the overall impact of various demand management initiatives has slowed growth such that increased capacity is not normally required, although new customers are added every year.

Maintenance Requirements

Various components of the system require regular maintenance, dictated by asset condition, utilization, manufacturers' recommendations, or good utility practice. Generally, the costs of maintenance increases as the assets age and as the assets are used.

Regulatory Compliance

LDCs must comply with several regulations that directly or indirectly result in capital or O&M work. Some examples include connecting new customers, upgrading meters, making changes to billing systems, inspecting the distribution system, and providing safety training to workers. In many cases, these types of projects do not go through the optimizing process as they must be completed regardless of the ranking results.

Customer Input

ERTH Power regularly solicits input from customers through surveys to assist with developing the annual investment plan. Informal input is also received as employees interact with customers through routine activities such as billing inquiries or when participating in community events or when hosting events such as Conservation Seminars.

Non-Wires Alternatives

ERTH Power considers all options that might defer investment, which includes assessing non-wires alternatives as part of the business case. Assessment is informal at this time, and ERTH Power is moving towards formally documenting non-wires review as part of the mandated OEB process moving forward.

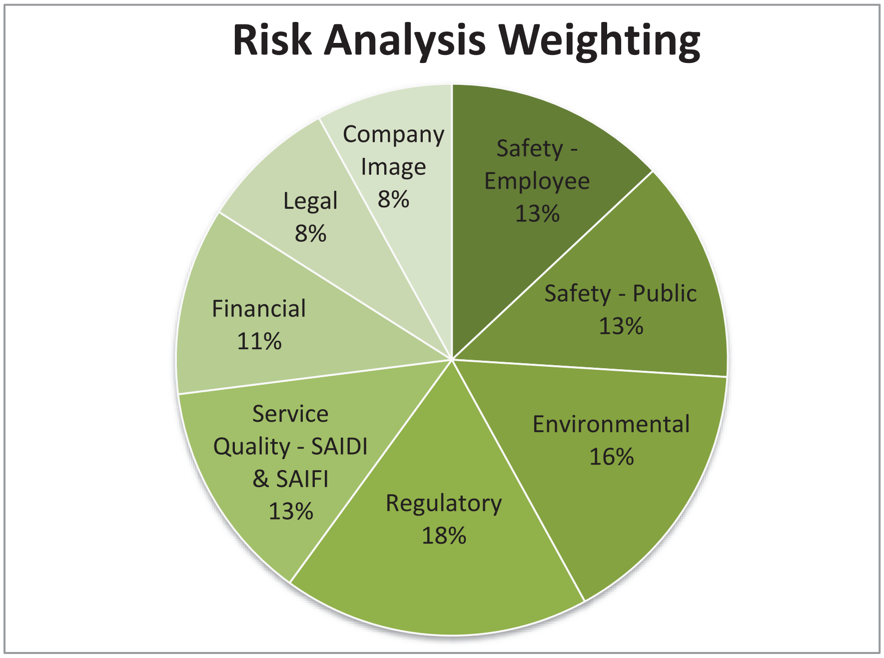
Investment Optimizer

The investment optimizer requires that all categories be assigned importance, and the following figure demonstrates the weighting that has been adopted by ERTH Power in line with our internal and corporate objectives. The categories and weights are reviewed and confirmed by the ERTH Power Board of Directors every two to three years.

Currently ERTH Power utilizes the investment optimizer to complete a yearly optimization of all capital expenditures involving fixed distribution assets. This requires approximately 2-3 years of potential projects to be defined, budgeted and assigned risk. The optimizer then analyzes the available projects and chooses a mix of projects that not only minimize risk but fall within prescribed spending levels. This ensures that projects are identified, selected and prioritized using disciplined risk-based analysis. Projects that are considered mandatory (such as connecting new customers) are excluded from the optimization process.

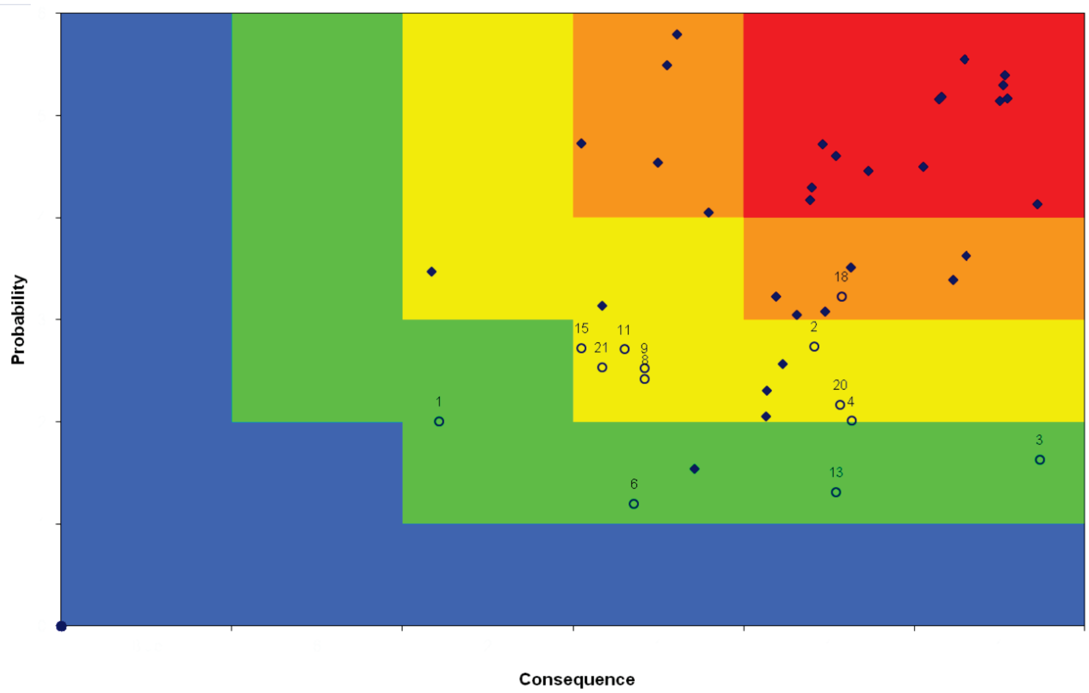
The Risk Analysis Weighting, which aligns with the corporate objectives, discussed in Section 5.3.1.1 is shown as ***Figure 15: Risk Analysis Weighting***

Figure 15: Risk Analysis Weighting



A graphical output from the Optimizer is shown in Figure 16 with the coloured in dots representing projects that were optimized for that year's capital portfolio, and un-filled in dots represent projects that were not and are referred to the subsequent year's prioritization process.

Figure 16: Optimizer Output



The relationships between the corporate goals (ERTH Power Sustainability Commitment, ERTH Power Mission), asset management objectives, the Optimizer categories, and the OEB Outcomes are summarized in the table below.

Figure 17: OEB Outcomes

OEB OUTCOMES				
Customer Focus	Operational Effectiveness	Public Policy Responsiveness	Financial Performance	
local presence, needs of customers	economic needs of customers, sustainable business practices	social and environmental needs, conservation, environmental preservation	sustainable business practices, needs of shareholder	ERTH Power Sustainability Commitment
home town utility, valued customers, safe and reliable powerline services	exceptional electrical service, knowledgeable staff	exceptional electrical service	cost effective electrical service	ERTH Power Mission
maintain or improve reliability, stabilized financial impacts to customers	maintain or improve reliability, long term planning horizons, balance capex and O&M costs	long term planning horizons	stabilized financial impacts to customers, balance capex and O&M costs, total cost over life of asset is minimized	Asset Management Objectives
public safety, SAIFI, SAIDI, financial	SAIFI, SAIDI, employee safety	legal, regulatory, environmental	financial, company image	Optimizer Categories

5.3.1.4 Data

ERTH Power's planning process is supported by a comprehensive dataset that includes asset condition reports, reliability metrics, customer feedback, and financial performance data. This data is critical for informed decision-making and effective investment planning. Specific data used in the planning process includes:

- **Asset Condition Data**: Information on the age, condition, and performance of major assets, such as transformers, conductors, and substations. This data is collected through field inspections, testing, and monitoring systems.
- **Reliability Metrics**: System reliability metrics, including System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These metrics provide insights into the performance of the distribution network and identify areas for improvement.

- **Customer Feedback**: Input from customers collected through surveys, focus groups, and direct consultations. Customer feedback is used to identify service quality issues and prioritize investments that address customer needs and expectations.
- **Financial Performance Data**: Information on capital and operational expenditures, budget constraints, and resource availability. Financial performance data is used to develop cost estimates, optimize expenditures, and ensure alignment with budget constraints.

5.3.2 OVERVIEW OF ASSETS MANAGED

5.3.2.1 Description of Service Area

ERTH Power is a local distribution company operating in Southwestern Ontario representing the amalgamation of ten (10) Public Utilities Commissions and services approximately 25,000 customers in the municipalities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Mitchell, Dublin, Clinton & Goderich.

5.3.2.1.1 Overview of Service Area

ERTH Power's service area encompasses a mix of urban and rural regions in southwestern Ontario. The service area includes diverse customer segments, such as residential, commercial, and industrial customers, each with unique infrastructure and service requirements. ERTH Power's distribution network consists of overhead and underground lines, substations, and smart grid components designed to enhance reliability, efficiency, and operational flexibility. The service area experiences a temperate climate with significant seasonal variations, impacting energy demand and maintenance activities.

ERTH Power's service territory spans north to south a distance of approximately 130km and all municipalities are embedded within Hydro One service territory. ERTH Power maintains three (3) operations centers located in Aylmer, Goderich and Ingersoll with the later retaining all executive, administration, finance, customer service, metering and engineering departments.

5.3.2.1.2 Customers Served

ERTH Power serves approximately 25,000 customers, including residential, commercial, and industrial users. The customer base is diverse, with varying energy requirements and service expectations. ERTH Power's infrastructure planning and investment strategies are designed to meet the needs of all customer segments, ensuring reliable and efficient service delivery. Customer segmentation data and usage patterns are analyzed to inform planning and investment decisions, ensuring that the distribution network can accommodate current and future demand.

5.3.2.1.3 System Demand & Efficiency

The distribution system experiences peak demand during the summer months, driven by residential and commercial cooling needs. ERTH Power employs various strategies to improve system efficiency, including demand response programs, energy conservation initiatives, and the integration of advanced grid management technologies. Detailed demand forecasts and efficiency improvement plans are developed to illustrate the expected impact of these initiatives on system performance and reliability.

The following charts summarize ERTH Power's Demand & Usage.

Table 7: Peak Demand by Year

Peak Demand		
Year	Winter Peak	Summer Peak
2015	104241	109042
2016	100852	111491
2017	108530	106278
2018	104331	109941
2019	111736	111366
2020	105535	118142
2021	106961	113385
2022	108883	110240
2023	91609	103806

Figure 18: Peak Demand Winter vs Summer

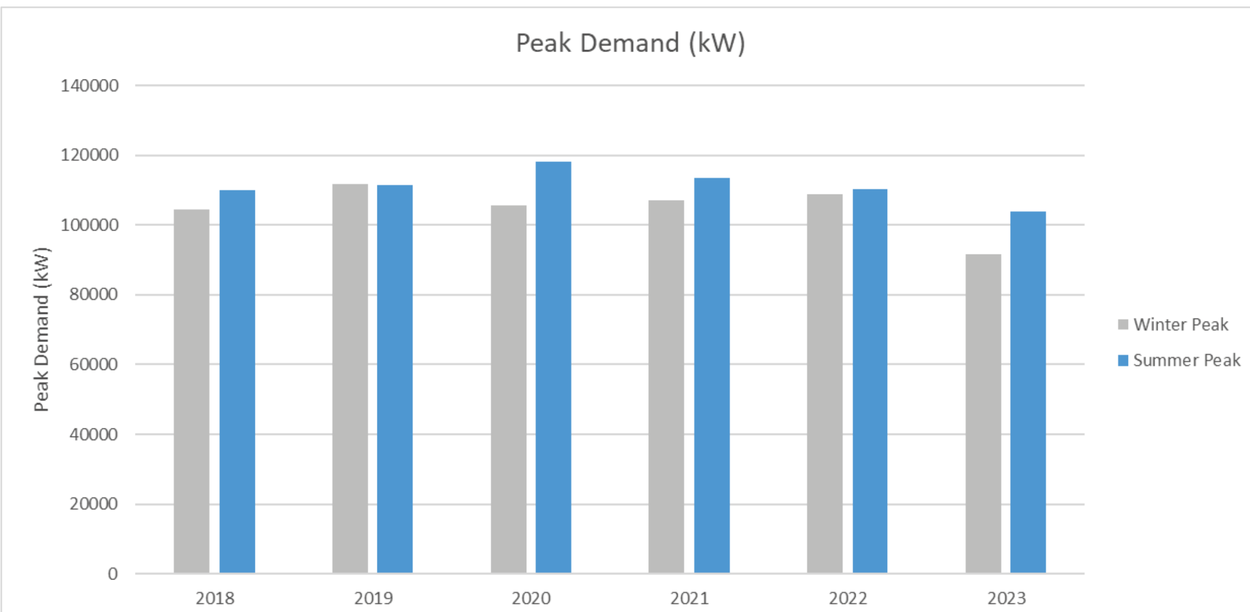
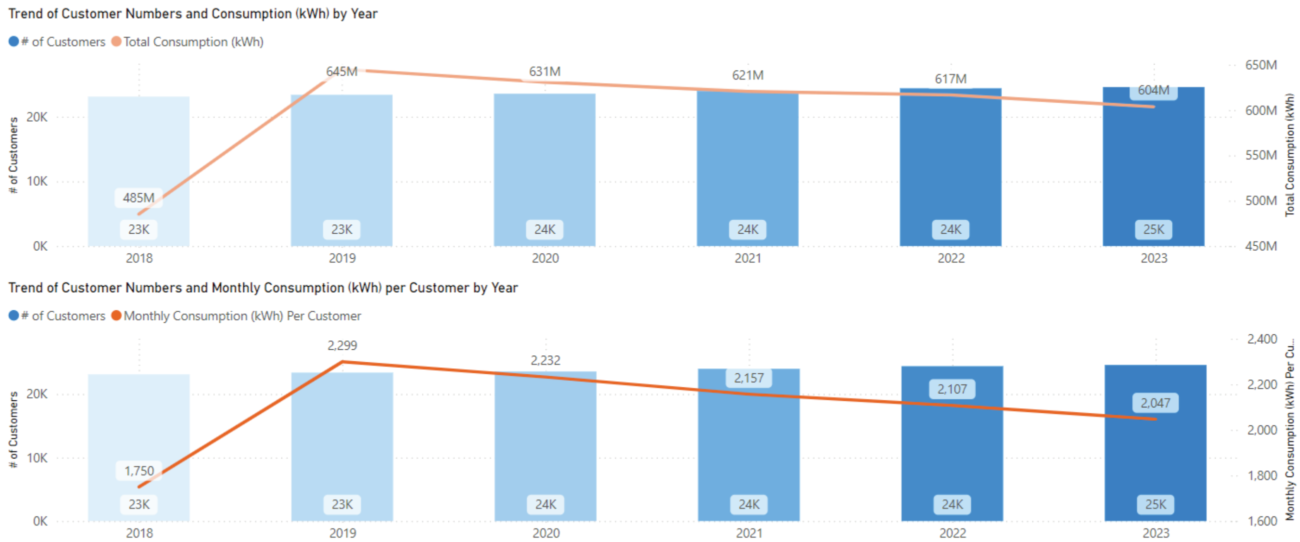


Figure 19: kWh (Consumption) by Year



5.3.2.1.4 Summary of System Configuration

ERTH Power communities are supplied from nine (9) Hydro One owned and operated transformer stations (TS) at 27.6kV along with four (4) Hydro One owned and operated distribution stations (DS) at 8.32kV. Two ERTH Power communities are considered transmission connected (Aylmer, Goderich) and the remainder are embedded within Hydro One distribution. In addition, ERTH Power operates ten (10) municipal substations (MS) supplying customers at 4.16kV. As a result, of this diverse supply, ERTH Power is connected through twenty-five (25) wholesale-metered supply points.

Due to our unique geography, each ERTH Power community has a distinct supply configuration with both advantages & disadvantages. ERTH Power serves low-density urban communities with residential, commercial and industrial customers throughout our service territory. Our customer base includes three (3) large users spread between operations center, including a GM Assembly Plant in Ingersoll, the Compass Minerals Salt Mine in Goderich and IGPC Ethanol Inc. in Aylmer.

ERTH Power's distribution network comprises overhead and underground lines, substations, and smart grid components. The overhead system consists of high-voltage transmission lines and medium-voltage distribution lines that deliver electricity to customers. The underground system includes cables and transformers installed below ground to serve densely populated urban areas and critical infrastructure. Smart grid technologies, such as advanced metering infrastructure (AMI) and automated distribution switches.

5.3.2.1.5 Climate

The service area experiences a temperate climate with distinct seasonal variations, including hot summers and cold winters. These climatic conditions impact energy demand and maintenance activities. ERTH Power's infrastructure planning accounts for these climatic conditions to ensure resilience and reliability. Climate data is analyzed to develop maintenance schedules and prioritize investments that enhance the grid's ability to withstand extreme weather events and maintain reliable service.

Climate is not a specific driver of capital investment in ERTH Power's plan.

5.3.2.1.6 Economic Growth

Steady economic growth in the service area drives the need for infrastructure expansion and upgrades. ERTH Power collaborates with local municipalities and developers to support new residential, commercial, and industrial projects, ensuring that the distribution system can accommodate increased demand. Economic forecasts and growth projections are included to support planning decisions and ensure that infrastructure investments align with community development goals.

5.3.2.2 Asset Information

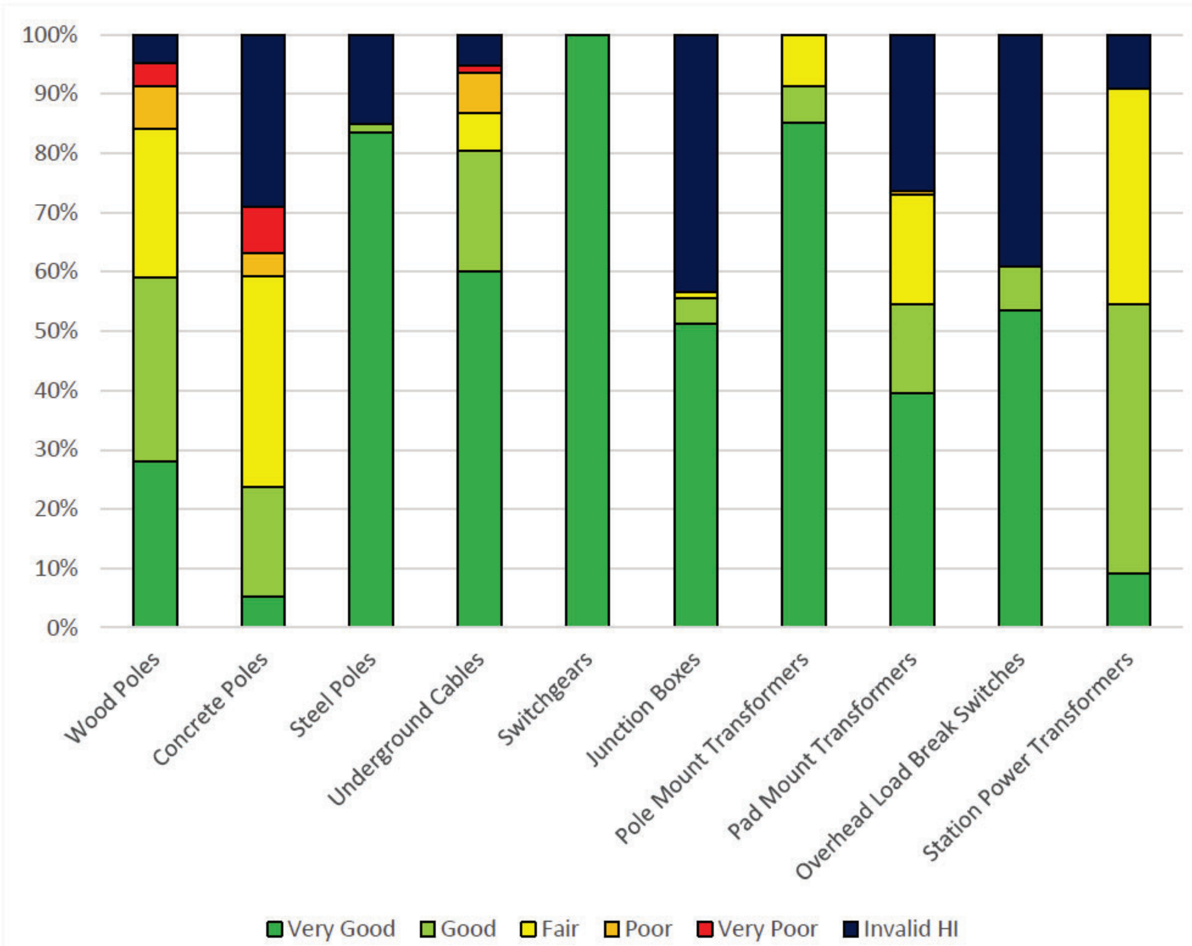
Comprehensive asset information, including data on asset age, condition, performance, and risks, supports informed decision-making and investment planning. This information is critical for optimizing asset lifecycle management and ensuring the reliability and efficiency of the distribution system. Detailed asset registers, condition assessment reports, and risk analysis are provided to demonstrate the utility's commitment to maintaining and enhancing its infrastructure.

ERTH Powers most recent Asset Condition Assessment (ACA) report was completed in April 2024 by BBA E&C Inc. The ACA Report is attached as ***Appendix G*** in its entirety.

Key information from the ACA report is detailed in this section. Key information is considered that which informs the capital investment plan or is otherwise relevant to the planning process.

The overall distribution of the Health Indices on a per-asset basis is represented in **Figure 20.** This figure indicates that the overall condition of the assets is mostly Good or Very Good, and that the assets that need the most investment appear to be Wood Poles, Concrete Poles and Underground cables. The image also indicates that there are some data gaps in the asset condition data shown as "Invalid HI". These gaps are the result of differing maintenance practises across the fifteen (15) municipalities that have been brought together to comprise the ERTH Power System and are being harmonized as well as records allow.

Figure 20: Overall HI Distribution



The following sub-sections present brief summaries of those assets which warrant specific discussion, specifically:

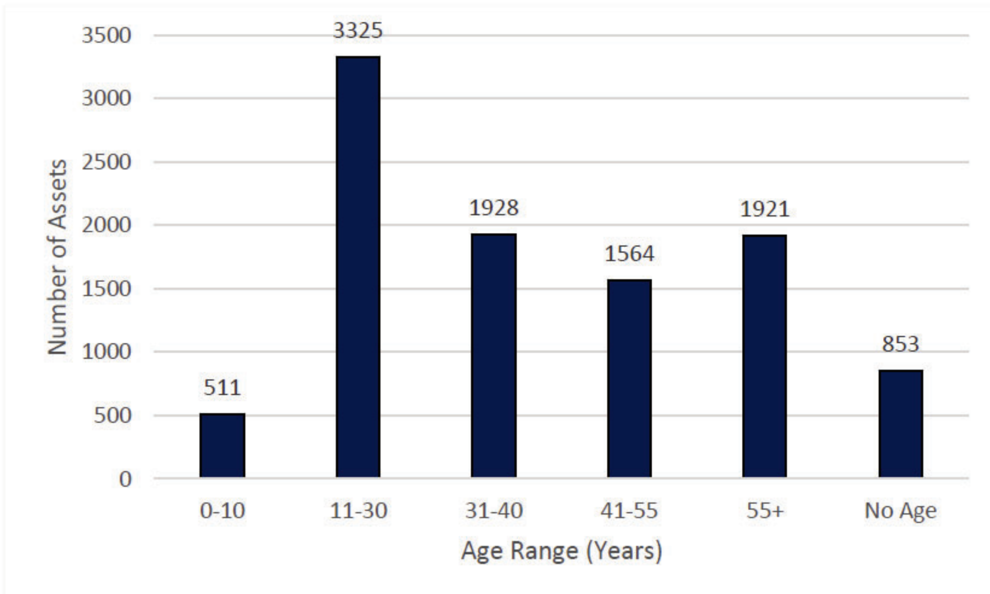
- Wood Poles
- Concrete Poles
- Underground Cables

In addition to the specific capital plans indicated by the Health Index, there are some assets that show a lack of data that would support the decision-making process. ERTH Power commits to increased data collection through targeted projects or routine inspections such that future Health Index project have increased accuracy,

5.3.2.2.1 Wood Poles

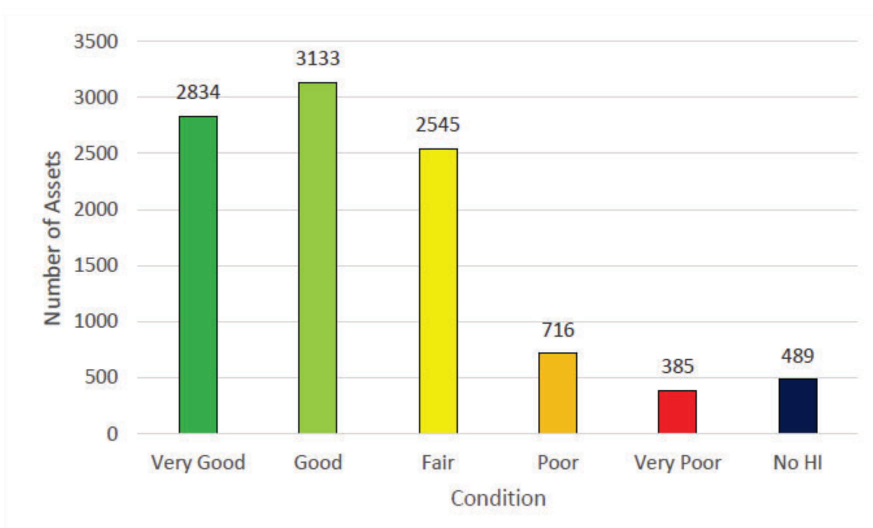
ERTH Power has an inventory of 10,102 wood poles. Wood poles are a significant asset for an LDC due to the vast quantities of poles on the system and the importance of the poles in the delivery of reliable power. Wood poles deteriorate over time, and typically lose strength due to internal rot, splits and cracks, or insect infestations. ***Figure 21*** below details the demographics of the wood poles on the ERTH Power System.

Figure 21: Wood Pole Age Distribution



The ACA report includes a Health Index for assets that considered physical condition parameters beyond just asset age. When asset condition and asset age are not in alignment it can mean that unexpected degradation is taking place. ***Figure 22*** presents the Health Index for Wood Poles.

Figure 22: Wood Pole Health Index



There are 385 Wood Poles in “Very Poor” condition and are in need of replacement over the short term and another 716 poles in “Poor” condition that should be planned for replacement in the medium term. Poles in “Fair” condition or better are not planned for replacement in the planning window. There are

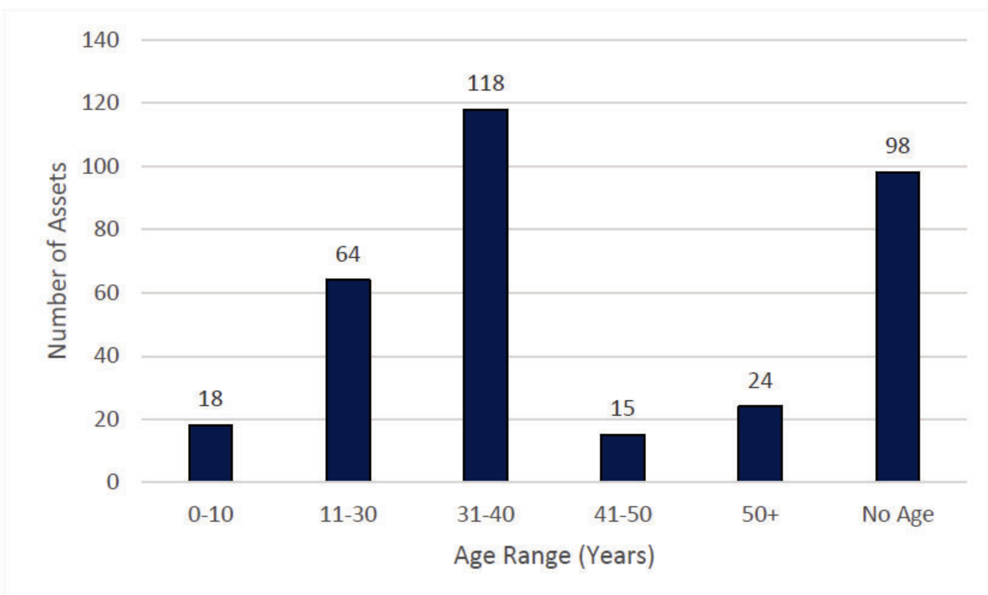
489 poles without a valid Health Index, which is usually something that happens with older assets with poor records. These assets should be high priority to confirm their condition.

When compared to the demographic table, a reasonable correlation can be observed, with the indication that statistically 50% of poles that are older than 55 years old are due for short to medium term replacement. This suggest an asset replacement rate of 1/55 or 1.8%/year, which is a useful planning guide. Since there are approximately 1000 out of 10,000 poles (10%) due for replacement over the next five years, the indication is that System Renewal has been keeping page with degradation.

5.3.2.2.2 Concrete Poles

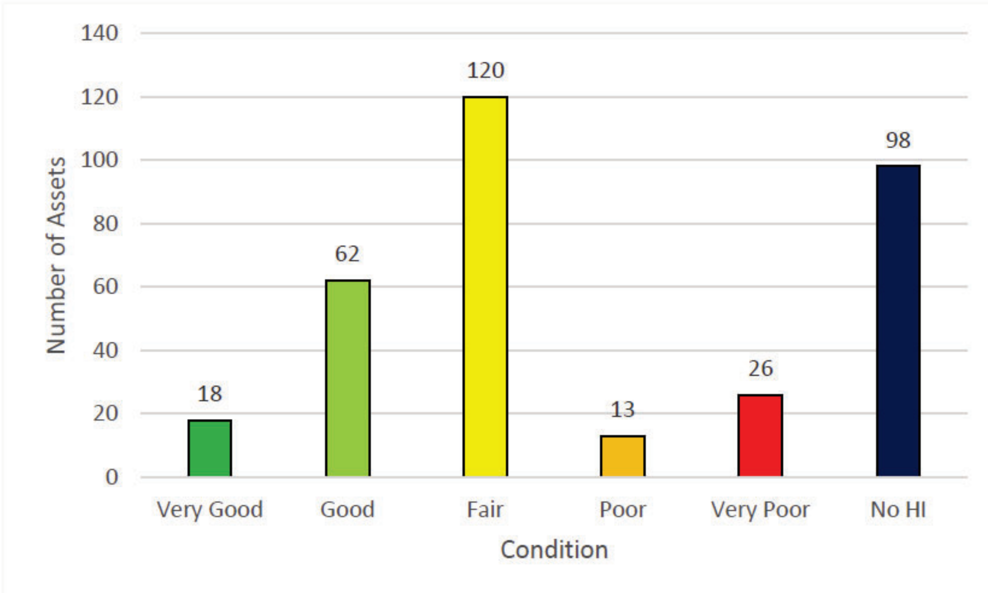
ERTH Power has an inventory of 337 concrete poles. Concrete poles can be a concern for an LDC depending on the use of the pole. In this case, there is a fairly small inventory of the poles but the are located in downtown areas for aesthetics. Concrete poles deteriorate over time, and typically exhibit concrete spalling due to internal rust on the steel rebar internal to the pole. ***Figure 23*** below details the demographics of the concrete poles on the ERTH Power System.

Figure 23: Concrete Pole Age Distribution



The ACA report includes a Health Index for assets that considered physical condition parameters beyond just asset age. When asset condition and asset age are not in alignment it can mean that unexpected degradation is taking place. ***Figure 24*** presents the Health Index for Concrete Poles.

Figure 24: Concrete Pole Health Index



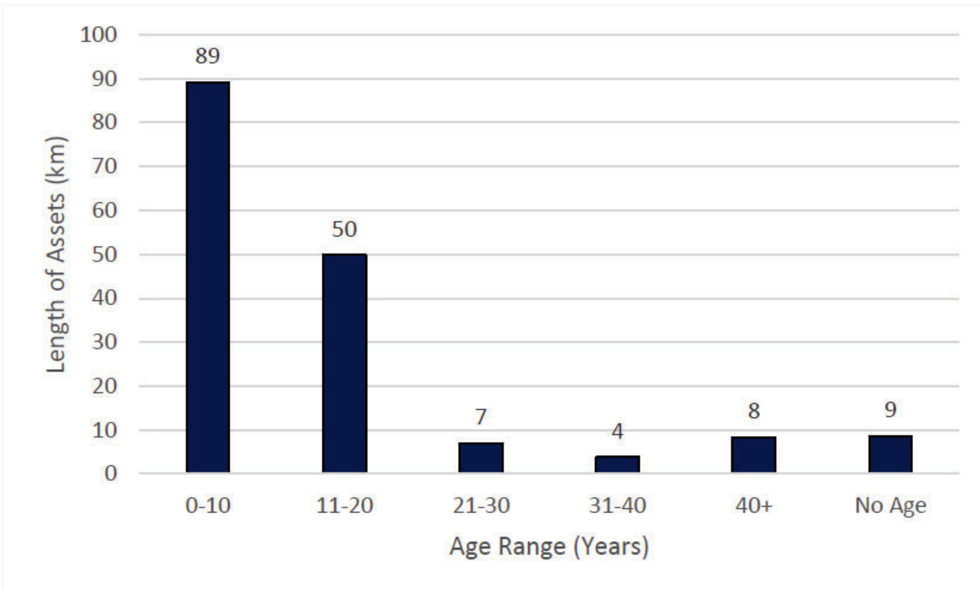
There are 26 Concrete Poles in "Very Poor" condition and are in need of replacement over the short term and another 13 poles in "Poor" condition that should be planned for replacement in the medium term. Poles in "Fair" condition or better are not planned for replacement in the planning window. There are 98 poles without a valid Health Index, which is usually something that happens with older assets with poor records. These assets should be high priority to confirm their condition.

When compared to the demographic table, a reasonable correlation can be observed, with the indication that the poles that are older than 40 years old are due for short to medium term replacement. This suggest an asset replacement rate of 1/40 or 2.5%/year, which is a useful planning guide. Since there are approximately 39 out of 337 poles (11.5%) due for replacement over the next five years, the indication is that System Renewal has been keeping page with Asset degradation.

5.3.2.2.3 Underground Cables

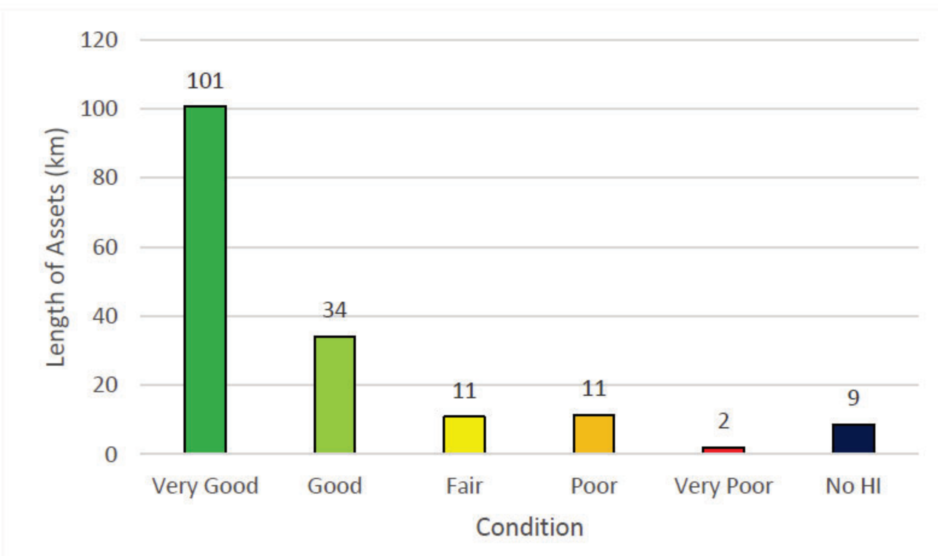
ERTH Power has an inventory of 167 km of underground primary voltage cables. Age data is not expressly recorded many segments (51%) but the ACA reasonably estimates cable segment ages based on adjacent conductors. Underground cables can be a concern for an LDC due to the reliability impact of cable failures and the difficulty in repaired and/or replacing failed and aging cables. Underground cables deteriorate over time, and typically exhibit insulation breakdown or heating connections either of which can lead to a faulted cable section. ***Figure 25*** below details the demographics of the cables on the ERTH Power System.

Figure 25: Underground Cable Age Distribution



The ACA report includes a Health Index for assets that considered physical condition parameters beyond just asset age. When asset condition and asset age are not in alignment it can mean that unexpected degradation is taking place. ***Figure 26*** presents the Health Index for underground cables.

Figure 26: Underground Cables Health Index



There is approximately 2 km of underground cables in "Very Poor" condition and in need of replacement over the short term and another 11 kms in "Poor" condition that should be planned for replacement in the medium term. Cables in "Fair" condition or better are not planned for replacement in the planning window. There are 9 km without a valid Health Index, which is usually something that happens with older assets with poor records. Cables are notoriously difficult to collect data from in the ground, and it is likely that an estimate of age is all that can be obtained.

When compared to the demographic table, a reasonable correlation can be observed, with the indication that the cables that are older than 30 years old are due for short to medium term replacement. This suggest an asset replacement rate of 1/30 or 3.3%/year, which is a useful planning guide. Since there are approximately 13 km out of 167 km (7.8%) km of cables due for replacement over the next five years, the indication is that System Renewal on track relative to degradation.

5.3.2.2.4 Assets without Significant Condition Drivers

The remaining assets were assessed in the ACA process and additional investment for renewal purposes was not indicated. These assets may be renewal incidentally as a result of other renewal projects (for example pole mounted transformers are replaced when poles are replaced), but for the current planning window do not merit additional attention. Assets that do not show significant degradation include:

- Steel Poles
- Switchgear
- Junction Boxes
- Pole Mounted Transformers
- Pad-Mounted Transformers
- Overhead Load Break Switches
- Station Transformers

Some of these assets merit consideration on the basis of age alone and may be considered for renewal projects if there is a significant risk that is not otherwise captured in the condition data. These assets may include:

- Station Transformers [5 units (50%) more than 46 years old]

5.3.2.3 Transmission or High Voltage Assets

ERTH Power does not own transmission assets as all of the ERTH Power assets are at distribution voltages.

5.3.2.4 Host & Embedded Distributors

ERTH Power is neither a host nor an embedded distributor, as all of ERTH Power service territories are embedded in HONI territory,

5.3.2.5 Summary of Major Asset Replacement Levels

The following table summarizes a comparison of two analysis of the ACA results. In Option #1, assets in Poor or Very Poor condition would be prioritized for replacement in the forecast period. In Option #2 the Planning Recommendation was reviewed which looks to correlate the condition data, with the age data of a specific assert class and determine an approximate replacement level. The primary difference in the two analysis is the replacement level of UG Cable and Pad mount Transformers. As noted in section 5.3.2.2.3 when looking at condition data compared to age data, the replacement levels of UG cables are keeping pace with degradation. As a result, ERTH feels it prudent to maintain replacement levels in line with Option #1 over the forecast period.

Table 8: Major Asset Replacement Levels

Asset	Option #1 Replace Poor & Very Poor	Option #2 Planning Recommendation	Unit Replacement Cost ($) Current	Option #1 ($)	Option #2 ($)
Wood Poles	145	167	$11,500	$1,665,200	$1,919,511
Concrete Poles	4	2	$17,500	$77,000	$32,813
Steel Poles	4	6	$15,000	$66,000	$87,000
UG Cable	2.8	5.5	$231,617	$648,528	$1,276,441
Polemount Transformers	30	34	$19,500	$577,467	$656,376
Padmount Transformers	19	37	$30,000	$570,395	$1,122,660
			Total	**$3,604,590**	**$5,094,801**

5.3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

5.3.3.1 Asset Replacement and Refurbishment Policy

A complete description of ERTH Power's asset lifecycle optimization policies and practices are included within the 2024 Asset Condition Assessments included in ***Appendix G.***

5.3.3.2 Description of Maintenance and Inspection Practices

ERTH Power implements various preventative inspection and maintenance programs, which are in line with the urban inspection requirements as required by the DSC. Additional programs such as pole testing, oil sampling, and infrared scans are aimed at reducing reactive unplanned repairs.

Table 9: Inspection & Maintenance Cycles

INSPECTION & MAINTENANCE CYCLES	
O/H Distribution System	3 year
U/G Distribution System	3 year
Substation Inspection (ERTH Power)	1 month
Substation Inspection (Contractor)	6 month
Substation Transformer Oil Sampling	1 year
Substation Maintenance	5 year
Thermograph Scans	2 year
Tree Trimming	3 year
Pole Testing	9 year
Load Break Switch Maintenance	6 year

Overhead Distribution System Inspections - ERTH Power Cycle: 3 years (DSC Requirement: 3 years)

Currently a visual inspection of approximately 1/3 of the overhead distribution system is completed on an annual basis by ERTH Power staff. This includes a visual assessment of the integrity of poles, support structures, switching devices, transformers, lightning arrestors, grounding and any associated hardware. Any basic deficiencies such as missing guy guards or ground moulding are immediately addressed while completing the inspection and other issues are documented and provided to the Operations Manager & Lines Supervisor for prioritization and scheduling.

Underground Distribution System Inspections - ERTH Power Cycle: 3 years (DSC Requirement: 3 years)

Currently ERTH Power staff complete a visual inspection of approximately 1/3 of its underground distribution system on an annual basis. This includes a visual assessment of the integrity of all pad-mounted equipment, cables, terminations and associated civil infrastructure. Any basic deficiencies are immediately addressed while completing the inspection and other issues are documented and provided to the Operations Manager & Lines Supervisor for prioritization and scheduling.

Distribution Substation Monthly Inspections - ERTH Power Cycle: 1 month (DSC Requirement: 1 month)

On a monthly basis ERTH Power staff complete a visual inspection of all substation equipment including transformers, switches, structures, fence, and yard etc. Temperature and current readings are also recorded for transformers and feeders respectively. Again, any basic deficiencies are attended to immediately and other issues are documented and provided to the Operations Manager & Lines Supervisor for prioritization and scheduling as required.

Distribution Substation Bi-Yearly Inspections - ERTH Power Cycle: 6 month (DSC Requirement: None)

Every six (6) months a visual inspection of all substation equipment including transformers, switches, structures, fence, and yard etc. is completed by a third-party contractor. A formal report is created with recommendations for review by ERTH Power. A sample 2023 report included as ***Appendix H*** for reference.

Distribution Substation Transformer Oil Sampling - ERTH Power Cycle: 1 year (DSC Requirement: None)

Oil samples are taken from all distribution station transformers by a third-party contractor; Dissolved Gas Analysis (DGA) and Chemical Analysis (ASTM/Water) are completed and compared to previous tests and IEEE limitations. Oil sampling results are the primary condition indicator for station transformers and are used by Engineering and Operations staff to identify and prioritize stations requiring capital or maintenance investment.

Distribution Substation Maintenance - ERTH Power Cycle: five-year (DSC Requirement: None)

Substation maintenance is completed by a third-party contractor on a five (5) year cycle. This includes inspection, cleaning and service of all electrical and mechanical components, grounding inspection and testing and transformer testing including insulation resistance, capacitance and dissipation factor, turns ratio and winding resistance tests. A formal report is created for review by ERTH Power; a sample 2023 report included as ***Appendix I*** for reference.

Pole Testing - ERTH Power Cycle: 9 year (DSC Requirement: None)

A third-party contractor completes "Sound & Selective Bore" testing on poles which includes sounding of the pole (hammer test) and boring as deemed necessary. Poles are then analyzed, assigned a remaining strength value and prioritized for replacement as required. The remaining strength value is determined using tables developed by the testing contractor and is dependent on the field assessment of the poles. The contributing assessment factors include split top, roof rot, woodpecker damage, shell rot, mechanical damage and others. The tables that are used have been compared with software specializing in analysis of wood pole damage and decay.

In conjunction with pole testing, data collection is completed and used to identify other characteristics of the supporting structure. Examples include identifying porcelain insulators, wood cross arms, & pole top extensions. This data is entered into the GIS system and can then be easily queried to help identify specific areas of concern; the image below is a screen capture of a query identifying poles with a remaining strength < 70% in the town of Port Stanley. In this instance you can visually identify that there are no areas with multiple poor tests requiring capital investment.

Infrared Scans - ERTH Power Cycle: 2 year (DSC Requirement: None)

Infrared inspection completed by a contractor to identify thermal anomaly conditions on overhead distribution system equipment. All anomalies are noted and prioritized based on the temperature rise as compared to the ambient temperature; a sample 2023 report included as ***Appendix J*** for reference.

Load Break Switch Maintenance - ERTH Power Cycle: 6 year (DSC Requirement: None)

ERTH Power completes load break switch maintenance on a 6-year cycle which includes a service of all mechanical and electrical components of the switch. Upon completion of the maintenance work each switch is evaluated to determine if it needs to be replaced prior to the next planned maintenance cycle, and if so, the proposed replacement timing is communicated to the Engineering and Operations Managers for further review.

Tree Trimming - ERTH Power Cycle: 3 year (DSC Requirement: None)

Tree trimming is completed by a third-party contractor and aims to remove approximately 3 years of growth from vegetation in proximity to distribution lines and equipment. ERTH Power staff review conditions before and after to ensure work is completed to recognized standards.

5.3.3.3 Processes & Tools to Forecast, Prioritize & Optimize System Renewal Spending

The vast majority of ERTH Power assets including poles, lines, distribution transformers and associated hardware do not lend themselves to any viable refurbishment options and therefore very few refurbishment practices exist within ERTH Power's asset management plan. In certain situations when a distribution transformer is retired from service it can be refurbished by the manufacturer and returned to stock as a new unit for unplanned type replacements. This type of refurbishment is evaluated on a transformer-by-transformer basis and is only completed if there is a need, and the costs of refurbishment provide savings over purchasing a new unit.

With regards to asset replacement, 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 majority of the investments in fixed assets are triggered by either declining performance in the areas of reliability, power quality and safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In all cases, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal management. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal management. Optimal management of the distribution system is achieved when "right sized" investments into renewal, refurbishment and preventative maintenance are planned and implemented on a "just-in-time" approach.

5.3.3.4 Important Changes to Life Optimization Policies & Practices since Last DSP Filing

The following text is extracted from the 2024 Asset Condition Assessment Report (***Appendix G***).

> In a couple cases, ERTH Power's current asset data records contain less than three degradation factors for each asset class – a numerical threshold that qualifies an asset health score to be formally viewed as an Asset HI. In these cases, we labelled the results of our analysis as two-parameter assessments but presented the results across all asset classes in a consistent format.

Overall, we found ERTH Power to have a material amount of data that enabled us to conduct analysis that should yield meaningful managerial insights to the utility's planners.

With respect to the core distribution utility assets like station power transformers, we were able to construct relatively advanced multi-factor health indices. While comparatively less information is available for some other asset classes, the lack of availability or data diversity relative to other distributors' practices need not be automatically equated to a gap or an oversight on the part of the utility. As with other operating dimensions, utility decisions regarding the scope of data collection represent strategic trade-offs in the environment of multiple priorities and constrained operating costs.

As we note at the outset of this study, ERTH Power is relatively early into its existence, with a long-term approach to AM data collection, and use in decision-making remaining under development. BBA fully expects ERTH Power to consolidate its asset condition collection and analysis activities to determine which additional parameters (if any) it will collect going forward. We expect that ERTH Power will make these determinations based on the recommendations contained in this report, balancing the improvement considerations with the opportunity cost of other activities it will be required to undertake.

5.3.4 SYSTEM CAPABILITY ASSESMENT FOR REG & DERS

Coordination with the IESO and other stakeholders ensures that renewable energy generation projects are efficiently integrated into the distribution system. ERTH Power collaborates with the IESO, other LDCs, and transmitters to align these investments with the regional infrastructure plan and support sustainability goals. This coordination includes joint planning sessions, data sharing, and the development of integration strategies. ERTH Power evaluates the capacity of its distribution network to accommodate renewable energy connections and implements necessary upgrades to facilitate the integration of renewable energy sources.

Currently ERTH Power has 35,992 kW of DER's which are mostly Renewable Energy Generation (REG) within the ERTH Power service territory. While it is understood that not all Distributed Energy Resources (DERs) are based on renewable fuel sources, and also that not all REG's are on the Distribution System, the process for assessing the impact of DERs and REGs is the same if they are distribution connected. However, for the purposes of discussion REG related investment, only REG sources are considered.

The fifteen (15) municipalities of the ERTH Power system are connected to the Hydro One system via various Hydro One distribution circuits and eight (8) Transmission Stations, one (1) high-voltage Distribution Station and three (3) Distribution Stations. Each of these configurations presents unique constraints to the connection of REG/DERs.

When generation is connected to the system, the resulting levels of fault current must be assessed for impact on the lines and stations and thermal considerations must also be studied. Hydro One performs a Distribution Connection Assessment (DCA) to identify impacts on the upstream systems and ERTH Power is responsible for any upgrades required to the ERTH Power distribution system.

In addition to managing short circuit and thermal ratings, it is necessary to avoid "islanding" which is a phenomenon that occurs if they REG/DERs on the line can carry the load even if the source has been disconnected (i.e. a breaker operation at a station). CSA standard 22.3 No 9 which is derived from IEEE

1547 is the standard for DER connections and protections. Generally islanding concerns only occur when the connected generation is near 30% of the minimum load (or approximately 7% of peak load) on a feeder and then is dependent on the type of generation employed.

In May 2024, ERTH Power developed a Renewable Energy Generation (REG) Plan. See ***Appendix E*** for the detailed plan.

Table 10 below shows the ERTH Power REG/DER connections, detailed by connection program:

Table 10: REG/DER Connections

	RESOP	IESO	FIT	MFIT	NET	Load Displacement	Total
Number of Connections	2	1	9	90	22	4	128
Total kW	20000	1800	2613	831	1537	9212	35992

Table 11 below shows the ERTH Power REG/DER connections, detailed by generation type:

Table 11: REG/DER Generation Type

	Solar	Fossil Fuel	Non-Exporting Storage	Exporting Storage	Water	Biomass	Wind	Compressed Gas Storage
Number of Connections	122	2	2	1	0	0	0	1
Total kW	24030	3350	1680	1800	0	0	0	5132

ERTH Power has posted its capacity constraints by feeder on its public website. The current constraints as confirmed by Hydro One Connection Impact Assessments (CIAs) for REG/DER larger than 10 kW are show in ***Table 12*** below.

Table 12: >10 kW Constraints

Service Territory	Transformer Station	Feeder	Feeder Limit kW (Max 400A, 200A)	Remaining Generation Capacity (kW)	Hydro One Station and Feeder Capacity
Aylmer	Aylmer TS	M3	19,121	15,650	15,000
Aylmer	Aylmer TS	M4	19,121	19,095	15,000
Aylmer	Aylmer TS	M5	19,121	19,121	15,000
Beachville	Ingersoll TS	M44	19,121	19,074	15,640
Belmont	Buchanan TS	M21	19,121	0	Constrained
Burgessville	Norwich North DS (via Tillsonburg TS)	F2 (Tillsonburg M3)	2,882	2,882	2,720
Clinton	Constance DS	F2	19,121	16,094	14,250
Clinton	Constance DS	F4	19,121	19,121	14,250
Dublin	Dublin DS (via Seaforth TS)	F1 (Seaforth M2)	2,882	2,882	2,090
Embro	Ingersoll TS	M46	19,121	7,711	7,590
Goderich	Goderich TS	M3	2,850	1,040	2,835
Goderich	Goderich TS	M4	19,121	19,121	2,835
Goderich	Goderich TS	M5	19,121	2,835	2,835
Ingersoll	Ingersoll TS	M49	19,121	15,650	15,625
Ingersoll	Ingersoll TS	M50	19,121	10,925	15,640
Mitchell	Seaforth TS	M2	19,121	15,750	15,630
Norwich	Tillsonburg TS	M3	19,121	15,775	15,640
Otterville	Tillsonburg TS	M1	19,121	19,048	3,182
Otterville	Otterville DS (via Tillsonburg TS)	F1 (Tillsonburg M1)	19,121	19,091	1,800
Port Stanley	Edgeware TS	M3	19,121	19,111	18,650
Tavistock	Stratford TS	M7	2,882	2,882	2,850
Thamesford	Ingersoll TS	M45	19,121	19,095	10

REG/DER connections smaller than 10 kW follow the Hydro One Technical Interconnection Requirements (TIR), which limits generation to 7% of peak load on the feeder (or feeder segment). Constraints on REG/DERs <10 kW are shown in Table 13 below

Table 13: <10 kW Constraints

ERTH Power Corporation Micro Generation Capacity								
Service Territory	**Transformer Station**	**Feeder**	**DG % Limit**	**Allowable Generation 3Ph (kW)**	**Allowable Generation 1Ph (kW)**	**Available Generation Red (kW)**	**Available Generation White (kW)**	**Available Generation Blue (kW)**
Aylmer	Aylmer TS	M3	7%	366	122	119	119	102
Aylmer	Aylmer TS	M4	7%	611	204	201	201	183
Aylmer	Aylmer TS	M5	7%	599	200	200	200	200
Beachville	Ingersoll TS	M44	7%	70	23	4	6	13
Belmont	Buchanan TS	M21	7%	221	74	Constrained	Constrained	Constrained
Burgessville	Norwich North DS (supplied by Tillsonburg TS)	F2 (Tillsonburg M3)	7%	31	10	10	10	10
Clinton	Constance DS	F2	7%	225	75	Constrained	Constrained	Constrained
Clinton	Constance DS	F4	7%	214	71	71	71	71
Dublin	Dublin DS (supplied by Seaforth TS)	F1 (Seaforth M2)	7%	31	10	10	10	10
Embro	Ingersoll TS	M46	7%	80	27	0	Constrained	Constrained
Goderich	Goderich TS	M3	7%	550	183	Threshold Allocation available		
Goderich	Goderich TS	M4	7%	1,175	392	Threshold Allocation available		
Goderich	Goderich TS	M5	7%	593	198	Threshold Allocation available		
Ingersoll	Ingersoll TS	M49	7%	722	241	241	241	241
Ingersoll	Ingersoll TS	M50	7%	967	322	160	147	138
Ingersoll	Ingersoll TS	M51	7%	0	0	Not Applicable		
Ingersoll	Ingersoll TS	M52	7%	373	124	Not Applicable		
Mitchell	Seaforth TS	M2	7%	681	227	217	194	197
Norwich	Tillsonburg TS	M3	7%	291	97	84	84	94
Otterville	Tillsonburg TS Fleetwood	M1	7%	39	13	3	13	13
Otterville	Otterville DS (supplied by Tillsonburg TS)	F1 (Tillsonburg M1)	7%	80	27	27	27	27
Port Stanley	Edgeware TS	M3	7%	279	93	80	83	83
Tavistock	Stratford TS	M7	7%	522	174	62	81	35
Thamesford	Ingersoll TS	M45	7%	129	43	Threshold Allocation available		

Figure 27 is an extraction from the REG plan detailing the restricted feeders on the ERTH Power system.

Figure 27: DER Restricted Feeder List

DER CONNECTION PROCEDURES
RESTRICTED FEEDER LIST

Report Date: January 1, 2024 Next Release: January 1, 2025

Town	Station	Feeder	Voltage (kV)	Restricted
Aylmer	Aylmer TS	34M3	27.6/16	No
	AYL-MS1 (Forest)	AYL-1F1	4.16/2.4	No
	AYL-MS1 (Forest)	AYL-1F2	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F1	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F2	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F3	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F4	4.16/2.4	No
	Aylmer TS	34M4	27.6/16	No
	Aylmer TS	34M5	27.6/16	No
Beachville	Ingersoll TS	38M44	27.6/16	No
	BEA-MS1	BEA-1F1	4.16/2.4	No
Belmont	Buchanan TS	19M21	27.6/16	Yes
	Belmont DS	F1	8.32/4.8	Yes
Burgessville	Tillsonburg TS	20M3	27.6/16	No
	Norwich North DS	F2	8.32/4.8	No
Clinton	Constance DS	F2	27.6/16	No
	CLI-MS1	CLN-1F1	4.16/2.4	No
	CLI-MS1	CLN-1F2	4.16/2.4	No
	CLI-MS1	CLN-1F3	4.16/2.4	No
	Constance DS	F4	27.6/16	No
Dublin	Seaforth TS	61M2	27.6/16	No
	Dublin DS	F1	8.32/4.8	No
Embro	Ingersoll TS	38M46	27.6/16	No
Goderich	Goderich TS	31M3	27.6/16	No
	GDE-MS2	GDE-2F2	4.16/2.4	No
	GDE-MS2	GDE-2F3	4.16/2.4	No
	Goderich TS	31M4	27.6/16	No
	Goderich TS	31M5	27.6/16	No
	GDE-MS3	GDE-3F3	4.16/2.4	No
	GDE-MS3	GDE-3F4	4.16/2.4	No
	GDE-MS4	GDE-4F1	4.16/2.4	No
	GDE-MS4	GDE-4F3	4.16/2.4	No
Ingersoll	Ingersoll TS	38M49	27.6/16	No
	Ingersoll TS	38M50	27.6/16	No
	ING-MS1	ING-1F1	4.16/2.4	No
	ING-MS1	ING-1F2	4.16/2.4	No
	Ingersoll TS	38M51	27.6/16	No
	Ingersoll TS	38M52	27.6/16	No
Mitchell	Seaforth TS	61M2	27.6/16	No
	TX#1517	F1	4.16/2.4	No
Norwich	Tillsonburg TS	20M3	27.6/16	No
Otterville	Tillsonburg TS	20M1	27.6/16	No
	Otterville DS	F1	8.32/4.8	No
Port Stanley	Edgeware TS	27M3	27.6/16	Yes
	PTS-MS1	PTS-1F1	4.16/2.4	Yes
Tavistock	Stratford TS	68M7	27.6/16	No
	TAV-MS1	TAV-1F2	4.16/2.4	No
	TAV-MS1	TAV-1F3	4.16/2.4	No
Thamesford	Ingersoll TS	38M45	27.6/16	No

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Since the above constraints arise on a feeder level or at stations owned by Hydro One, ERTH Power is not expecting to incur costs relating to overcoming these constraints. Until upstream facilities are upgraded, ERTH Power is unable to connect REG/DERs to the constrained feeders.

ERTH Power is unable to forecast future REG/DER connections beyond those projects in the current queue. Queued projects comprise twelve (12) Micro-Net-metering projects totalling 105kW, seven (7) large Net-metering projects totalling 1,115 kW and three load displacement projects totalling 7,647 kW which are at various stages of approvals. Growth in REG/DER applications is expected however since the first constraint is usually the Hydro One connection, additional investment is not expected on the ERTH Power system.

5.3.5 CDM ACTIVITES TO ADDRESS SYSTEM NEEDS

ERTH Power has participated in CDM activities and has assisted customers with the implementation of 3rd party CDM programs that have activity reduced peak demand and contributed to provincial load reduction targets. CDM is currently administered by the IESO under the provincial CDM framework and since 2021 the distributor’s input to CDM has been limited in nature and intended not to duplicate IESO efforts.

ERTH Power will continue to support customer inquiries and efficiency initiative behind the meter and support the deployment of DERs for load displacement but is not planning on CDM to replace capital programs that are otherwise needed to support system operations.

ERTH Power engages with stakeholders on Conservation and Demand Management (CDM) initiatives to identify opportunities to reduce peak demand and defer traditional infrastructure investments. These engagements involve analyzing the potential for energy efficiency programs, demand response initiatives, and other CDM activities to address system needs. ERTH Power collaborates with the IESO, municipalities, and other partners to develop and implement CDM programs that align with regional and provincial energy conservation goals.

There are no projects in the ERTH Power service territory which are candidates for deferral by use of CDM initiatives

5.4 Capital Expenditure Plan

This section justifies the distributor's proposed expenditures on the distribution system and for general plant for the five-year planning period including investment and O&M activities. The investments described are driven by the reliability and service quality results of Section 5.2.3 and the Asset Overview of Section 5.3.2.

5.4.1 CAPITAL EXPENDITURE SUMMARY

The information under this section provides a snapshot of the distributor is five-year historical spend and five-year forecast spend. Historical spends are compared to the planned spend for each historical year and are broken out by the legacy ERTH Power region and the former Goderich (WCHE) area. In addition, average and total plans are compared to actuals.

As a result of the combination of the Goderich (WCHE) area with the previous ERTH Power area, there are many combinations of planned and actual expenses across year, areas and spending categories. The following tables present the most obvious views into the spending pattern however; some of the content is repeated in various sections.

5.4.1.1 Plan vs Actual Variances for the Historical Period

In order to create a baseline for the Goderich area which was not part of the previous DSP, the "plan" from the WCHE 2016 CoS are added to the IRM rate increases yearly to 2023. The2022 and 2023 values for "plan" for 2023 in the ERTH Power area have been extrapolated from the previous CoS using the IRM increases. Some pro-rating of costs between service areas was required to align the spending records.

The most significant variation from plan relates to unplanned growth in Residential Connection in the period of 2018 to 2022.

5.4.1.1.1 2018 Plan vs Actual - Historical Analysis

Table 14 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and

Table 14: Plan vs Actual 2018

		2018					
CATEGORY		ERTH Plan	WCHE Plan	Plan Total	Actual	Variance	%
System Access	Residential Connections	$231,000	$40,520	$271,520	$430,158	$158,638	158%
	C&I Connections	$204,000	$40,520	$244,520	$283,690	$39,170	116%
	Meter Management	$234,500	$12,663	$247,163	$172,527	-$74,636	70%
	Facility Relocations	$150,000	$15,195	$165,195	$244,013	$78,818	148%
	TOTAL	**$819,500**	**$108,898**	**$928,398**	**$1,130,388**	$201,990	**122%**
System Renewal	Fixed DX Asset Replacement	$2,074,450	$521,695	$2,596,145	$2,274,681	-$321,464	88%
	Substation Upgrades	$8,000	$20,260	$28,260	$34,900	$6,640	123%
	Maps & Records	$120,000	$0	$120,000	$87,403	-$32,597	73%
	TOTAL	**$2,202,450**	**$541,955**	**$2,744,405**	**$2,396,984**	-$347,421	**87%**
System Service	System Automation	$90,000	$0	$90,000	$58,179	-$31,821	65%
	Capacity Upgrades	$0	$0	$0	$125,046	$125,046	N/A
	TOTAL	**$90,000**	**$0**	**$90,000**	**$183,225**	$93,225	**204%**
General Plant	IT Hardware/Software	$56,000	$25,325	$81,325	$112,621	$31,296	138%
	Leasehold Improvements	$35,000	$10,130	$45,130	$96,396	$51,266	214%
	Tools & Equipment	$20,000	$10,130	$30,130	$44,008	$13,878	146%
	Fleet Sustainment	$20,000	$35,455	$55,455	$63,466	$8,011	114%
	TOTAL	**$131,000**	**$81,040**	**$212,040**	**$316,491**	$104,451	**149%**
	TOTAL CAPITAL SPEND	**$3,242,950**	**$731,893**	**$3,974,843**	**$4,027,088**	$52,245	**101%**

- **System Access:** $158k of the variance was due to increased spending above budget within residential connections. This was near the start of an uptick in housing starts in Ontario and we experienced higher than normal residential development activity.
- **System Renewal:** lower spend to account for increased System Access and a Capacity Upgrade (System Service) project at the Aylmer TS to maintain overall budget; multiple projects deferred.
- **System Service:** increased spend because of a new feeder installed to the Town of Aylmer. Hydro One rebuilt the Aylmer TS and ERTH Power had an opportunity to secure an additional feeder.
- **General Plant:** Additional $35k to replace the roof at MS1 in Ingersoll that was not budgeted.

Table 15 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2018.

Table 15: Plan vs Actual 2018 by Area

		ERTH 2018		
CATEGORY		ERTH Plan	ERTH Actual	%
System Access	Residential Connections	$231,000	$365,423	158%
	C&I Connections	$204,000	$218,955	107%
	Meter Management	$234,500	$145,459	62%
	Facility Relocations	$150,000	$244,013	163%
	TOTAL	**$819,500**	**$973,849**	**119%**
System Renewal	Fixed DX Asset Replacement	$2,074,450	$1,753,437	85%
	Substation Upgrades	$8,000	$34,900	436%
	Maps & Records	$120,000	$87,403	73%
	TOTAL	**$2,202,450**	**$1,875,740**	**85%**
System Service	System Automation	$90,000	$48,700	54%
	Aylmer TS Breaker	$0	$125,046	N/A
	TOTAL	**$90,000**	**$173,746**	**193%**
General Plant	IT Hardware/Software	$56,000	$112,621	201%
	Leasehold Improvements	$35,000	$89,921	257%
	Tools & Equipment	$20,000	$41,610	208%
	Fleet Sustainment	$20,000	$63,466	317%
	TOTAL	**$131,000**	**$307,617**	**235%**
	TOTAL CAPITAL SPEND	**$3,242,950**	**$3,330,953**	**103%**

		WCHE 2018		
CATEGORY		WCHE Plan	WCHE Actual	%
System Access	Residential Connections	$40,520	$64,735	160%
	C&I Connections	$40,520	$64,735	160%
	Meter Management	$12,663	$27,068	214%
	Facility Relocations	$15,195	$0	0%
	TOTAL	**$108,898**	**$156,538**	**144%**
System Renewal	Fixed DX Asset Replacement	$521,695	$521,244	100%
	Substation Upgrades	$20,260	$0	0%
	Maps & Records	$0	$0	N/A
	TOTAL	**$541,955**	**$521,244**	**96%**
System Service	System Automation	$0	$9,479	N/A
	-	-	-	-
	TOTAL	**$0**	**$9,479**	**N/A**
General Plant	IT Hardware/Software	$25,325	$0	0%
	Leasehold Improvements	$10,130	$6,475	64%
	Tools & Equipment	$10,130	$2,398	24%
	Fleet Sustainment	$35,455	$0	0%
	TOTAL	**$81,040**	**$8,873**	**11%**
	TOTAL CAPITAL SPEND	**$731,893**	**$696,134**	**95%**

- The comments explained above in the combined historical analysis remain valid, and any variations within the stand-alone WCHE spend are not material.

5.4.1.1.2 2019 Plan vs Actual - Historical Analysis

Table 16 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2019.

Table 16: Plan vs Actual 2019

		2019					
CATEGORY		ERTH Plan	WCHE Plan	Plan Total	Actual	Variance	%
System Access	Residential Connections	$231,000	$40,763	$271,763	$719,469	$447,706	265%
	C&I Connections	$204,000	$40,763	$244,763	$148,171	-$96,592	61%
	Meter Management	$275,100	$12,738	$287,838	$203,982	-$83,856	71%
	Facility Relocations	$150,000	$15,286	$165,286	$258,195	$92,909	156%
	TOTAL	**$860,100**	**$109,551**	**$969,651**	**$1,329,817**	$360,166	**137%**
System Renewal	Fixed DX Asset Replacement	$1,915,730	$524,825	$2,440,555	$2,588,287	$147,732	106%
	Substation Upgrades	$26,500	$20,382	$46,882	$93,311	$46,429	199%
	Maps & Records	$120,000	$0	$120,000	$123,362	$3,362	103%
	TOTAL	**$2,062,230**	**$545,207**	**$2,607,437**	**$2,804,960**	$197,523	**108%**
System Service	System Automation	$90,000	$0	$90,000	$26,011	-$63,989	29%
	TOTAL	**$90,000**	**$0**	**$90,000**	**$26,011**	-$63,989	**29%**
General Plant	IT Hardware/Software	$59,750	$25,477	$85,227	$34,983	-$50,244	41%
	Leasehold Improvements	$35,000	$10,191	$45,191	$33,722	-$11,469	75%
	Tools & Equipment	$35,000	$10,191	$45,191	$25,363	-$19,828	56%
	Fleet Sustainment	$90,000	$35,668	$125,668	$107,147	-$18,521	85%
	TOTAL	**$219,750**	**$81,526**	**$301,276**	**$201,215**	-$100,061	**67%**
	TOTAL CAPITAL SPEND	**$3,232,080**	**$736,284**	**$3,968,364**	**$4,362,003**	$393,639	**110%**

- **System Access:** $335k of the variance was due to increased spending above budget within residential connections. C&I Connections were less than planned, and facility relocation requests were higher than planned. All three (3) items are customer/municipality driven and can create variances from plan.
- **System Renewal:** no material change from plan

- **System Service:** minor non-material projects deferred or cancelled within IT budget and system automation
- **General Plant:** some efficiencies gained within the WCHE merger; we had duplicate fleet and tools and therefore spending in General Plant was less.

Table 17 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2019.

Table 17: Plan vs Actual 2019 by Area

CATEGORY		ERTH 2019 ERTH Plan	ERTH Actual	%
System Access	Residential Connections	$231,000	$611,549	265%
	C&I Connections	$204,000	$125,945	62%
	Meter Management	$275,100	$173,385	63%
	Facility Relocations	$150,000	$219,466	146%
	TOTAL	**$860,100**	**$1,130,344**	**131%**
System Renewal	Fixed DX Asset Replacement	$1,915,730	$2,150,973	112%
	Substation Upgrades	$26,500	$79,314	299%
	Maps & Records	$120,000	$104,858	87%
	TOTAL	**$2,062,230**	**$2,335,145**	**113%**
System Service	System Automation	$90,000	$22,109	25%
	TOTAL	**$90,000**	**$22,109**	**25%**
General Plant	IT Hardware/Software	$59,750	$29,736	50%
	Leasehold Improvements	$35,000	$33,722	96%
	Tools & Equipment	$35,000	$21,559	62%
	Fleet Sustainment	$90,000	$91,075	101%
	TOTAL	**$219,750**	**$176,091**	**80%**
	TOTAL CAPITAL SPEND	**$3,232,080**	**$3,663,689**	**113%**

CATEGORY		WCHE 2019 WCHE Plan	WCHE Actual	%
System Access	Residential Connections	$40,763	$107,920	265%
	C&I Connections	$40,763	$22,226	55%
	Meter Management	$12,738	$30,597	240%
	Facility Relocations	$15,286	$38,729	253%
	TOTAL	**$109,551**	**$199,473**	**182%**
System Renewal	Fixed DX Asset Replacement	$524,825	$437,315	83%
	Substation Upgrades	$20,382	$13,997	69%
	Maps & Records	$0	$18,504	N/A
	TOTAL	**$545,207**	**$469,815**	**86%**
System Service	System Automation	$0	$3,902	N/A
	TOTAL	**$0**	**$3,902**	**N/A**
General Plant	IT Hardware/Software	$25,477	$5,247	21%
	Leasehold Improvements	$10,191	$33,722	331%
	Tools & Equipment	$10,191	$3,804	37%
	Fleet Sustainment	$35,668	$16,072	45%
	TOTAL	**$81,526**	**$58,846**	**72%**
	TOTAL CAPITAL SPEND	**$736,284**	**$732,036**	**99%**

- The comments explained above in the combined historical analysis remain valid, and any variations within the stand-alone WCHE spend are not material.

5.4.1.1.3 2020 Plan vs Actual - Historical Analysis

Table 18 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2020.

Table 18: Plan vs Actual 2020

		2020					
CATEGORY		ERTH Plan	WCHE Plan	Plan Total	Actual	Variance	%
System Access	**Residential Connections**	$231,000	$41,130	$272,130	$695,454	$423,324	256%
	C&I Connections	$204,000	$41,130	$245,130	$102,603	-$142,527	42%
	Meter Management	$167,700	$12,853	$180,553	$187,291	$6,738	104%
	Facility Relocations	$150,000	$15,424	$165,424	$38,264	-$127,160	23%
	TOTAL	**$752,700**	**$110,537**	**$863,237**	**$1,023,612**	$160,375	**119%**
System Renewal	**Fixed DX Asset Replacement**	$1,839,040	$529,549	$2,368,589	$2,692,631	$324,042	114%
	Substation Upgrades	$8,000	$20,565	$28,565	$10,609	-$17,956	37%
	Maps & Records	$120,000	$0	$120,000	$99,284	-$20,716	83%
	TOTAL	**$1,967,040**	**$550,114**	**$2,517,154**	**$2,802,524**	$285,370	**111%**
System Service	**System Automation**	$55,000	$0	$55,000	$0	-$55,000	0%
	TOTAL	**$55,000**	**$0**	**$55,000**	**$0**	-$55,000	**0%**
General Plant	**IT Hardware/Software**	$98,500	$25,706	$124,206	$49,150	-$75,056	40%
	Leasehold Improvements	$80,000	$10,282	$90,282	$50,037	-$40,245	55%
	Tools & Equipment	$20,000	$10,282	$30,282	$33,895	$3,613	112%
	Fleet Sustainment	$275,000	$35,989	$310,989	$288,850	-$22,139	93%
	TOTAL	**$473,500**	**$82,260**	**$555,760**	**$421,932**	-$133,828	**76%**
	TOTAL CAPITAL SPEND	**$3,248,240**	**$742,910**	**$3,991,150**	**$4,248,068**	$256,918	**106%**

- **System Access:** $278k of variance was due to increased spending above budget within residential connections. C&I Connections were less than planned along with facility relocations; all three (3) items are customer/municipality driven and can create variances from plan.
- **System Renewal:** we had a few projects that went over budget, primarily an overhead conversion project in Clinton on Ontario & William St.; this accounted for $212k of the variance.
- **System Service:** no system automation projects were optimized within the 2020 budget.
- **General Plant:** Large 42' Bucket Truck in budget was delayed due to COVID/Supply Chain and not received in 2020 as originally planned.

Table 19 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2020.

Table 19: Plan vs Actual 2020 by Area

		ERTH 2020		
CATEGORY		ERTH Plan	ERTH Actual	%
System Access	Residential Connections	$231,000	$591,136	256%
	C&I Connections	$204,000	$87,213	43%
	Meter Management	$167,700	$159,197	95%
	Facility Relocations	$150,000	$32,524	22%
	TOTAL	**$752,700**	**$870,070**	**116%**
System Renewal	Fixed DX Asset Replacement	$1,839,040	$2,588,241	141%
	Substation Upgrades	$8,000	$9,018	113%
	Maps & Records	$120,000	$84,391	70%
	TOTAL	**$1,967,040**	**$2,681,650**	**136%**
System Service	System Automation	$55,000	$0	0%
	TOTAL	**$55,000**	**$0**	**0%**
General Plant	IT Hardware/Software	$98,500	$41,778	42%
	Leasehold Improvements	$80,000	$38,937	49%
	Tools & Equipment	$20,000	$28,811	144%
	Fleet Sustainment	$275,000	$288,850	105%
	TOTAL	**$473,500**	**$398,375**	**84%**
	TOTAL CAPITAL SPEND	**$3,248,240**	**$3,950,095**	**122%**

		WCHE 2020		
CATEGORY		WCHE Plan	WCHE Actual	%
System Access	Residential Connections	$41,130	$104,318	254%
	C&I Connections	$41,130	$15,390	37%
	Meter Management	$12,853	$28,094	219%
	Facility Relocations	$15,424	$5,740	37%
	TOTAL	**$110,537**	**$153,542**	**139%**
System Renewal	Fixed DX Asset Replacement	$529,549	$97,668	18%
	Substation Upgrades	$20,565	$1,591	8%
	Maps & Records	$0	$14,893	N/A
	TOTAL	**$550,114**	**$114,152**	**21%**
System Service	System Automation	$0	$0	N/A
	TOTAL	**$0**	**$0**	**N/A**
General Plant	IT Hardware/Software	$25,706	$7,373	29%
	Leasehold Improvements	$10,282	$11,100	108%
	Tools & Equipment	$10,282	$5,084	49%
	Fleet Sustainment	$35,989	$0	0%
	TOTAL	**$82,260**	**$23,557**	**29%**
	TOTAL CAPITAL SPEND	**$742,910**	**$291,250**	**39%**

- No large System Renewal projects were completed in the Town of Goderich; this accounts for the majority of variances for both ERTH Power and WCHE in 2020.

5.4.1.1.4 2021 Plan vs Actual - Historical Analysis

Table 20 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2021.

Table 20: Plan vs Actual 2021

		2021					
CATEGORY		ERTH Plan	WCHE Plan	Plan Total	Actual	Variance	%
System Access	Residential Connections	$231,000	$41,706	$272,706	$582,240	$309,534	214%
	C&I Connections	$204,000	$41,706	$245,706	$112,921	-$132,785	46%
	Meter Management	$171,300	$13,033	$184,333	$453,318	$268,985	246%
	Facility Relocations	$150,000	$15,640	$165,640	$88,235	-$77,405	53%
	TOTAL	**$756,300**	**$112,084**	**$868,384**	**$1,236,714**	$368,330	**142%**
System Renewal	Fixed DX Asset Replacement	$2,100,881	$536,962	$2,637,843	$2,540,938	-$96,905	96%
	Substation Upgrades	$8,000	$20,853	$28,853	$10,705	-$18,148	37%
	Maps & Records	$120,000	$0	$120,000	$82,606	-$37,394	69%
	TOTAL	**$2,228,881**	**$557,815**	**$2,786,696**	**$2,634,249**	-$152,447	**95%**
System Service	System Automation	$55,000	$0	$55,000	$6,108	-$48,892	11%
	TOTAL	**$55,000**	**$0**	**$55,000**	**$6,108**	-$48,892	**11%**
General Plant	IT Hardware/Software	$56,800	$26,066	$82,866	$85,160	$2,294	103%
	Leasehold Improvements	$42,500	$10,426	$52,926	$67,178	$14,252	127%
	Tools & Equipment	$35,000	$10,426	$45,426	$36,393	-$9,033	80%
	Fleet Sustainment	$90,000	$36,493	$126,493	$266,957	$140,464	211%
	TOTAL	**$224,300**	**$83,412**	**$307,712**	**$455,688**	$147,976	**148%**
	TOTAL CAPITAL SPEND	**$3,264,481**	**$753,311**	**$4,017,792**	**$4,332,759**	$314,967	**108%**

- **System Access:** $194k of variance was due to increased spending above budget within residential connections. Increased spending in Meter Management was a result of two (2) Wholesale Metering Points requiring after-hours replacement after an inspection deemed them end-of-life. ($125k) In addition, two

(2) orders of meters were received in 2021 because of supply chain uncertainty and we planned for one (1). (approx. $75k)

- **System Renewal:** no material change from plan
- **System Service:** only minor projects completed; no system automation projects completed in 2021.
- **General Plant:** increased costs on fleet vehicles accounts for majority of the variance.

Table 21 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2021.

Table 21: Plan vs Actual 2021 by Area

CATEGORY		ERTH 2021 ERTH Plan	ERTH Actual	%
System Access	Residential Connections	$231,000	$494,904	214%
	C&I Connections	$204,000	$95,983	47%
	Meter Management	$171,300	$385,320	225%
	Facility Relocations	$150,000	$75,000	50%
	TOTAL	**$756,300**	**$1,051,207**	**139%**
System Renewal	Fixed DX Asset Replacement	$2,100,881	$2,397,400	114%
	Substation Upgrades	$8,000	$9,099	114%
	Maps & Records	$120,000	$70,215	59%
	TOTAL	**$2,228,881**	**$2,476,714**	**111%**
System Service	System Automation	$55,000	$5,192	9%
	TOTAL	**$55,000**	**$5,192**	**9%**
General Plant	IT Hardware/Software	$56,800	$72,386	127%
	Leasehold Improvements	$42,500	$67,178	158%
	Tools & Equipment	$35,000	$30,934	88%
	Fleet Sustainment	$90,000	$63,000	70%
	TOTAL	**$224,300**	**$233,498**	**104%**
	TOTAL CAPITAL SPEND	**$3,264,481**	**$3,766,611**	**115%**

CATEGORY		WCHE 2021 WCHE Plan	WCHE Actual	%
System Access	Residential Connections	$41,706	$87,336	209%
	C&I Connections	$41,706	$16,938	41%
	Meter Management	$13,033	$67,998	522%
	Facility Relocations	$15,640	$13,235	85%
	TOTAL	**$112,084**	**$185,507**	**166%**
System Renewal	Fixed DX Asset Replacement	$536,962	$143,538	27%
	Substation Upgrades	$20,853	$1,606	8%
	Maps & Records	$0	$12,391	N/A
	TOTAL	**$557,815**	**$157,534**	**28%**
System Service	System Automation	$0	$916	N/A
	TOTAL	**$0**	**$916**	**N/A**
General Plant	IT Hardware/Software	$26,066	$12,774	49%
	Leasehold Improvements	$10,426	$0	0%
	Tools & Equipment	$10,426	$5,459	52%
	Fleet Sustainment	$36,493	$203,957	559%
	TOTAL	**$83,412**	**$222,190**	**266%**
	TOTAL CAPITAL SPEND	**$753,311**	**$566,148**	**75%**

5.4.1.1.5 2022 Plan vs Actual - Historical Analysis

Table 22 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2022.

Table 22: Plan vs Actual 2022

		2022					
CATEGORY		ERTH Plan	WCHE Plan	Plan Total	Actual	Variance	%
System Access	**Residential Connections**	$231,000	$42,373	$273,373	$1,023,784	$750,411	375%
	C&I Connections	$204,000	$42,373	$246,373	$197,554	-$48,819	80%
	Meter Management	$174,900	$13,242	$188,142	$220,494	$32,352	117%
	Facility Relocations	$150,000	$15,890	$165,890	$7,014	-$158,876	4%
	TOTAL	**$759,900**	**$113,878**	**$873,778**	**$1,448,846**	$575,068	**166%**
System Renewal	**Fixed DX Asset Replacement**	$1,811,454	$545,554	$2,357,008	$2,396,658	$39,650	102%
	Substation Upgrades	$8,000	$21,187	$29,187	$44,818	$15,631	154%
	Maps & Records	$120,000	$0	$120,000	$108,207	-$11,793	90%
	TOTAL	**$1,939,454**	**$566,740**	**$2,506,194**	**$2,549,683**	$43,489	**102%**
System Service	**System Automation**	$55,000	$0	$55,000	$114,378	$59,378	208%
	TOTAL	**$55,000**	**$0**	**$55,000**	**$114,378**	$59,378	**208%**
General Plant	**IT Hardware/Software**	$48,950	$26,483	$75,433	$92,683	$17,250	123%
	Leasehold Improvements	$42,500	$10,593	$53,093	$52,847	-$246	100%
	Tools & Equipment	$35,000	$10,593	$45,593	$58,784	$13,191	129%
	Fleet Sustainment	$400,000	$37,076	$437,076	$455,932	$18,856	104%
	TOTAL	**$526,450**	**$84,746**	**$611,196**	**$660,246**	$49,050	**108%**
	TOTAL CAPITAL SPEND	**$3,280,804**	**$765,364**	**$4,046,168**	**$4,773,153**	$726,985	**118%**

- **System Access:** In 2022, we paid an unexpectedly high number of developer paybacks, because of increased connections the year(s) previous; this totaled $673k for the year and accounts for the majority of the variance. The year also saw less facility relocation requests that normal.
- **System Renewal:** no material changes from plan
- **System Service:** Two (2) new automated switches were purchased and installed.
- **General Plant:** no material changes from plan

Table 23 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2022.

Table 23: Plan vs Actual 2022 by Area

		ERTH 2022		
CATEGORY		ERTH Plan	ERTH Actual	%
System Access	Residential Connections	$231,000	$870,216	377%
	C&I Connections	$204,000	$167,921	82%
	Meter Management	$174,900	$187,420	107%
	Facility Relocations	$150,000	$5,962	4%
	TOTAL	**$759,900**	**$1,231,519**	**162%**
System Renewal	Fixed DX Asset Replacement	$1,811,454	$2,007,097	111%
	Substation Upgrades	$8,000	$0	0%
	Maps & Records	$120,000	$91,976	77%
	TOTAL	**$1,939,454**	**$2,099,073**	**108%**
System Service	System Automation	$55,000	$97,221	177%
	TOTAL	**$55,000**	**$97,221**	**177%**
General Plant	IT Hardware/Software	$48,950	$78,781	161%
	Leasehold Improvements	$42,500	$45,351	107%
	Tools & Equipment	$35,000	$49,966	143%
	Fleet Sustainment	$400,000	$180,932	45%
	TOTAL	**$526,450**	**$355,030**	**67%**
	TOTAL CAPITAL SPEND	**$3,280,804**	**$3,782,843**	**115%**

		WCHE 2022		
CATEGORY		WCHE Plan	WCHE Actual	%
System Access	Residential Connections	$42,373	$153,568	362%
	C&I Connections	$42,373	$29,633	70%
	Meter Management	$13,242	$33,074	250%
	Facility Relocations	$15,890	$1,052	7%
	TOTAL	**$113,878**	**$217,327**	**191%**
System Renewal	Fixed DX Asset Replacement	$545,554	$389,561	71%
	Substation Upgrades	$21,187	$44,818	212%
	Maps & Records	$0	$16,231	N/A
	TOTAL	**$566,740**	**$450,610**	**80%**
System Service	System Automation	$0	$17,157	N/A
	TOTAL	**$0**	**$17,157**	**N/A**
General Plant	IT Hardware/Software	$26,483	$13,902	52%
	Leasehold Improvements	$10,593	$7,496	71%
	Tools & Equipment	$10,593	$8,818	83%
	Fleet Sustainment	$37,076	$275,000	742%
	TOTAL	**$84,746**	**$305,216**	**360%**
	TOTAL CAPITAL SPEND	**$765,364**	**$990,309**	**129%**

5.4.1.1.6 2023 Plan vs Actual - Historical Analysis

Table 24 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2023.

Table 24: Plan vs Actual 2023

		2023 (BEYOND CoS PLAN)					
CATEGORY		ERTH Plan	WCHE Plan	Plan Total	Actual	Variance	%
System Access	Residential Connections	$238,392	$43,517	$281,909	$130,386	-$151,523	46%
	C&I Connections	$210,528	$43,517	$254,045	$218,532	-$35,513	86%
	Meter Management	$180,497	$13,599	$194,096	$216,502	$22,406	112%
	Facility Relocations	$154,800	$16,319	$171,119	$393,802	$222,683	230%
	TOTAL	**$784,217**	**$116,952**	**$901,169**	**$959,222**	$58,053	**106%**
System Renewal	Fixed DX Asset Replacement	$1,869,421	$560,284	$2,429,704	$2,656,248	$226,544	109%
	Substation Upgrades	$8,256	$21,759	$30,015	$18,694	-$11,321	62%
	Maps & Records	$123,840	$0	$123,840	$103,889	-$19,951	84%
	TOTAL	**$2,001,517**	**$582,042**	**$2,583,559**	**$2,778,831**	$195,272	**108%**
System Service	System Automation	$56,760	$0	$56,760	$95,720	$38,960	169%
	TOTAL	**$56,760**	**$0**	**$56,760**	**$95,720**	$38,960	**169%**
General Plant	IT Hardware/Software	$50,516	$27,198	$77,715	$33,669	-$44,046	43%
	Leasehold Improvements	$43,860	$10,879	$54,739	$22,911	-$31,828	42%
	Tools & Equipment	$36,120	$10,879	$46,999	$54,920	$7,921	117%
	Fleet Sustainment	$412,800	$38,078	$450,878	$340,431	-$110,447	76%
	TOTAL	**$543,296**	**$87,034**	**$630,331**	**$451,931**	-$178,400	**72%**
	TOTAL CAPITAL SPEND	**$3,385,790**	**$786,029**	**$4,171,819**	**$4,285,704**	$113,885	**103%**

- **System Access:** Residential connections slowed into 2023 accounting for $150k variance, however we had an increase in facility relocation requests including an unplanned relocation on Carroll St. in Ingersoll accounting for $264k of costs.
- **System Renewal:** The increased spend on Fixed Distribution Asset replacement is primarily a result of a 2022 underground conversion project on Brimicomb St. in Goderich being delayed into the early part of

2023, along with some increased directional boring costs. That, along with two large three phase transformer failures costing approx. $43k and $48k on North Harbour Rd. in Goderich and Underwood Rd. in Ingersoll.

- **System Service:** Two (2) new automated switches were purchased and are planned to be installed in 2024.
- **General Plant:** Multiple small investments were deferred to the Ingersoll Bell St. location, along with two IT system upgrades. An RBD truck was expected to be received in 2023 and wasn't received until 2024.

Table 25 below details the comparison of planned capital expenses with actual spends detailed for the ERTH Power territory and Goderich (WCHE) for the year 2023.

Table 25: Plan vs Actual 2023 by Area

		ERTH 2023		
CATEGORY		ERTH Plan	ERTH Actual	%
System Access	Residential Connections	$238,392	$110,828	46%
	C&I Connections	$210,528	$185,752	88%
	Meter Management	$180,497	$184,027	102%
	Facility Relocations	$154,800	$374,448	242%
	TOTAL	**$784,217**	**$855,055**	**109%**
System Renewal	Fixed DX Asset Replacement	$1,869,421	$1,981,609	106%
	Substation Upgrades	$8,256	$15,890	192%
	Maps & Records	$123,840	$88,306	71%
	TOTAL	**$2,001,517**	**$2,085,805**	**104%**
System Service	System Automation	$56,760	$81,362	143%
	TOTAL	**$56,760**	**$81,362**	**143%**
General Plant	IT Hardware/Software	$50,516	$28,619	57%
	Leasehold Improvements	$43,860	$15,711	36%
	Tools & Equipment	$36,120	$46,682	129%
	Fleet Sustainment	$412,800	$320,431	78%
	TOTAL	**$543,296**	**$411,443**	**76%**
	TOTAL CAPITAL SPEND	**$3,385,790**	**$3,433,664**	**101%**

		WCHE 2023		
CATEGORY		WCHE Plan	WCHE Actual	%
System Access	Residential Connections	$43,517	$19,558	45%
	C&I Connections	$43,517	$32,780	75%
	Meter Management	$13,599	$32,475	239%
	Facility Relocations	$16,319	$19,354	119%
	TOTAL	**$116,952**	**$104,167**	**89%**
System Renewal	Fixed DX Asset Replacement	$560,284	$674,639	120%
	Substation Upgrades	$21,759	$2,804	13%
	Maps & Records	$0	$15,583	N/A
	TOTAL	**$582,042**	**$693,026**	**119%**
System Service	System Automation	$0	$14,358	N/A
	TOTAL	**$0**	**$14,358**	**N/A**
General Plant	IT Hardware/Software	$27,198	$5,050	19%
	Leasehold Improvements	$10,879	$7,200	66%
	Tools & Equipment	$10,879	$8,238	76%
	Fleet Sustainment	$38,078	$20,000	53%
	TOTAL	**$87,034**	**$40,488**	**47%**
	TOTAL CAPITAL SPEND	**$786,029**	**$852,039**	**108%**

5.4.1.1.7 Plan vs. Actual - Historical Average

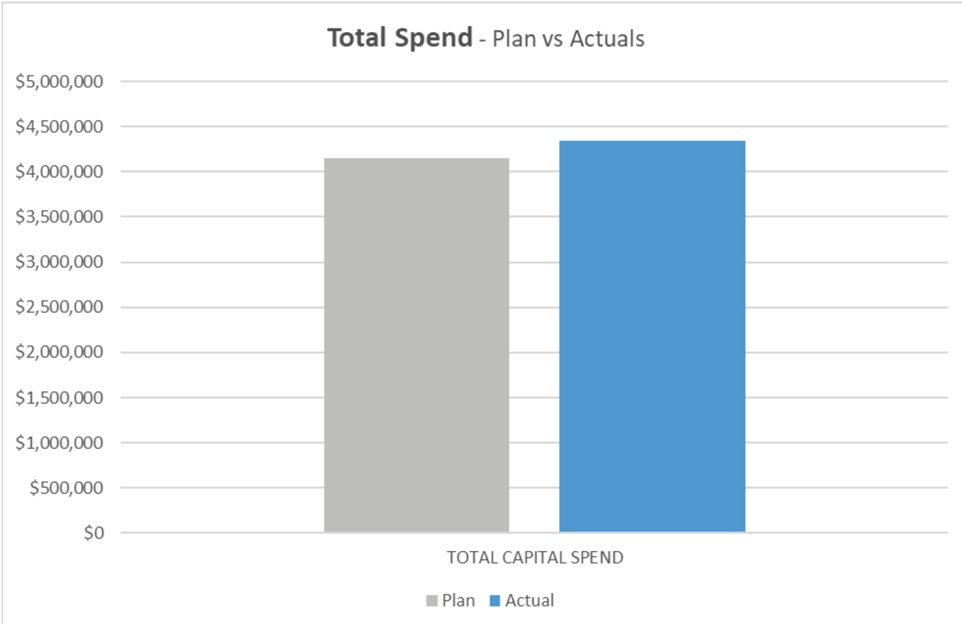
Table 26 below details the comparison of planned capital expenses with actual spends detailed for the merged ERTH Power territory averaged over the period from 2018-2023.

Table 26: Plan vs Actual Average 2018-2023: Merged

CATEGORY		ERTH (Merged) Plan AVERAGE Plan	Actual	%
System Access	Residential Connections	$300,835	$596,915	198%
	C&I Connections	$236,668	$177,245	75%
	Meter Management	$227,430	$242,352	107%
	Facility Relocations	$154,792	$171,587	111%
	TOTAL	**$919,725**	**$1,188,100**	**129%**
System Renewal	Fixed DX Asset Replacement	$2,541,737	$2,524,907	99%
	Substation Upgrades	$50,584	$35,506	70%
	Maps & Records	$112,500	$100,792	90%
	TOTAL	**$2,704,821**	**$2,661,205**	**98%**
System Service	System Automation	$76,667	$50,066	65%
	Capacity Upgrades	$0	$20,841	N/A
	TOTAL	**$76,667**	**$70,907**	**92%**
General Plant	IT Hardware/Software	$88,855	$68,044	77%
	Leasehold Improvements	$56,667	$53,849	95%
	Tools & Equipment	$43,750	$42,227	97%
	Fleet Sustainment	$265,960	$253,797	95%
	TOTAL	**$455,232**	**$417,917**	**92%**
	TOTAL CAPITAL SPEND	**$4,156,445**	**$4,338,129**	**104%**

Figure 28 below details the comparison of planned capital expenses with actual average spends detailed for the merged ERTH Power territory totaled over the period from 2018-2023.

Figure 28: Plan vs Actual Average 2018-2023: Merged

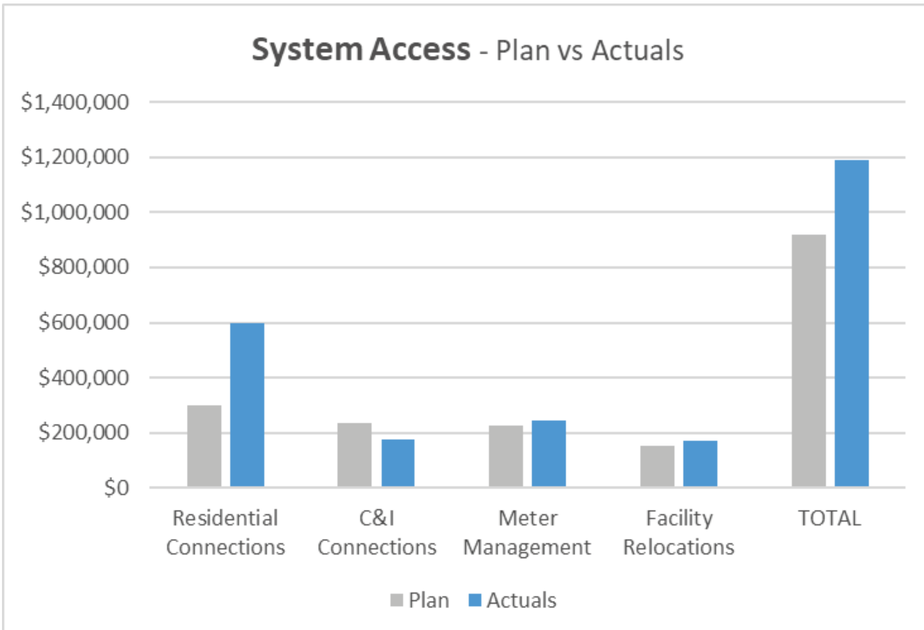


- **Total Spend:** from an overall perspective, the Total Capital Spend vs. Plan was managed well and within 4%. The primary driver of this increase throughout the historical period was an increase in residential connections. In the absence of System Access spending which is largely uncontrollable, the capital spend was managed within 1% of Plan.

5.4.1.1.8 Plan vs Actuals by Capital Investment Category

Table 29 below details the comparison of total planned capital expenses with actual spends by spending category for System Access projects totaled over the period from 2018-2023.

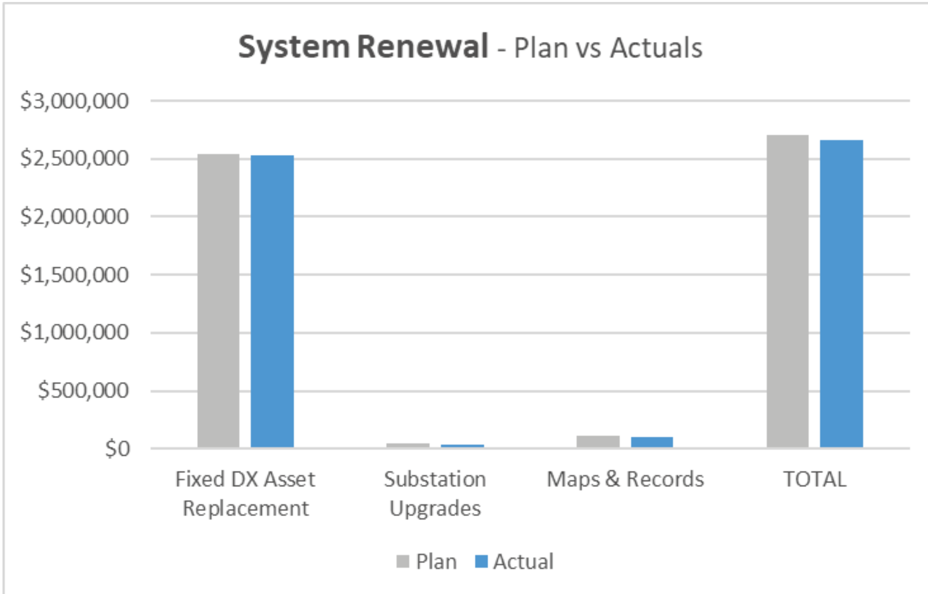
Figure 29: Plan vs Actual Average 2018-2023: System Access



System Access: as noted above, the vast majority of System Access spending is driven by customer connections, facility relocation requests and meter failures; all of which are largely uncontrollable and can be difficult to predict. Residential Connections over the historical years increased drastically compared to plan and accounts for almost all of the 29% variance within the category.

Table 30 below details the comparison of total planned capital expenses with actual spends by spending category for System Renewal projects totaled over the period from 2018-2023.

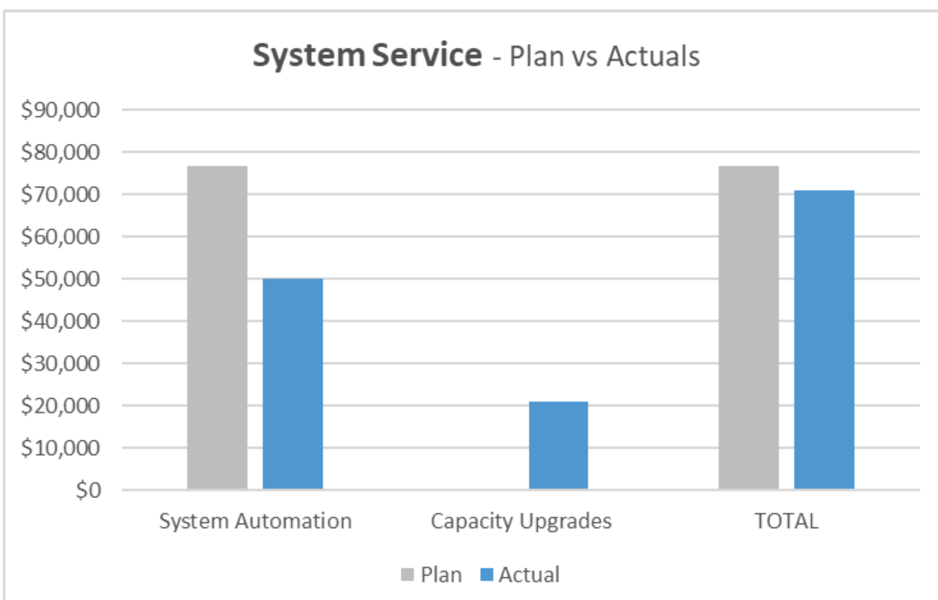
Figure 30: Plan vs Actual Average 2018-2023: System Renewal



System Renewal: System Renewal spending was managed to within 2% of the plan over the historical period. That being said, inflationary factors within the supply chain have affected the actual number of assets being replaced per dollar of spend and this will be a factor moving forward.

Table 31 below details the comparison of total planned capital expenses with actual spends by spending category for System Service projects totaled over the period from 2018-2023.

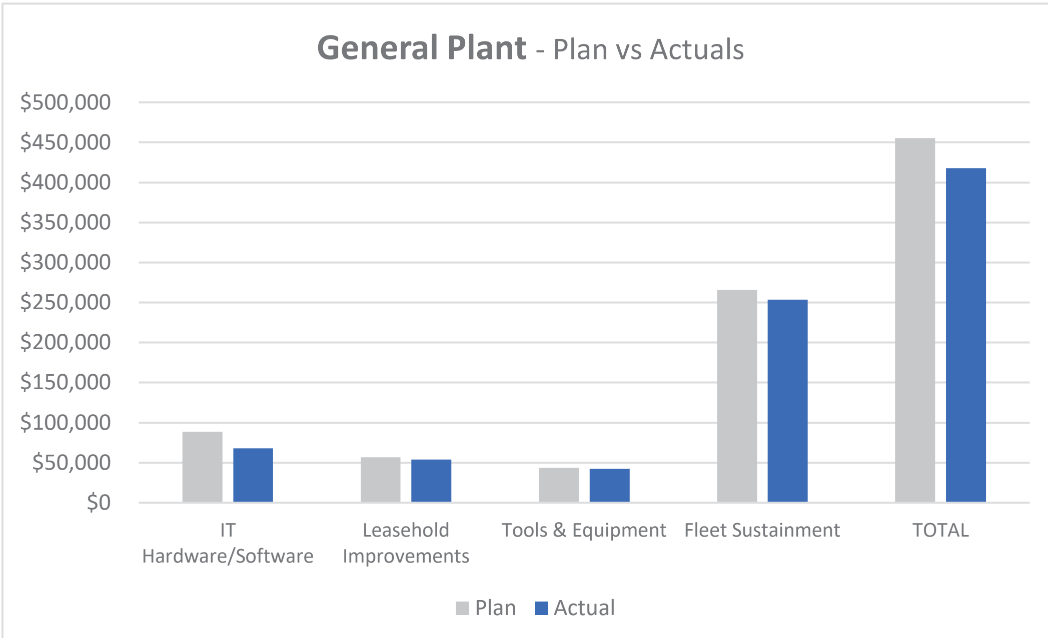
Figure 31: Plan vs Actual Average 2018-2023: System Service



System Access: In general, System Access spending is aligned with the plan over the historical period. Due to small value of the category, the % spend each year is high or low, but averages out over the time frame.

Figure 32 below details the comparison of total planned capital expenses with actual spends by spending category for General Service projects totaled over the period from 2018-2023.

Figure 32: Plan vs Actual Average 2018-2023: General Service



General Plant: Again, the General Plant category has remained aligned with the values set out in our plan. IT Software/Hardware upgrades proceeded slower than expected as the work environment changes and plans shift, however these affects are minor. Fleet Sustainment was less than plan however this is due to delays in large vehicles ordered; at the time of plan a large vehicle could be ordered and received in 1-2 years and now has extended to 3+ years.

5.4.1.1.9 Plan vs. Actual - Historical Average (ERTH Power Main vs WCHE)

Table 27 below details the comparison of planned capital expenses with actual spends detailed by spending category for the legacy ERTH Power area vs the WCHE area and totaled over the period from 2018-2023.

Table 27: Plan vs Actual Total 2018-2023: by Area

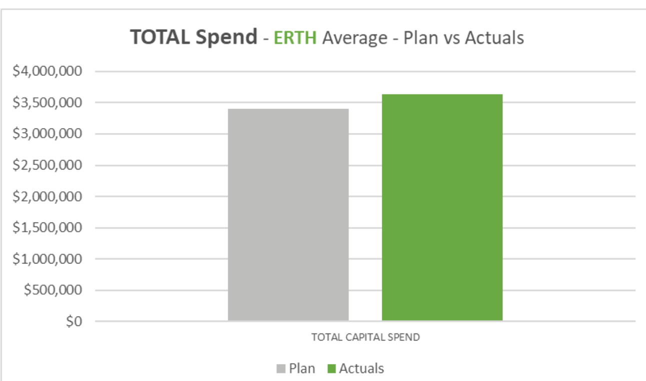
CATEGORY		ERTH Plan	ERTH Actual	%
		ERTH Plan AVERAGE		
System Access	Residential Connections	$259,167	$507,343	196%
	C&I Connections	$195,000	$146,962	75%
	Meter Management	$214,408	$205,801	96%
	Facility Relocations	$139,167	$158,569	114%
	TOTAL	**$807,742**	**$1,018,674**	**126%**
System Renewal	Fixed DX Asset Replacement	$2,005,259	$2,146,459	107%
	Substation Upgrades	$29,750	$24,704	83%
	Maps & Records	$112,500	$87,858	78%
	TOTAL	**$2,147,509**	**$2,259,021**	**105%**
System Service	System Automation	$76,667	$42,431	55%
	TOTAL	**$76,667**	**$42,431**	**55%**
General Plant	IT Hardware/Software	$62,813	$60,653	97%
	Leasehold Improvements	$46,250	$48,470	105%
	Tools & Equipment	$33,333	$36,594	110%
	Fleet Sustainment	$229,500	$167,959	73%
	TOTAL	**$371,896**	**$313,676**	**84%**
	TOTAL CAPITAL SPEND	**$3,403,813**	**$3,633,802**	**107%**

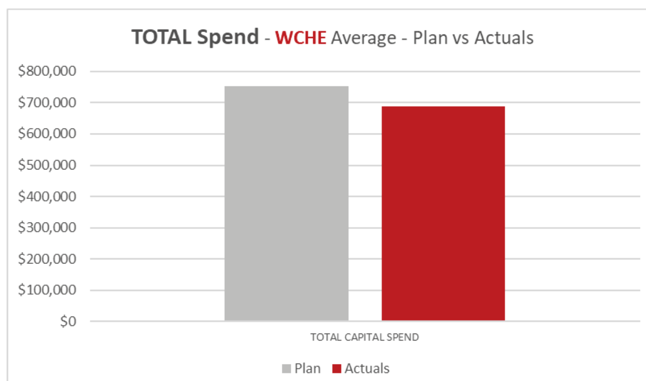
CATEGORY		WCHE Plan	WCHE Actual	%
		WCHE Plan AVERAGE		
System Access	Residential Connections	$41,668	$89,573	215%
	C&I Connections	$41,668	$30,284	73%
	Meter Management	$13,021	$36,551	281%
	Facility Relocations	$15,626	$13,018	83%
	TOTAL	**$111,983**	**$169,425**	**151%**
System Renewal	Fixed DX Asset Replacement	$536,478	$377,327	70%
	Substation Upgrades	$20,834	$10,803	52%
	Maps & Records	$0	$12,934	N/A
	TOTAL	**$557,312**	**$401,064**	**72%**
System Service	System Automation	$0	$7,635	N/A
	TOTAL	**$0**	**$7,635**	**N/A**
General Plant	IT Hardware/Software	$26,043	$7,391	28%
	Leasehold Improvements	$10,417	$10,999	106%
	Tools & Equipment	$10,417	$5,633	54%
	Fleet Sustainment	$36,460	$85,838	235%
	TOTAL	**$83,336**	**$109,862**	**132%**
	TOTAL CAPITAL SPEND	**$752,632**	**$687,986**	**91%**

5.4.1.1.10 Plan vs. Actual - Historical Total (ERTH Power Main vs WCHE)

Figure 33 below details the comparison of total planned capital expenses with actual spends for the legacy ERTH Power area vs the WCHE area and totaled over the period from 2018-2023.

Figure 33: Plan vs Actual Total 2018-2023: by Area

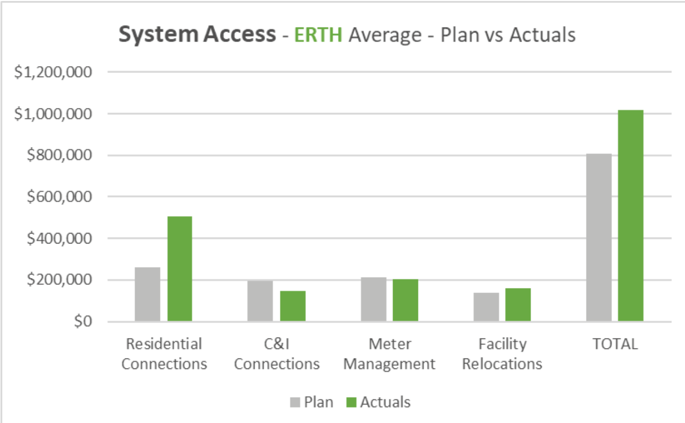




Total Spend: from an overall perspective, the Total Capital Spend along with spending in the four categories has been managed between the ERTH Power Main rate zone and the WCHE rate zone. In general, the major variance is increased System Renewal spend in ERTH Power and decreased as compared to plan in WCHE. That being said, one large project or fleet replacement in a given year can affect the variance a great deal.

Figure 34 below details the comparison of total planned capital expenses with actual spends detailed for the System Access category for the legacy ERTH Power area vs the WCHE area and totaled over the period from 2018-2023.

Figure 34: Plan vs Actual System Access Total 2018-2023: by Area



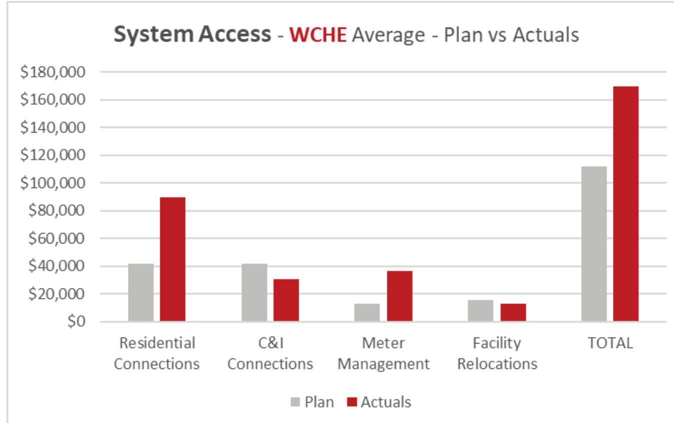
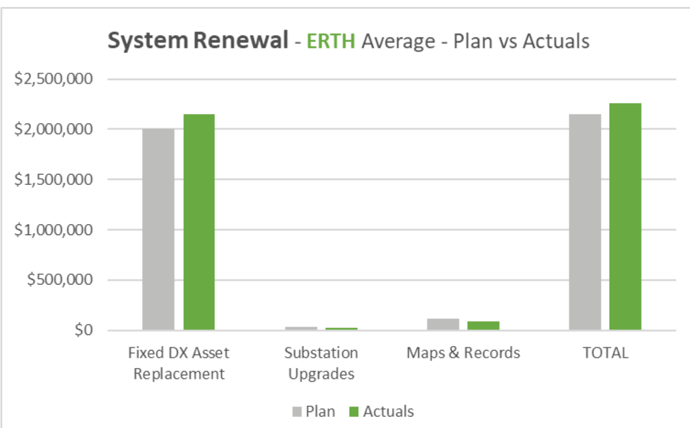


Figure 35 below details the comparison of total planned capital expenses with actual spends detailed for the System Renewal category for the legacy ERTH Power area vs the WCHE area and totaled over the period from 2018-2023.

Figure 35: Plan vs Actual System Renewal Total 2018-2023: by Area



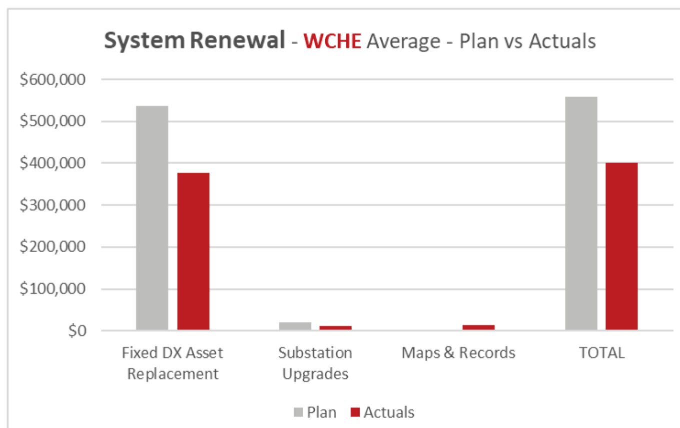
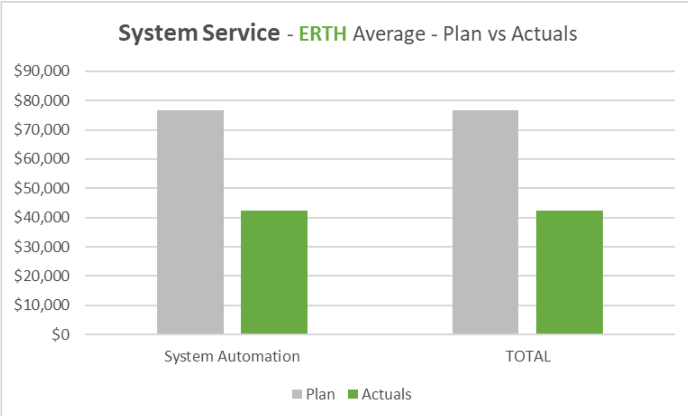


Figure 36 below details the comparison of total planned capital expenses with actual spends detailed for the System Service category for the legacy ERTH Power area vs the WCHE area and totaled over the period from 2018-2023.

Figure 36: Plan vs Actual System Service Total 2018-2023: by Area



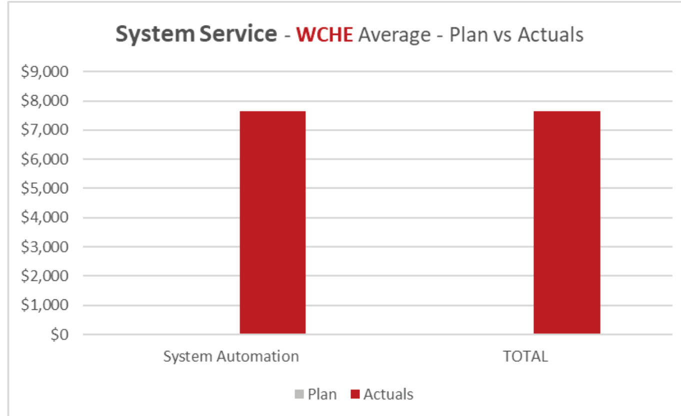
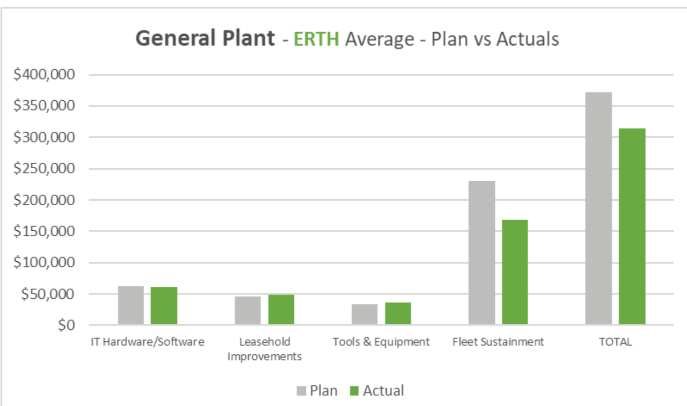
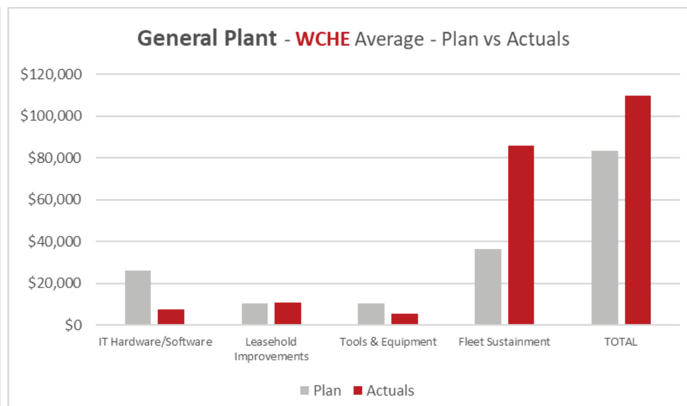


Figure 37 below details the comparison of total planned capital expenses with actual spends detailed for the General Service category for the legacy ERTH Power area vs the WCHE area and totaled over the period from 2018-2023.

Figure 37: Plan vs Actual General Service Total 2018-2023: by Area





5.4.1.2 Forecast Expenditures

The following section is an analysis of a distributor's capital expenditures for the DSP's forecast period. The capital forecast calls for an increasing investment from $2.76 Million in 2025 to $3.11 Million in 2029 as detailed in **Table 28.**

Table 28: Capital Forecast 2025-2029

CATEGORY		2024 Plan	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	Average (2025 to 2029)	Average % of Plan
System Access	Residential Connections	$200,000	$450,000	$459,000	$468,180	$477,544	$487,094	$468,364	7.2%
	C&I Connections	$100,000	$183,449	$187,118	$190,860	$194,677	$198,571	$190,935	2.9%
	Meter Management	$266,750	$250,835	$255,851	$1,385,968	$1,385,968	$1,391,188	$933,962	14.3%
	Facility Relocations	$85,000	$177,593	$181,145	$184,767	$188,463	$192,232	$184,840	2.8%
	TOTAL	$651,750	$1,061,876	$1,083,114	$2,229,776	$2,246,652	$2,269,085	$1,778,101	27.3%
System Renewal	Fixed DX Asset Replacement	$2,497,000	$2,900,000	$3,077,500	$3,255,000	$3,432,500	$3,610,000	$3,255,000	49.9%
	Substation Upgrades	$310,000	$181,842	$82,798	$33,782	$34,795	$35,839	$73,811	1.1%
	Maps & Records	$85,000	$104,320	$106,406	$108,534	$110,705	$112,919	$108,577	1.7%
	TOTAL	$2,892,000	$3,186,162	$3,266,704	$3,397,316	$3,578,000	$3,758,758	$3,437,388	52.7%
System Service	System Automation	$34,800	$120,000	$122,400	$124,848	$127,345	$129,892	$124,897	1.9%
	Capacity Upgrades	$0	$0	$0	$0	$0	$0	$0	0.0%
	TOTAL	$34,800	$120,000	$122,400	$124,848	$127,345	$129,892	$124,897	1.9%
General Plant	IT Hardware/Software	$164,000	$344,550	$1,188,254	$514,135	$470,093	$472,795	$597,965	9.2%
	Leasehold Improvements	$45,000	$15,000	$15,300	$15,606	$15,918	$16,236	$15,612	0.2%
	Tools & Equipment	$56,500	$58,478	$59,647	$60,840	$62,057	$63,298	$60,864	0.9%
	Fleet Sustainment	$882,701	$697,701	$445,000	$445,000	$350,000	$575,000	$502,540	7.7%
	TOTAL	$1,148,201	$1,115,729	$1,708,201	$1,035,581	$898,067	$1,127,330	$1,176,982	18.1%
	TOTAL CAPITAL SPEND	**$4,726,751**	**$5,483,767**	**$6,180,419**	**$6,787,521**	**$6,850,064**	**$7,285,065**	**$6,517,367**	**100.0%**

5.4.1.2.1 System Access Investments

System Access investments are modifications to the existing system that will allow customers to access electricity services. These investments represent an obligation of ERTH Power to provide service and are based on customer request consistent with the ERTH Power Conditions of Service.

Forecast investments are estimates based on consultation activities described in Section 5.2.2 and typically include new residential services, new C&I connections, meter reverifications and replacements, and Facility Relocations (i.e. road widening and other modifications requested by others). The investment forecast is illustrated in ***Table 29.***

Table 29: Capital Forecast System Access

		Test Yr	Forecast						
CATEGORY		2024 Plan	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	Average (2025 to 2029)	Average % of Plan
System Access	Residential Connections	$200,000	$450,000	$459,000	$468,180	$477,544	$487,094	$468,364	7.2%
	C&I Connections	$100,000	$183,449	$187,118	$190,860	$194,677	$198,571	$190,935	2.9%
	Meter Management	$266,750	$250,835	$255,851	$1,385,968	$1,385,968	$1,391,188	$933,962	14.3%
	Facility Relocations	$85,000	$177,593	$181,145	$184,767	$188,463	$192,232	$184,840	2.8%
	TOTAL	$651,750	$1,061,876	$1,083,114	$2,229,776	$2,246,652	$2,269,085	$1,778,101	27.3%

5.4.1.2.2 System Renewal Investments

System Renewal investments are those distribution system projects such as pole line replacement, transformer replacement and underground cable rehabilitation and replacement, as well as Substation

Upgrades, and Asset Management mapping and records. These investments represent sustainment of asset health to delivers suitable levels of reliability based on reliability statistics discussed in Section 5.2.3.

Forecast investments are based on the asset condition reported in Section 5.3.2 and are paced at a rate to avoid future rate shock that could arise if renewal investments are deferred. The investment forecast is illustrated in **Table 30.**

Table 30: Capital Forecast System Renewal

		Test Yr	Forecast					Average	Average
		2024	2025	2026	2027	2028	2029	(2025 to 2029)	% of Plan
CATEGORY		Plan	Plan	Plan	Plan	Plan	Plan		
System Renewal	Fixed DX Asset Replacement	$2,497,000	$2,900,000	$3,077,500	$3,255,000	$3,432,500	$3,610,000	$3,255,000	49.9%
	Substation Upgrades	$310,000	$181,842	$82,798	$33,782	$34,795	$35,839	$73,811	1.1%
	Maps & Records	$85,000	$104,320	$106,406	$108,534	$110,705	$112,919	$108,577	1.7%
	TOTAL	$2,892,000	$3,186,162	$3,266,704	$3,397,316	$3,578,000	$3,758,758	$3,437,388	52.7%

5.4.1.2.3 System Service Investments

System Service investments are those projects such that are intended to improve reliability or provide new service options. These investments in this area generally include Grid Modernization, System Automation and Customer Service enhancements.

Forecast investments are based on long-term plans and are illustrated in ***Table 31.***

Table 31: Capital Forecast System Service

		Test Yr	Forecast					Average	Average
		2024	2025	2026	2027	2028	2029	(2025 to 2029)	% of Plan
CATEGORY		Plan	Plan	Plan	Plan	Plan	Plan		
System Service	System Automation	$34,800	$120,000	$122,400	$124,848	$127,345	$129,892	$124,897	1.9%
	Capacity Upgrades	$0	$0	$0	$0	$0	$0	$0	0.0%
	TOTAL	$34,800	$120,000	$122,400	$124,848	$127,345	$129,892	$124,897	1.9%

5.4.1.2.4 General Service Investments

General Service investments are those projects that do not directly impact the distribution system but rather support the operations of the utility. Investments in this area include IT infrastructure, facilities management, tools and equipment, and fleet.

Forecast investments are based on estimates of activity and are illustrated in ***Table 32.***

Table 32: Capital Forecast General Service

		Test Yr	Forecast					Average	Average
		2024	2025	2026	2027	2028	2029	(2025 to 2029)	% of Plan
CATEGORY		Plan	Plan	Plan	Plan	Plan	Plan		
General Plant	IT Hardware/Software	$164,000	$344,550	$1,188,254	$514,135	$470,093	$472,795	$597,965	9.2%
	Leasehold Improvements	$45,000	$15,000	$15,300	$15,606	$15,918	$16,236	$15,612	0.2%
	Tools & Equipment	$56,500	$58,478	$59,647	$60,840	$62,057	$63,298	$60,864	0.9%
	Fleet Sustainment	$882,701	$697,701	$445,000	$445,000	$350,000	$575,000	$502,540	7.7%
	TOTAL	$1,148,201	$1,115,729	$1,708,201	$1,035,581	$898,067	$1,127,330	$1,176,982	18.1%

5.4.1.3 Comparison of Forecast & Historical Expenditures

Table 33 illustrates an analysis of capital expenditures in the DSP's forecast period compared to the historical period.

Table 33: Comparison of Forecast and Historical Expenditures

	Historical Capital Expenditures						Bridge	Forecast Period				
CATEGORY	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
System Access	$1,130,388	$1,329,817	$1,023,612	$1,236,714	$1,448,846	$959,222	$651,750	$1,061,876	$1,083,114	$2,229,776	$2,246,652	$2,269,085
System Renewal	$2,396,984	$2,804,960	$2,802,524	$2,634,249	$2,549,683	$2,778,831	$2,892,000	$3,186,162	$3,266,704	$3,397,316	$3,578,000	$3,758,758
System Service	$183,225	$26,011	$0	$6,108	$114,378	$95,720	$34,800	$120,000	$122,400	$124,848	$127,345	$129,892
General Plant	$316,491	$201,215	$421,932	$455,688	$660,246	$451,931	$1,148,201	$1,115,729	$1,708,201	$1,035,581	$898,067	$1,127,330
NET Capital Expenditures	**$4,027,088**	**$4,362,003**	**$4,248,068**	**$4,332,759**	**$4,773,153**	**$4,285,704**	**$4,726,751**	**$5,483,767**	**$6,180,419**	**$6,787,521**	**$6,850,064**	**$7,285,065**
Capital Contributions	$1,242,463	$1,198,940	$2,755,666	$1,495,459	$1,386,904	$1,945,209	$1,828,994	$2,121,918	$2,391,484	$2,626,399	$2,650,600	$2,818,921
GROSS Capital Expenditures	**$5,269,550**	**$5,560,943**	**$7,003,734**	**$5,828,218**	**$6,160,057**	**$6,230,913**	**$6,555,745**	**$7,605,684**	**$8,571,903**	**$9,413,920**	**$9,500,664**	**$10,103,986**

5.4.1.4 Important Modifications to Capital Programs since Last DSP

ERTH Power is continuing to track Capital Programs with the same classifications as previous DSP filings with the main modification being the integration of the assets from the formerly Goderich service area into a combined program with commensurate increases in spending.

5.4.1.5 Forecast Impact of System Investments on System O&M Costs

Table 34 details the Impact on System O&M costs of the capital plan over the forecast period.

Table 34: Forecast O&M

	Forecast Period				
CATEGORY	**2025**	**2026**	**2027**	**2028**	**2029**
System O&M	**$2,762,738**	**$2,845,621**	**$2,930,989**	**$3,018,919**	**$3,109,486**

With growth in customer connections comes growth number of assets in service and a commensurate growth in O&M costs. ERTH Power will manage it operation to optimize costs between O&M and Capital but some costs remain fixed. For instance new assets need to be added to the maintenance schedules and all asset regardless of renewal status are subject to mandatory inspection as mandated in the DCS.

While planned asset renewal can have a large impact on overall costs by reducing unplanned incidents and thus reducing outage costs and "unplanned capital" costs, the overall impact in O&M costs is low.

5.4.1.6 Non-Distribution Activities

There are no expenditures for non-distribution activities in this Capital Plan.

5.4.2 JUSTIFYING CAPITAL EXPENDITURES

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate identification, optimization, prioritization, pacing of capital-related expenditures, and how it developed its overall *capital budget envelope. A distributor should also keep pace with technological changes and integrate cost-effective innovative investments and traditional planning needs such as load growth, asset condition and reliability.*

A distributor must not only provide information to justify each individual investment, but also the total amount of its proposed capital expenditures. A distributor should provide context on how its overall capital expenditures over the next five years, as a whole, will achieve the distributor's objectives. Particularly, a distributor should comment on lumpy investment years and rate impacts of capital investments in the long-term.

5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g., unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment. The following are guidelines on the information to be provided for any material investment.

A. General Information on the project/program

A distributor is expected to provide information about the investment, which includes the need, scope, volume of work expected to be completed, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should also be included.

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

B. Evaluation criteria and information requirements for each project/program

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the investments that are not outputs of the asset management process.

Justifying an investment can be demonstrated through evidence of accepted distributor practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration.

As such. the distributor should fully explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid optimization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors may seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

5.4.2.1.1 Project Narratives (Assessment Forms)

ERTH Power has included the following project narratives:

4.2.1.1.1 System Access

- Residential Connections
- C&I Connections
- Meter Management
  - AMI 2.0 *(spend included in Meter Management, but specific Project Narrative created)*
- Facility Relocations

4.2.1.1.2 System Renewal

- Fixed Distribution Asset Replacement *(overall spend aligns with Capital forecast tables - includes the following which have separate project narratives included for 2025 spend specifically)*
  - Substation Upgrades
  - Maps & Records
  - Pole Replacements Program
  - Transformer Painting Program
  - Unplanned Capital Projects
  - AYL-OHCONV-Parkview Heights (2025 specific project)
  - AYL-OHCONV-South St. E. (2025 specific project)
  - CLI-OHCONV-Albert St. Alley (2025 specific project)
  - GDE-OHCONV-Blake & Gibbons (2025 specific project)
  - ING-OHCONV-Victoria Park (2025 specific project)

- ING-UGCONV-Oxford Lane (2025 specific project)
- MIT-UGCONV-Maple & St. Andrews St. (2025 specific project)
- MIT-UGCONV-Rattenbury St. E. (2025 specific project)
- MIT-UGCONV-St. David St. (2025 specific project)
- PTS-OHCONV-Walnut St. (2025 specific project)
- TAV-OHCONV-Wellington St. (2025 specific project)

4.2.1.1.3 System Service

- System Automation

4.2.1.1.4 General Plant

- IT Hardware/Software
  - ERP System Upgrade *(spend included in IT line item, but specific Project Narrative created)*
- Leasehold Improvements
- Fleet Management

See ***Appendix K*** for detailed narratives.

Appendices

APPENDIX A. 2023 ERTH Customer Service Satisfaction Survey

ADVANIS for ERTH POWER

2023 Customer Satisfaction Survey

March 2023

ADVANIS
Confidential

CRIC

Deliverables

Advanis is pleased to provide **this report with results of the 2023 Customer Satisfaction study**.

- We include comparisons to previous years of the study, where applicable.

In addition to this report, you have access to **Advanis' Online Reporting Environment** (ORE) which allows you to:

- create charts and tables like those contained in this report
  - you will be able to do much more analysis than we had space for in this overall report (e.g., look at results comparing segments of the annual consumption index or the regions within your LDC, if applicable)
- review the verbatim responses to:
  - the open-ended question "Is there anything you would like your LDC to do to improve its services to you?".
  - Note that you can export the verbatim responses to Excel at the click of a button; and
  - search for key words or filter the results by different segments (e.g., customer type, region) or other questions in the survey.

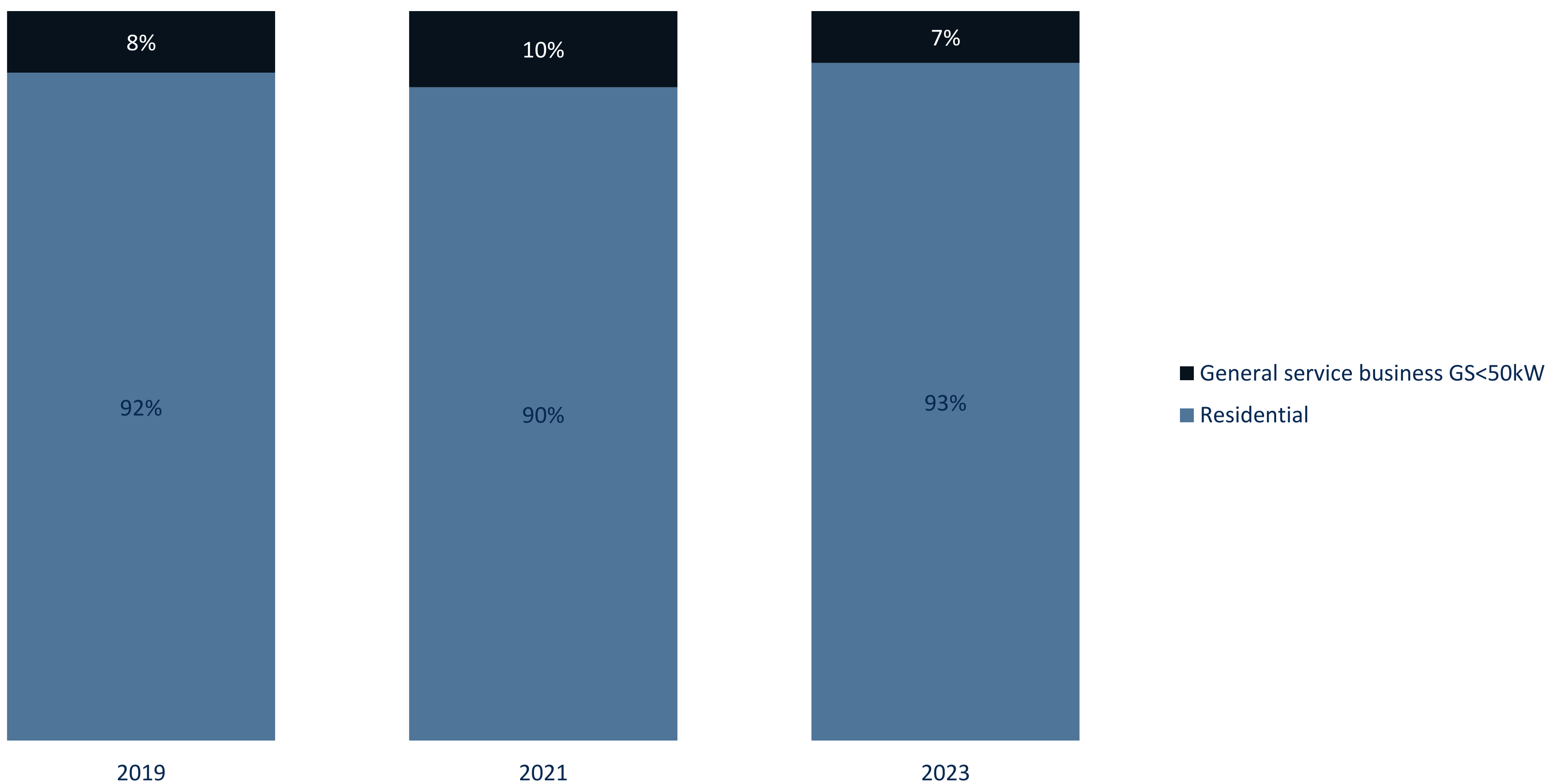
To access the ORE, visit this link: portal.advanis.net and enter your username in the format firstname_lastname. If you've forgotten your password, there is a link to reset it on the login page. If you have any questions, please contact Gary.Offenberger@advanis.net.

Contents

Lead Consultant: Gary.Offenberger@advanis.net // 780.229.1140

Customer (i.e., Survey Respondent) Profile

Customer Type - information provided by ERTH Power



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

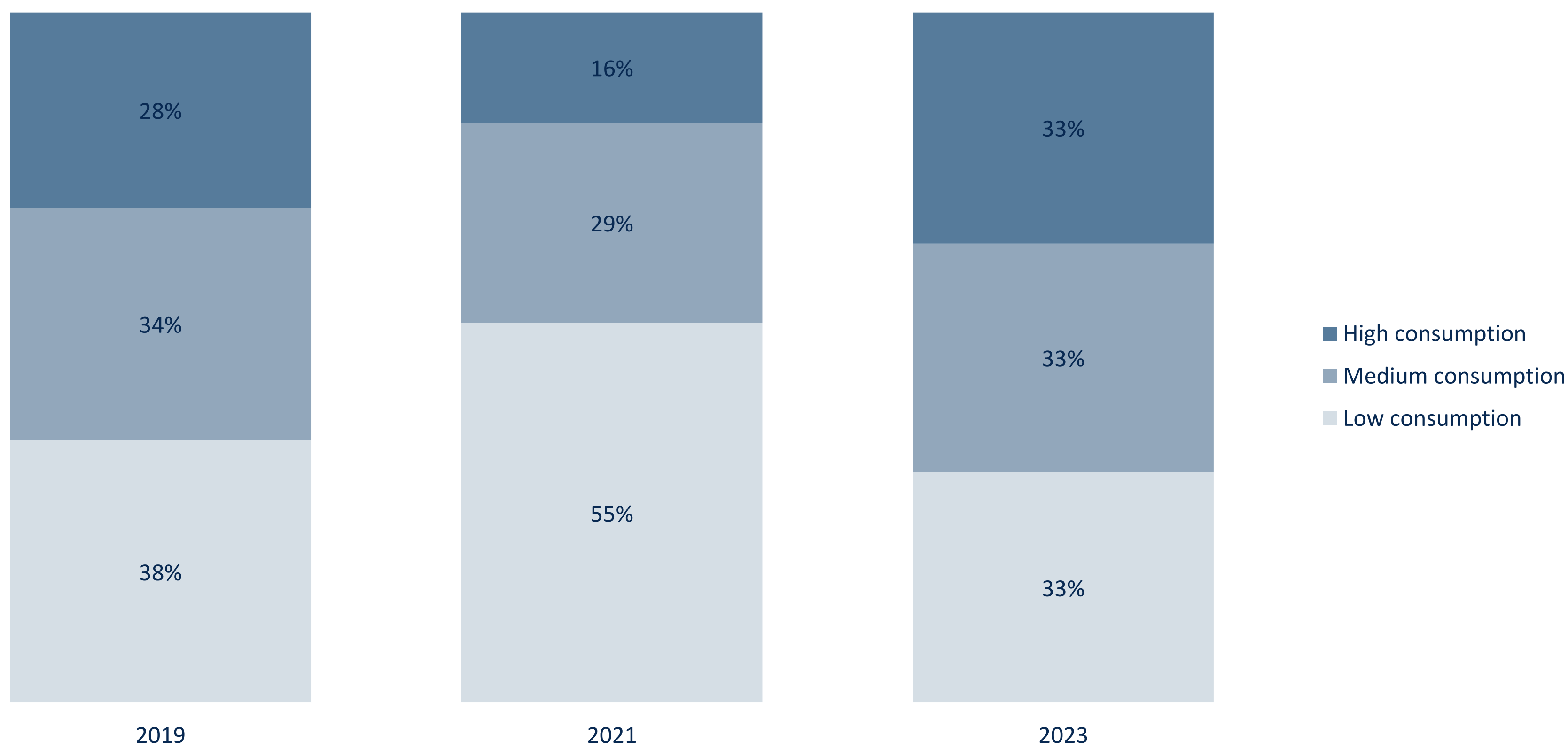
Region - information provided by ERTH Power

	2019	2021	2023
Aylmer	16%	13%	13%
Beachville	2%	2%	2%
Belmont	4%	4%	4%
Burgessville	1%	1%	1%
Clinton	9%	7%	7%
Embro	2%	2%	2%
Goderich [2021 onwards; added in 2019 but after Csat]		17%	16%
Ingersoll	28%	24%	23%
Norwich	7%	6%	6%
Otterville	2%	2%	2%
Port Stanley	8%	7%	7%
Tavistock	7%	6%	6%
Thamesford	3%	3%	3%
West Perth	11%	9%	10%
Base	402	401	403

Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

Arrow indicates statistically significant change at the 95% level.

Indexed score of annual consumption (Only have GS data for 2023 onwards) - information provided by ERTH Power

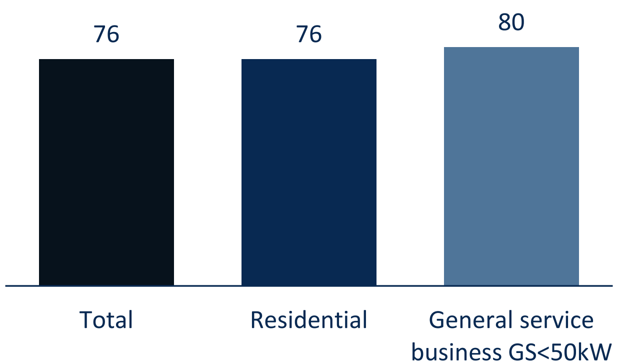


Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

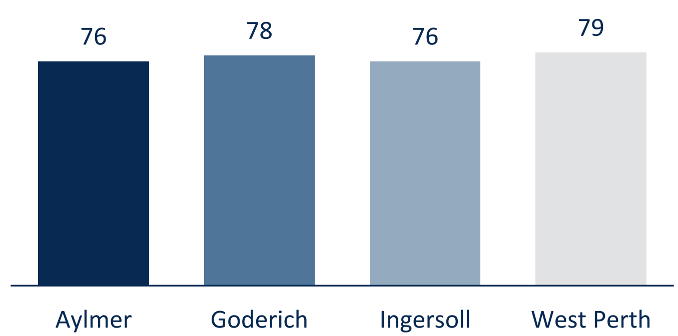
Customer Satisfaction Index Score – 2023 Results & Trend

Customer Satisfaction Index: ERTH for 2023

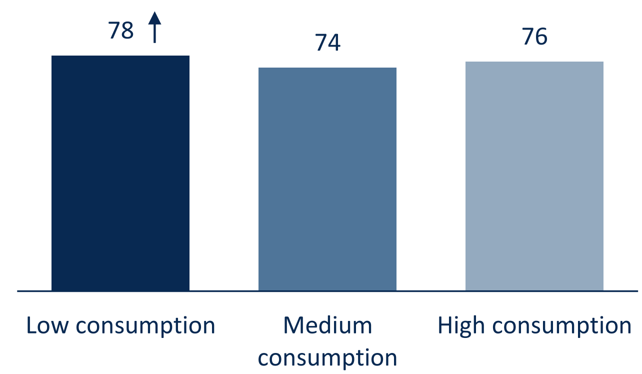
CSI Score – Total and by Customer Type



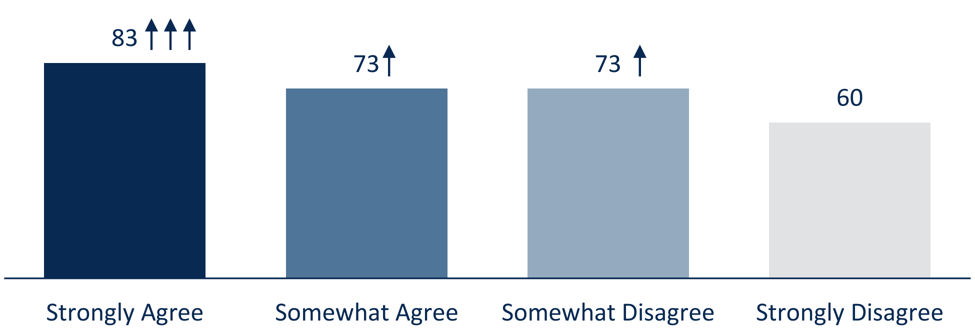
CSI Score by Region
(only regions with ~40 or more completed surveys)



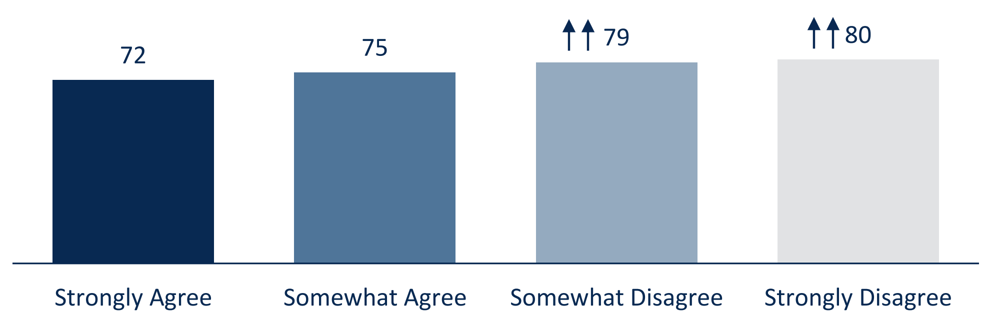
CSI Score by Annual Consumption Index



CSI Score for each segment of agreement with:
"Customers are well served by the electricity system in Ontario"



CSI Score for each segment of agreement with:
"The cost of my electricity bill has a major impact [on my personal finances] / [the bottom line of my organization]"



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023; LDC: ERTH Power
Note: Arrows denote statistically higher than other segment(s) at 95% confidence level; sometimes an apparent difference is not statistically significant because of low base size in a segment

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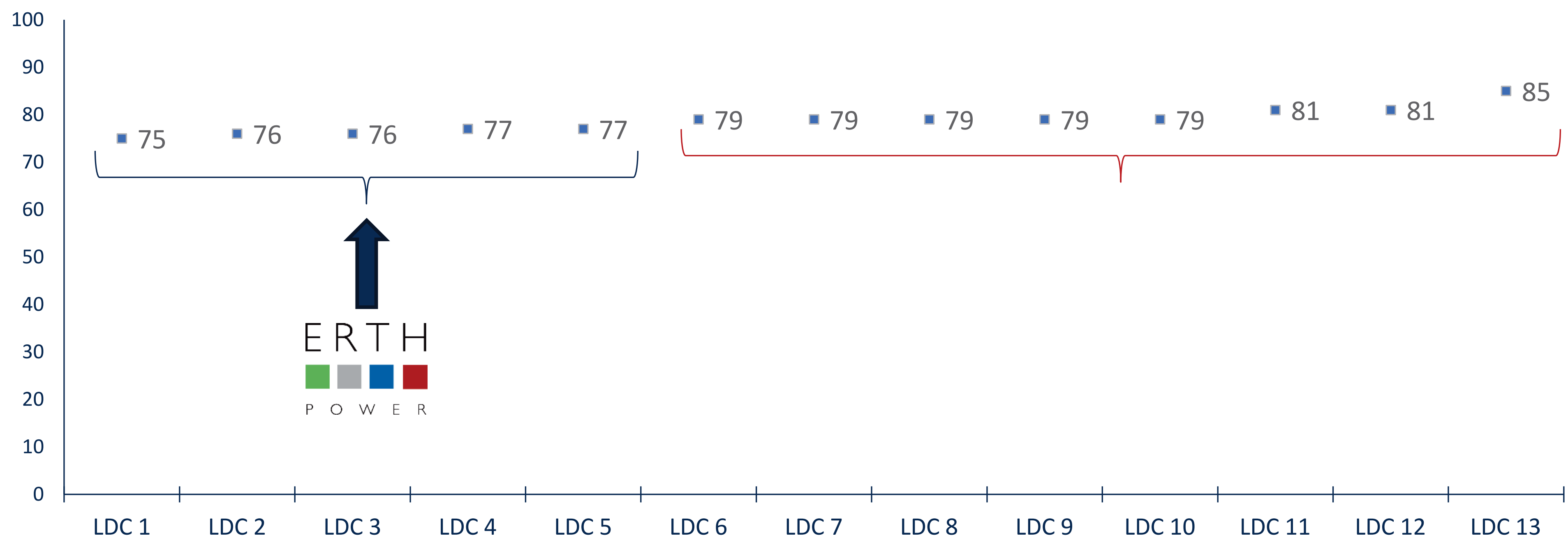
Customer Satisfaction Index: Compared to Other CHEC Members

- In 2023, ERTH's score of 76 is *statistically* the same as that of 4 other LDCs.
- ERTH's score is *statistically* lower than that of 8 other LDCs.



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023
Note: Statistical differences at 95% confidence level; sometimes an apparent difference is not statistically significant because of low base size in a segment

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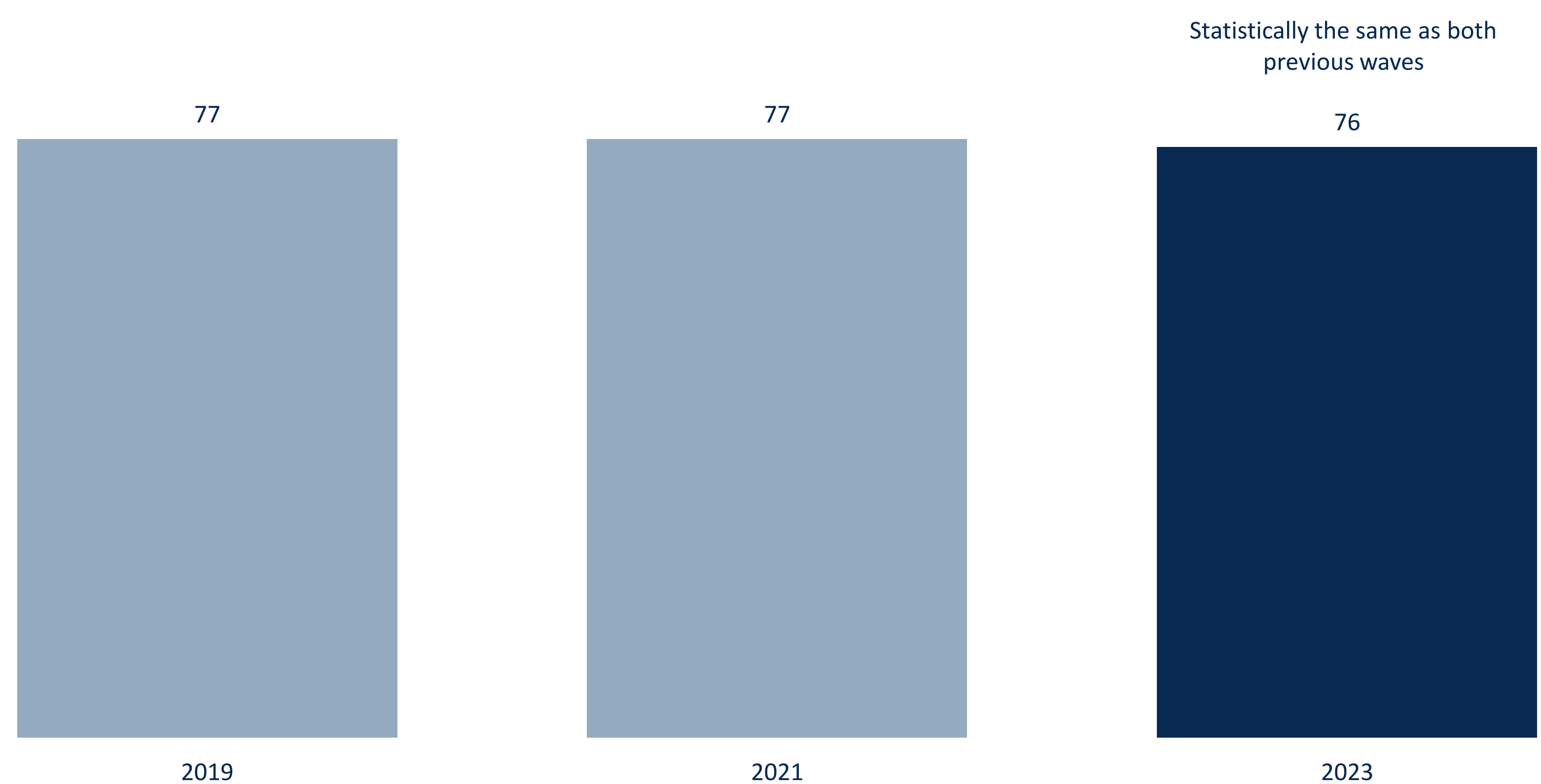
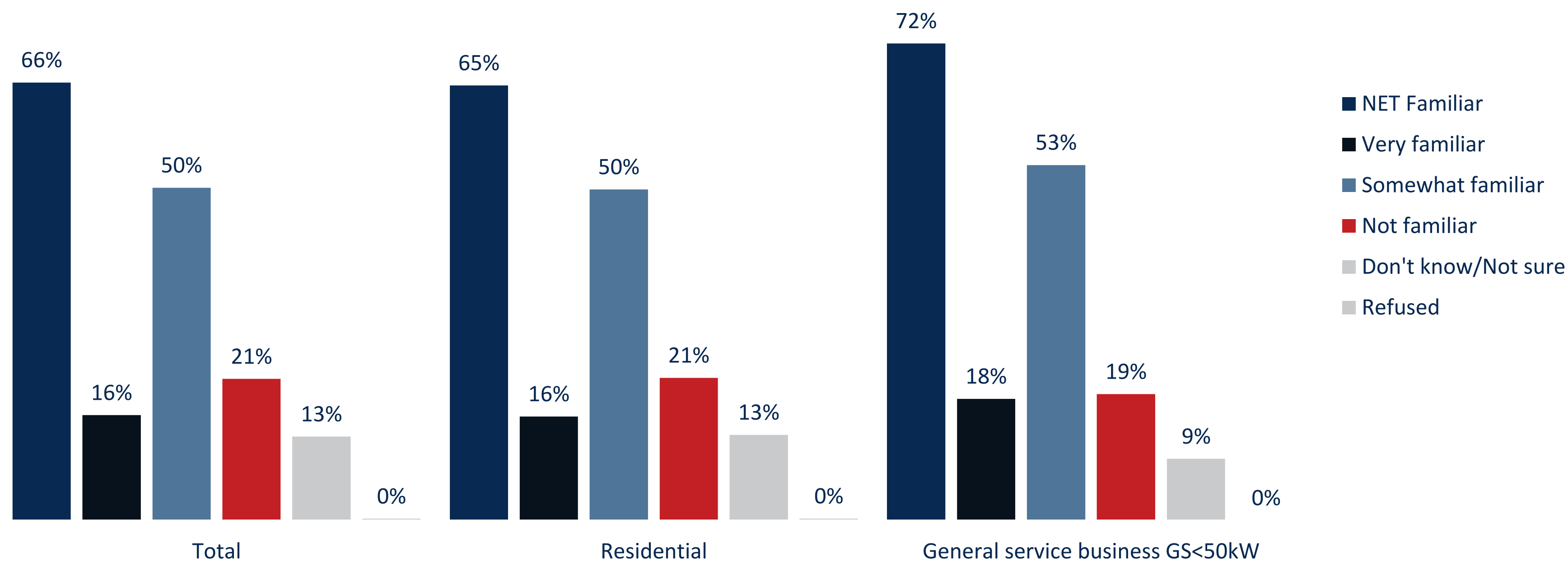
ERTH Power's Customer Satisfaction Index by Year



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power
Note: Statistical differences at 95% confidence level; sometimes an apparent difference is not statistically significant because of low base size in a segment

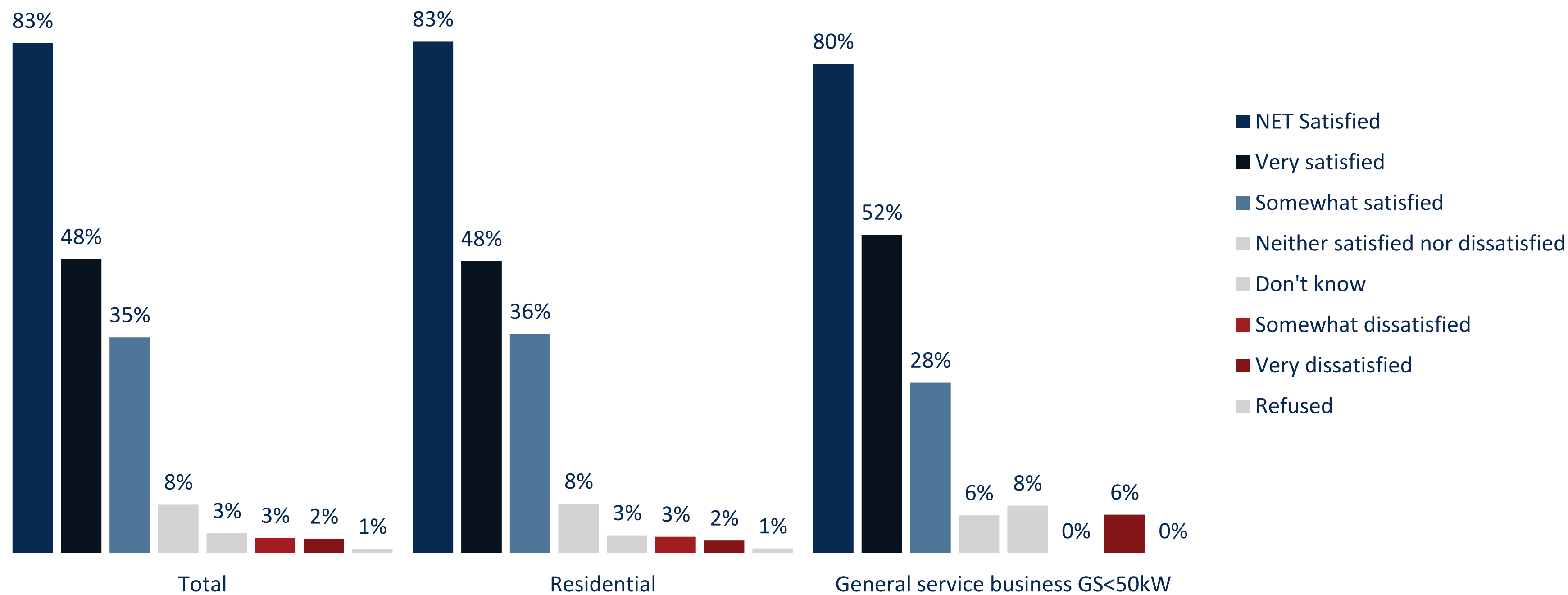
Core (OEB) Survey Questions – 2023 Results

How familiar are you with ERTH Power, which operates the electricity distribution system in your community?



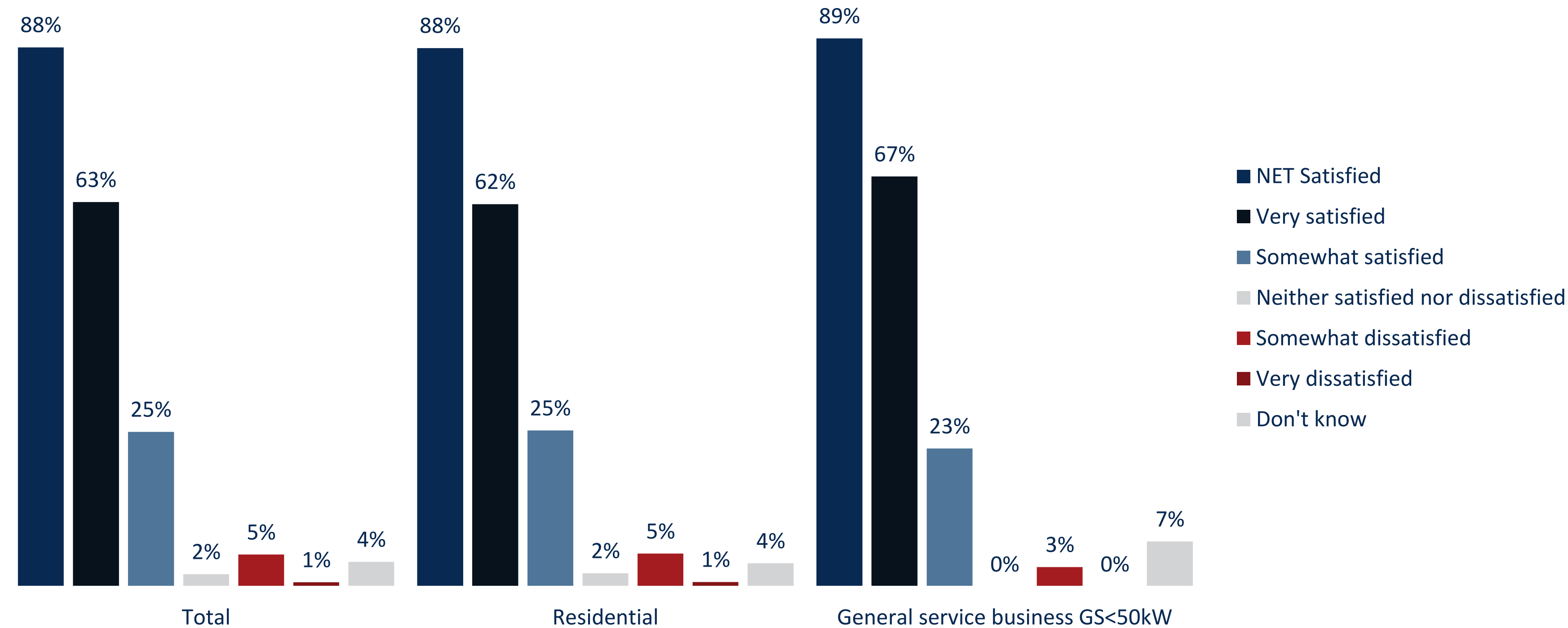
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

Thinking specifically about the services provided to you and your community by ERTH Power, OVERALL, how satisfied are you with the services that you receive?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

How satisfied are you with the electrical service that you receive from ERTH Power - based on the RELIABILITY of your electrical service as judged by the number of outages you experience?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

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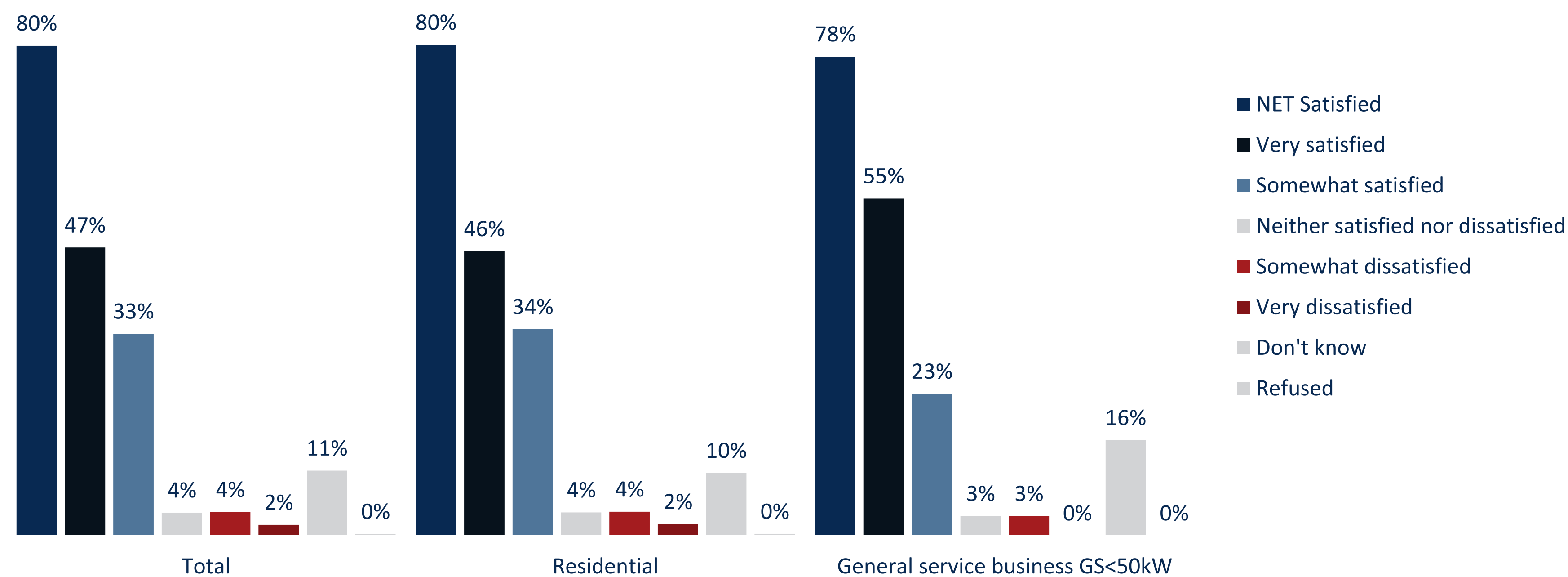
How satisfied are you with the electrical service that you receive from ERTH Power - based on the amount of TIME IT TAKES TO RESTORE POWER when outages occur?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

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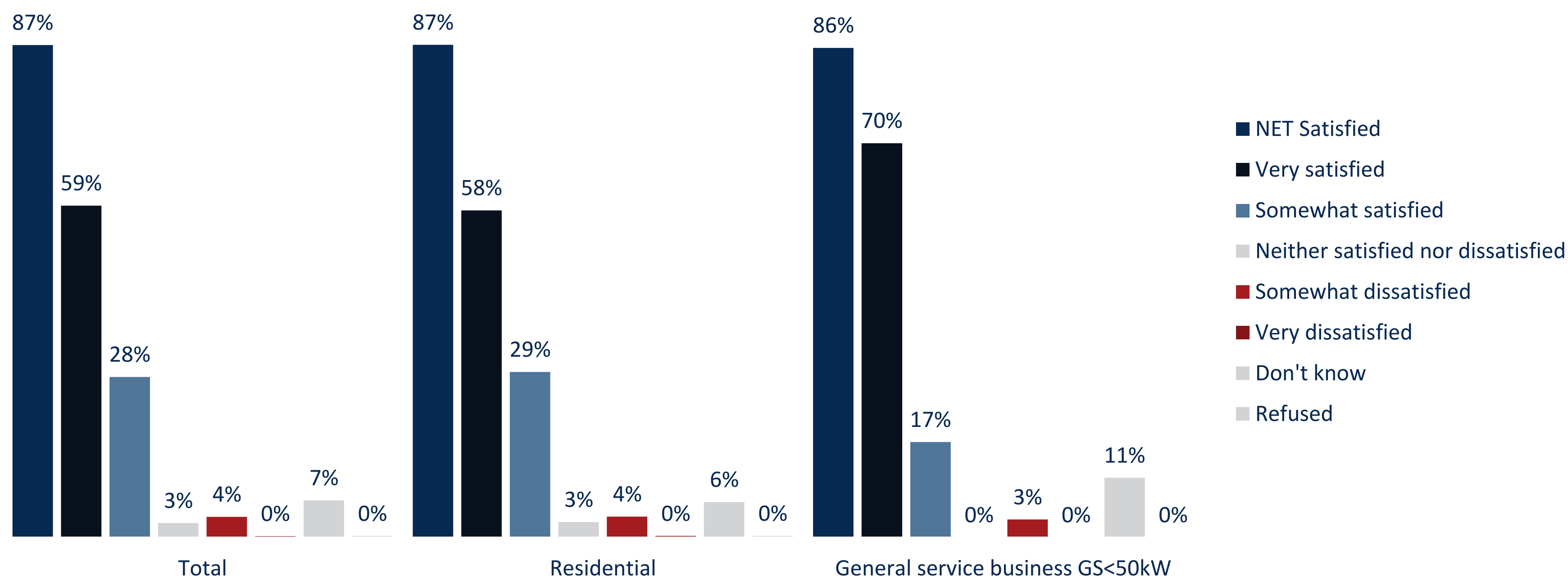
How satisfied are you with the electrical service that you receive from ERTH Power - based on the QUALITY OF THE POWER delivered to you as judged by the absence of voltage fluctuations that can result in flickering/dimming of lights / an affect on equipme



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

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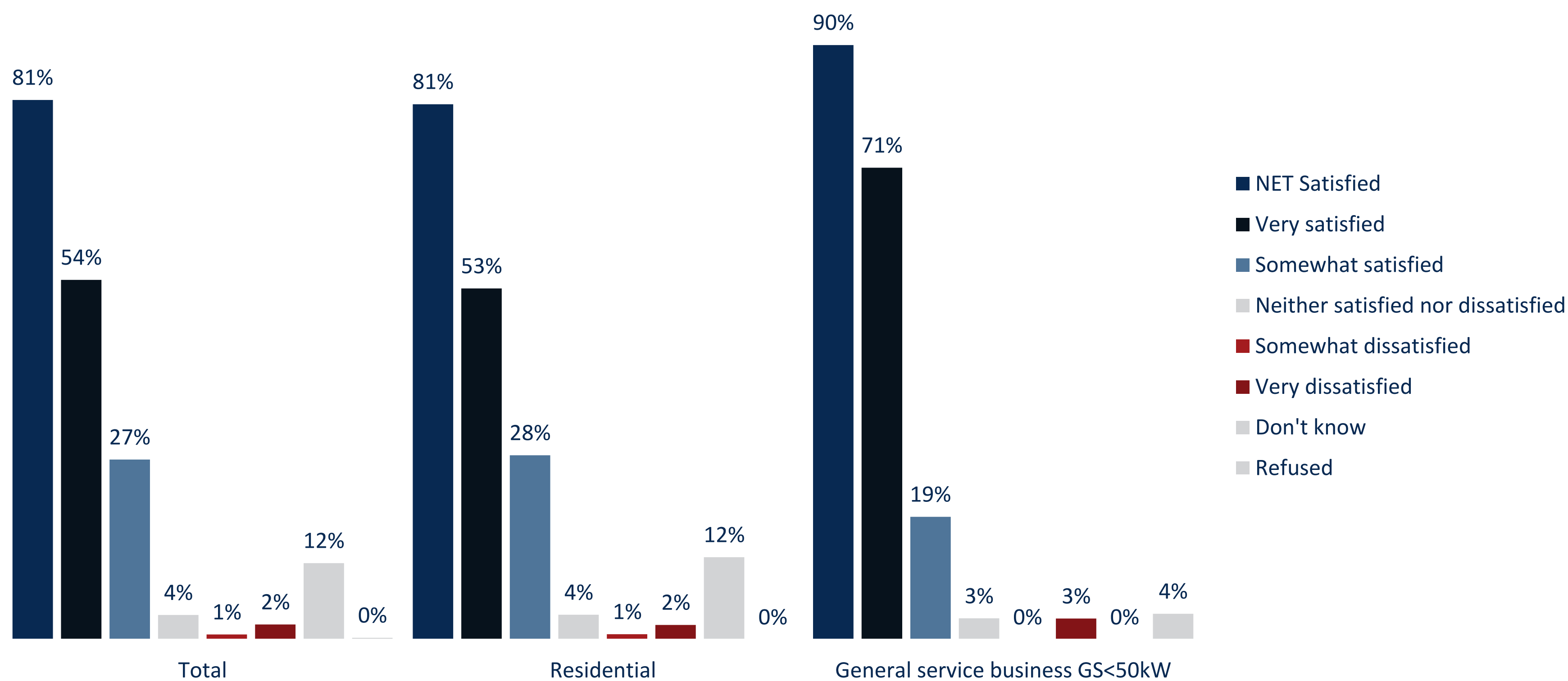
How satisfied are you with the bills that you receive from ERTH Power - based on them providing ACCURATE BILLS?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

ADVANIS
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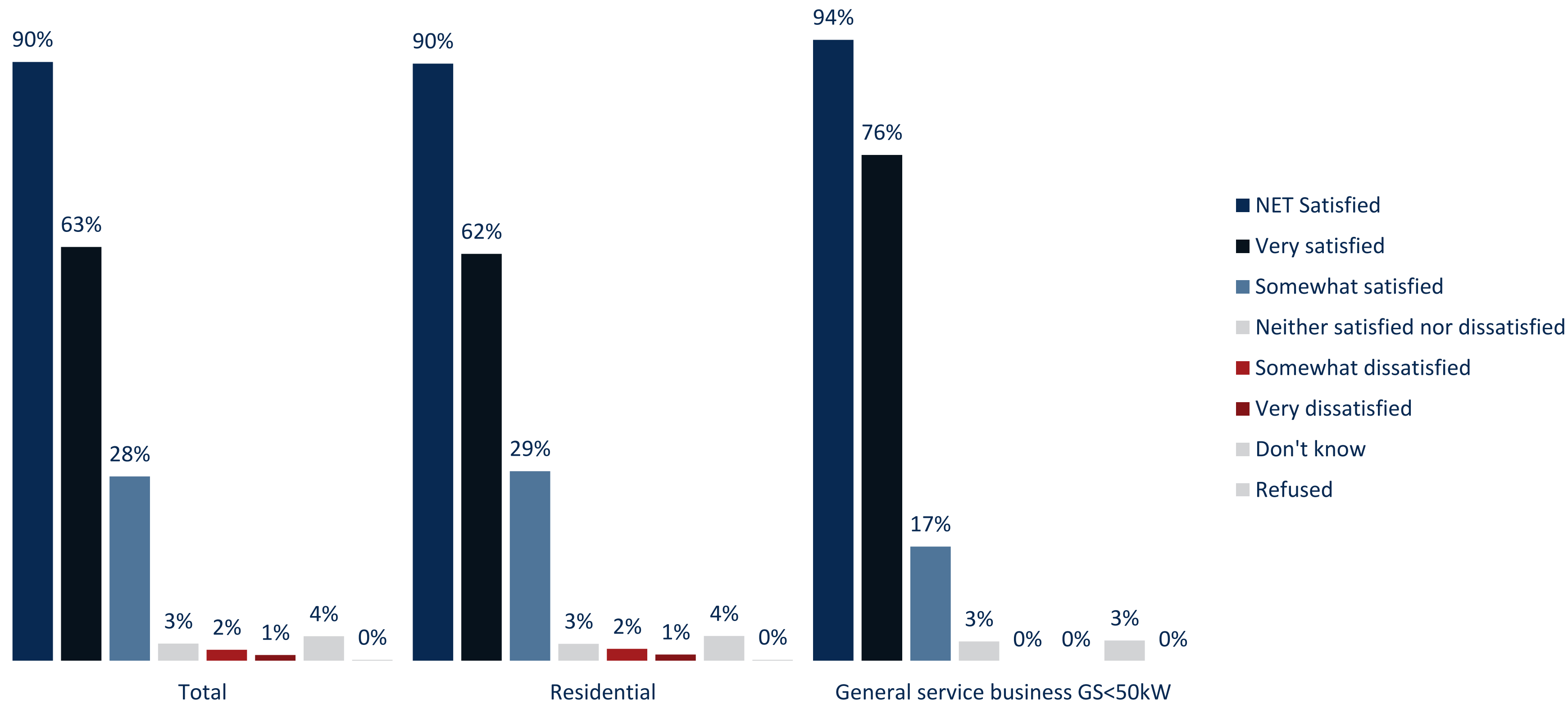
How satisfied are you with the bills that you receive from ERTH Power - based on them providing CONVENIENT OPTIONS TO RECEIVE AND PAY BILLS?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

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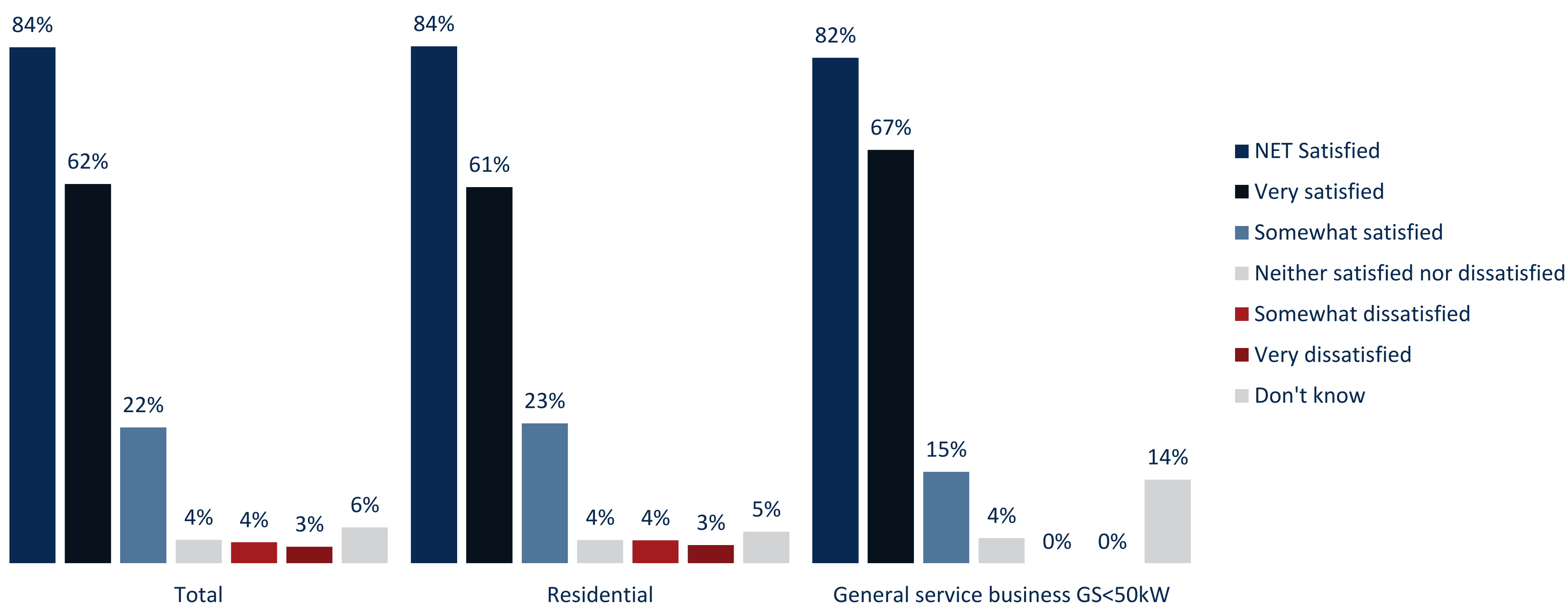
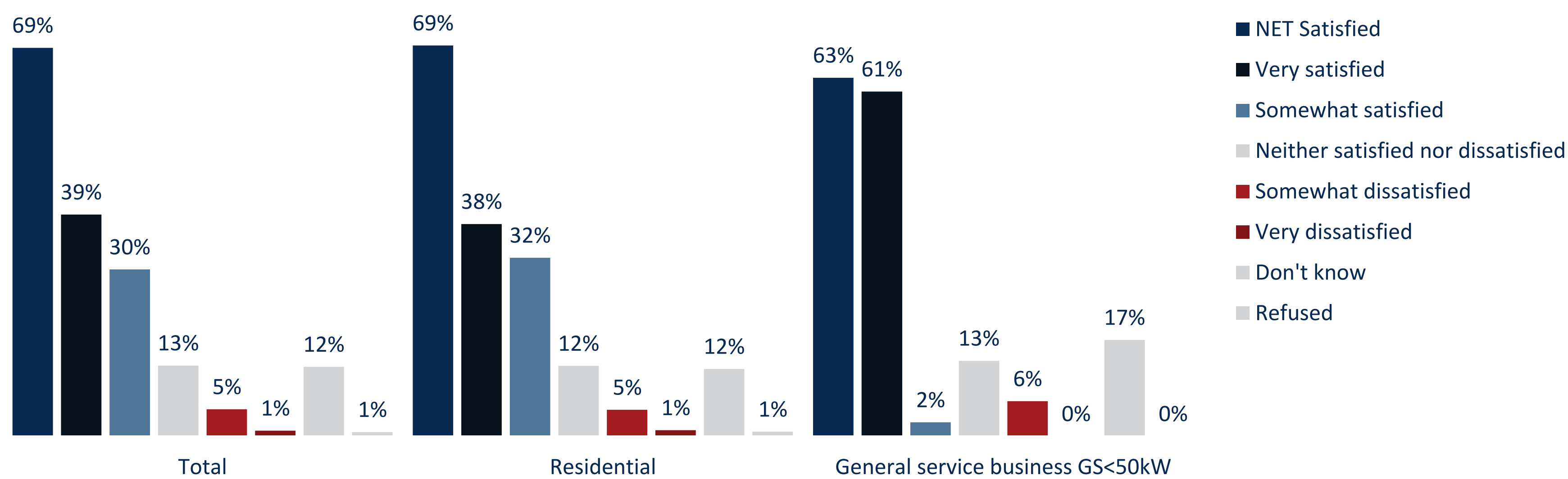
How satisfied are you with the CUSTOMER SERVICE you have received when dealing with employees of ERTH Power, whether on the telephone, via email, in person or through online conversations including social media?



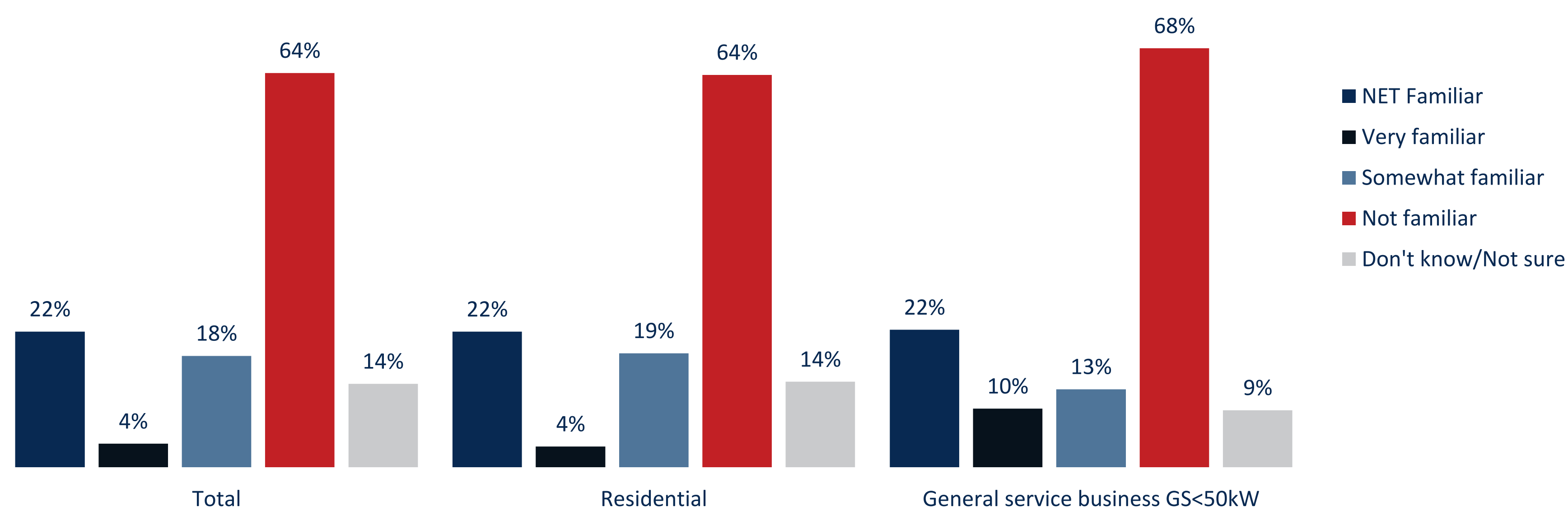
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power
Note: Base excludes those who indicated that they had not contacted customer service, thus could not provide an assessment

How satisfied are you with the COMMUNICATIONS that you may receive from ERTH Power without talking directly to an employee, including information found on their website, bill inserts, advertising, notices, emails, or social media sites?



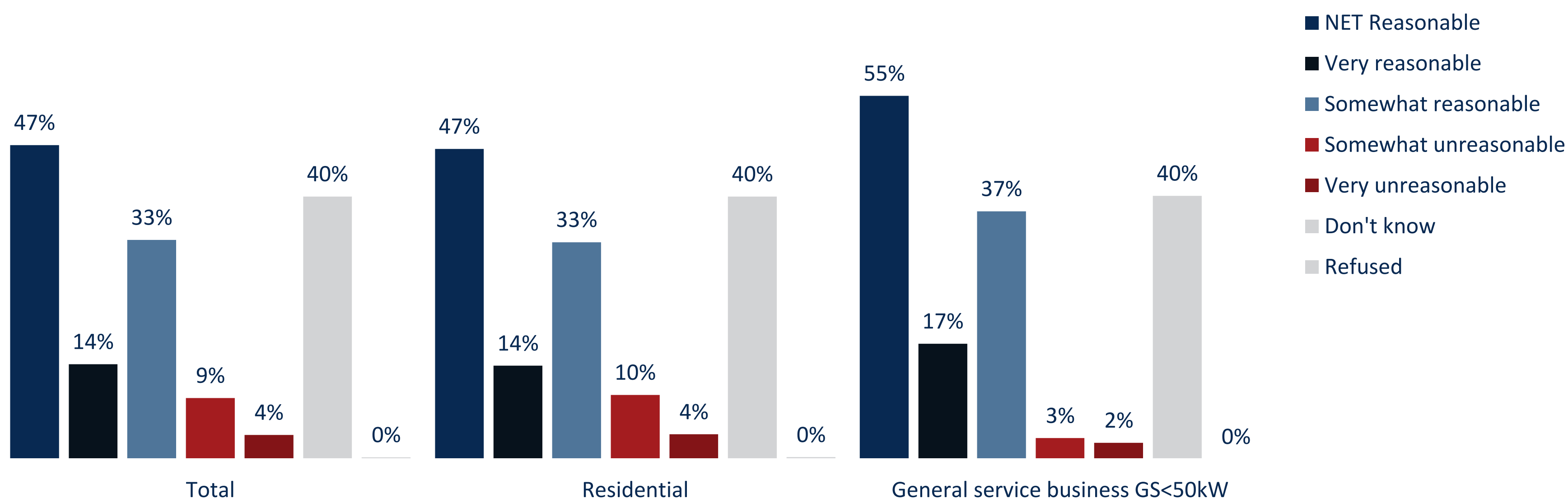
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

How familiar are you with the percentage of your electricity bill that went to ERTH Power? So, NOT the portions allocated to power generation companies, transmission companies, the provincial government and regulatory agencies.



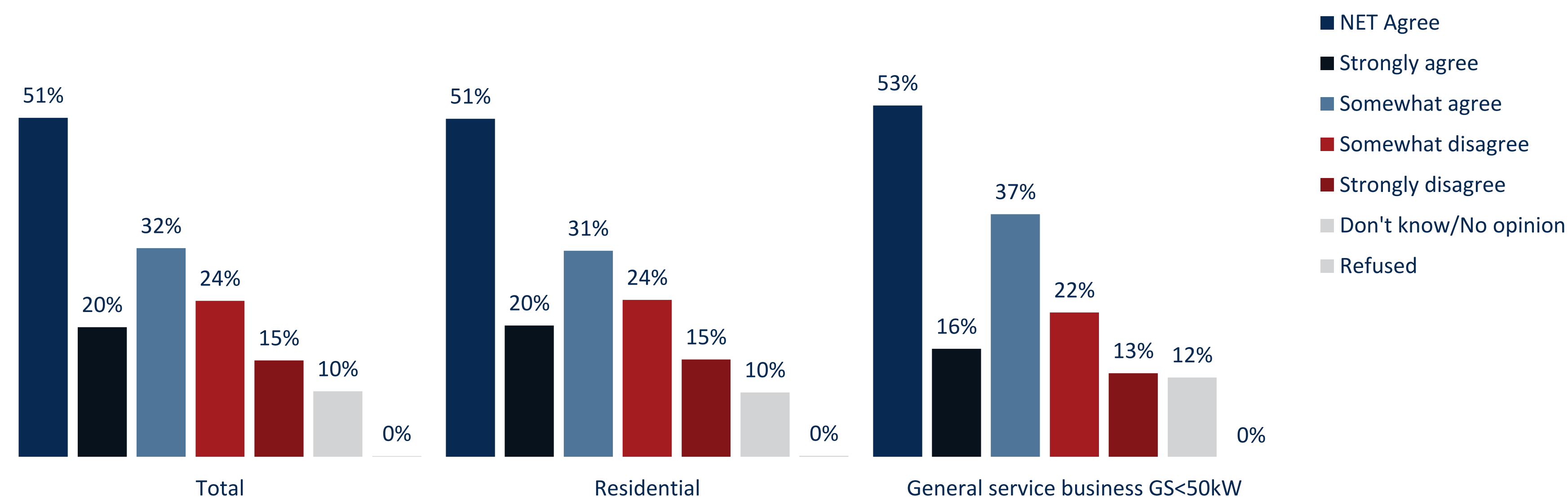
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

Do you feel that the percentage of your total electricity bill that you pay to ERTH Power for the services they provide is...?



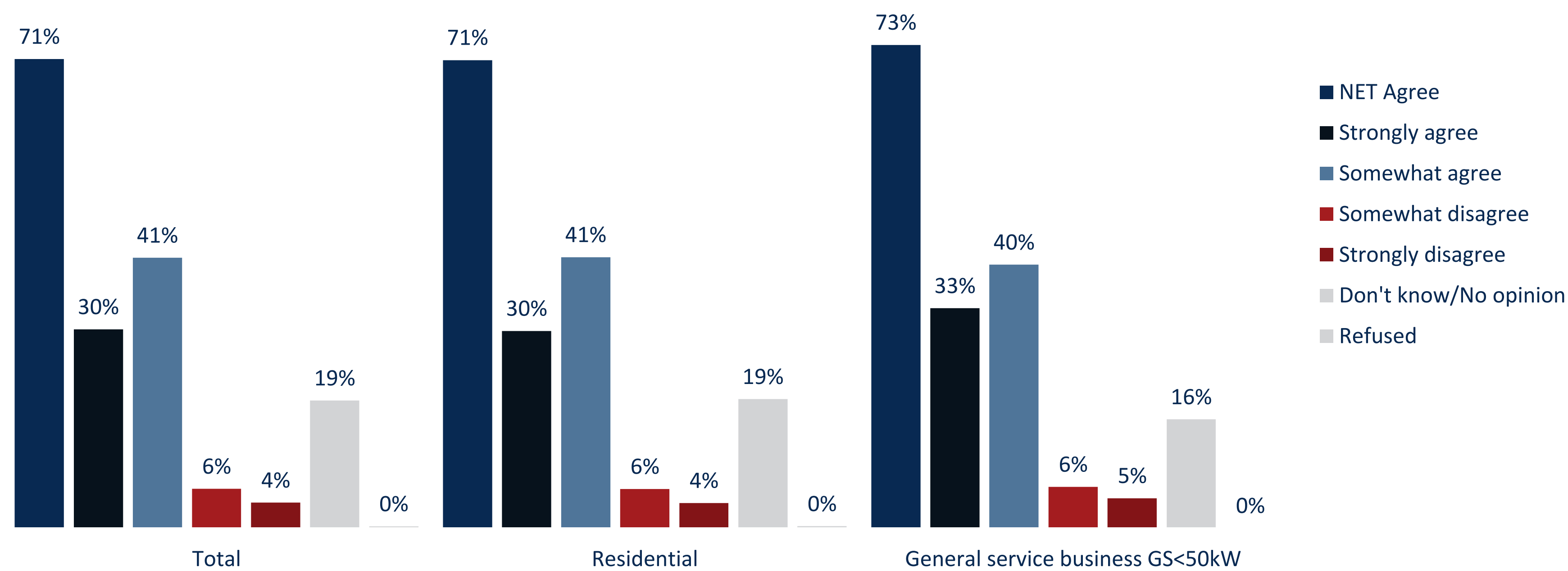
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

To what extent do you agree with "The cost of my electricity bill has a major impact [on personal finances OR bottom line of organization]"?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

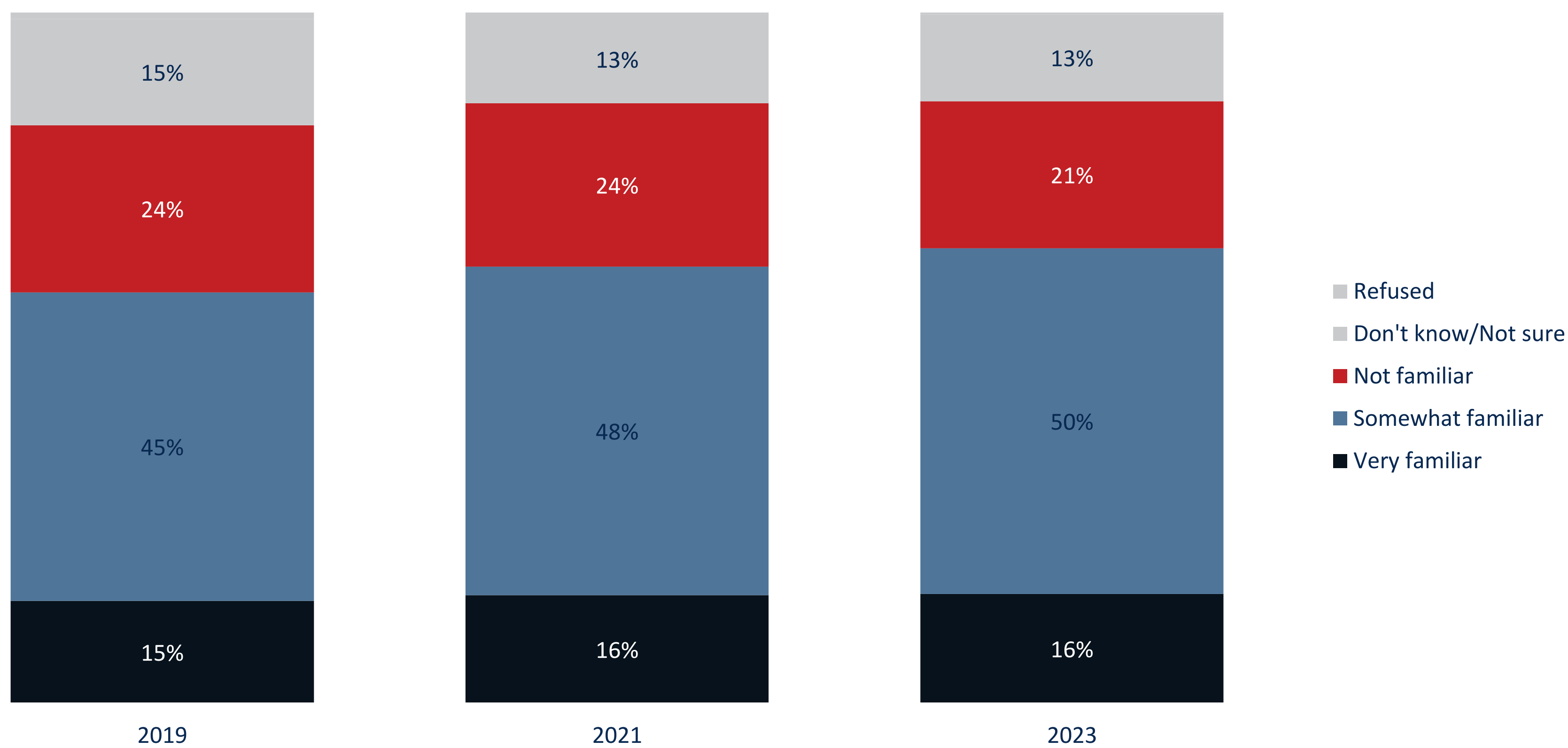
To what extent do you agree with "Customers are well served by the electricity system in Ontario"?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: ERTH Power

Core (OEB) Survey Questions – Trend over Time

How familiar are you with ERTH Power, which operates the electricity distribution system in your community?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

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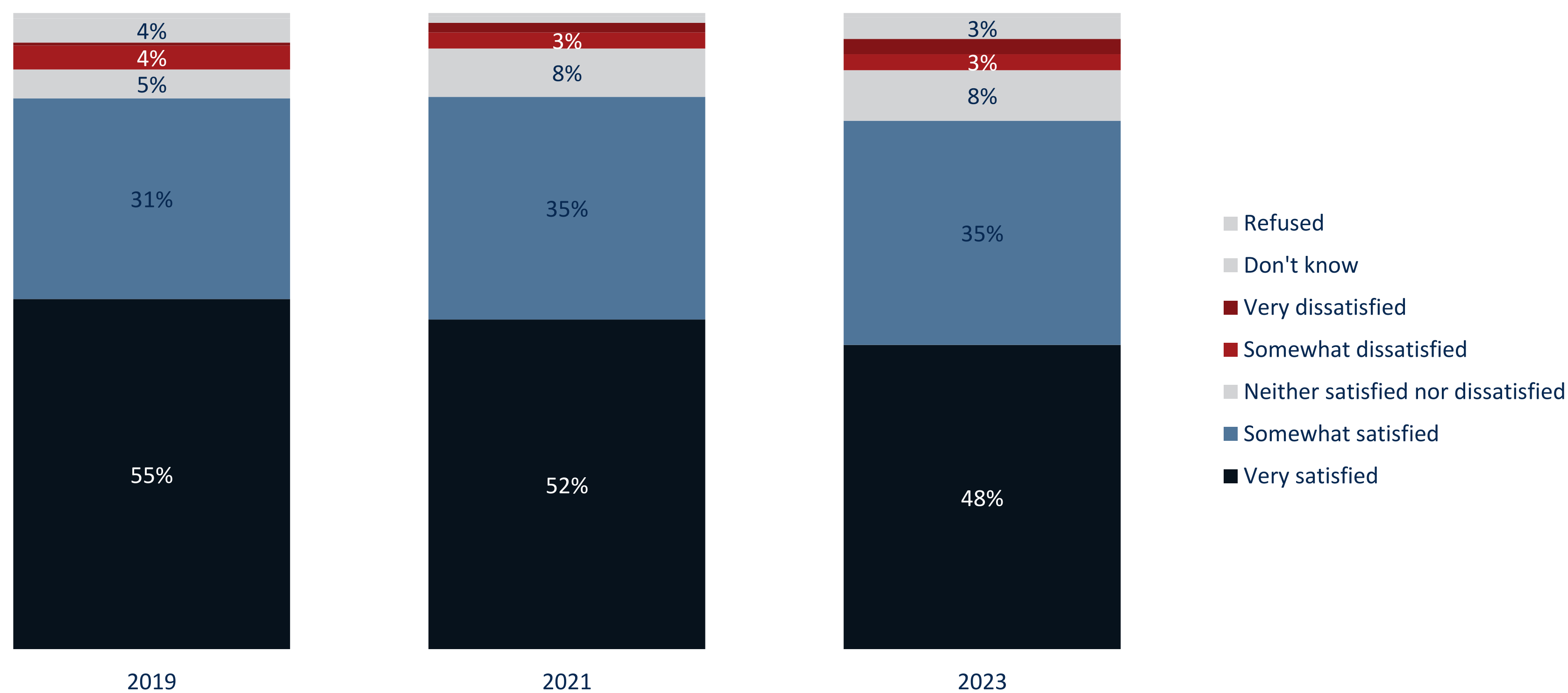
Thinking specifically about the services provided to you and your community by ERTH Power, OVERALL, how satisfied are you with the services that you receive?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

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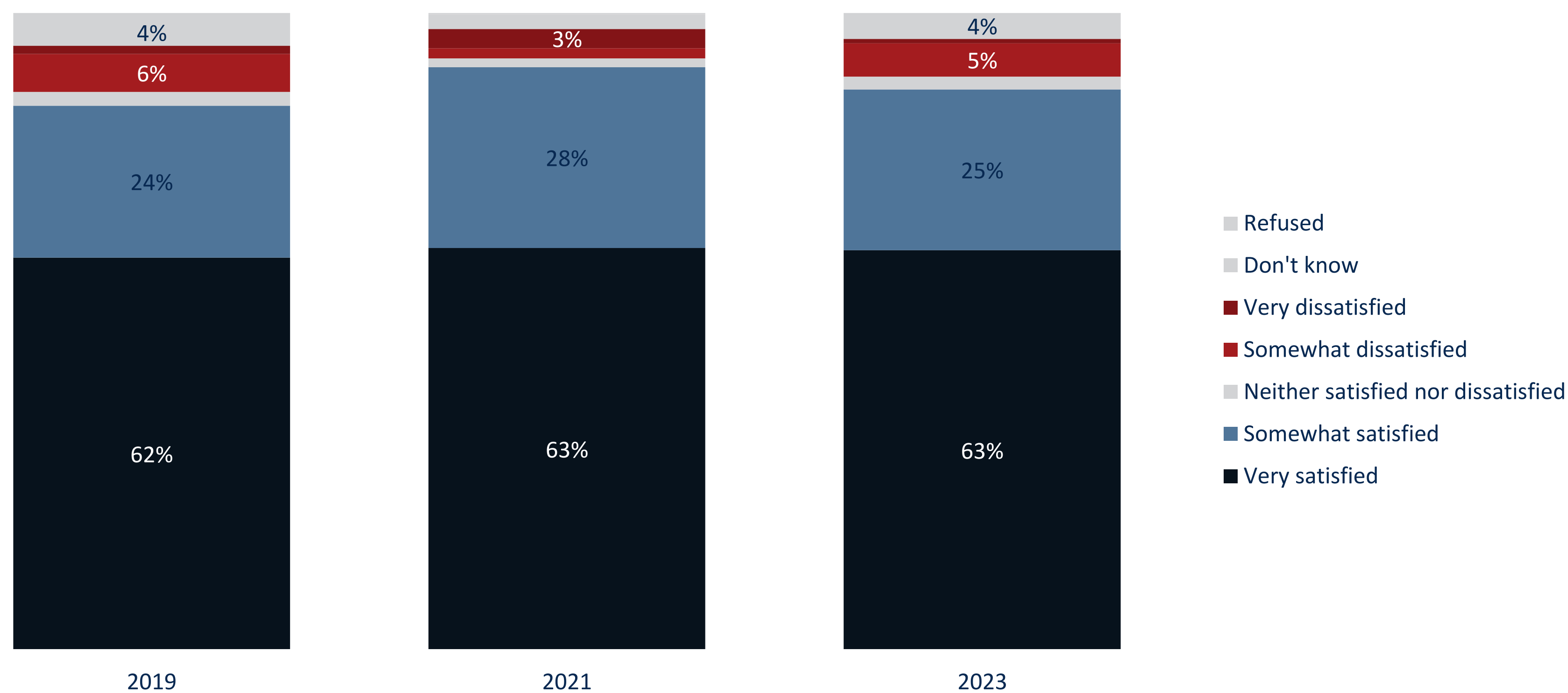
How satisfied are you with the electrical service that you receive from ERTH Power - based on the RELIABILITY of your electrical service as judged by the number of outages you experience?



Weight: Aggregate weight for LDC based on customer_type
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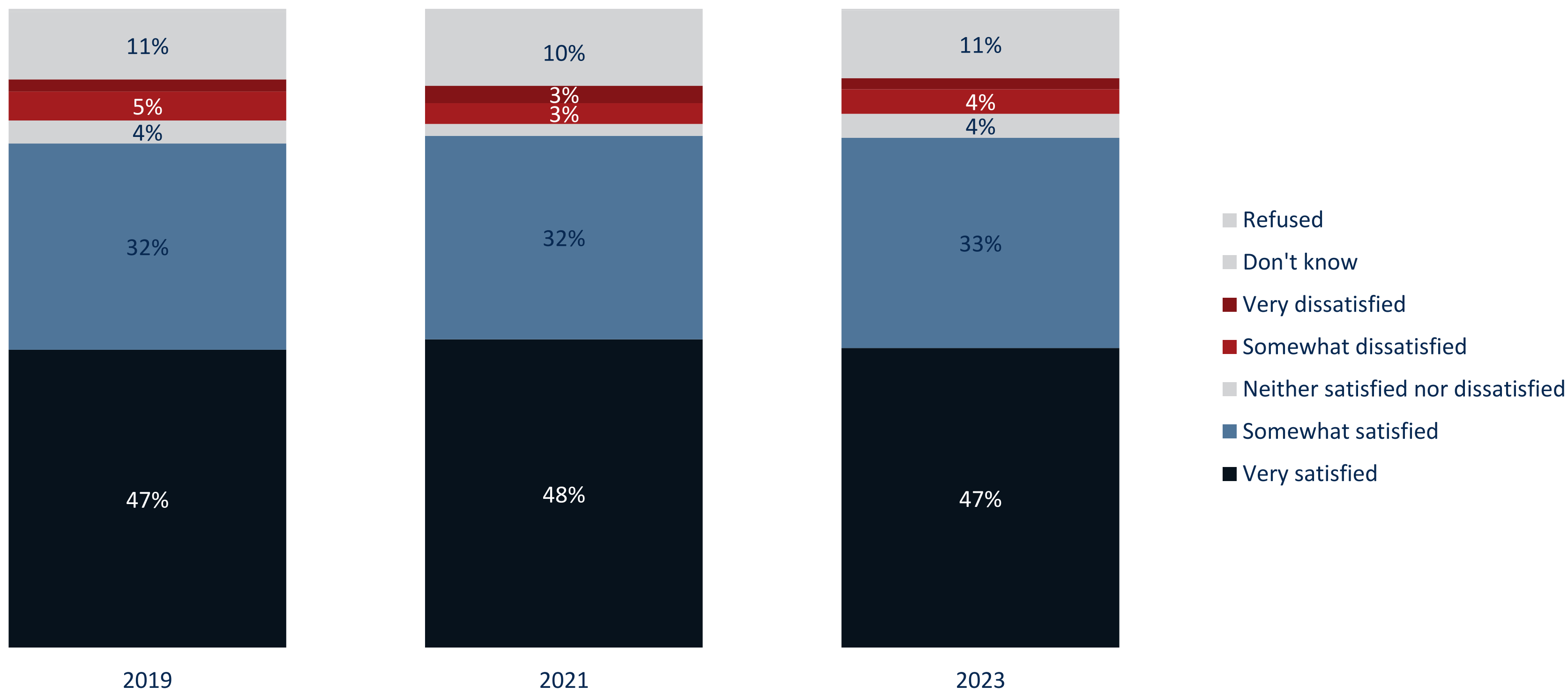
How satisfied are you with the electrical service that you receive from ERTH Power - based on the amount of TIME IT TAKES TO RESTORE POWER when outages occur?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

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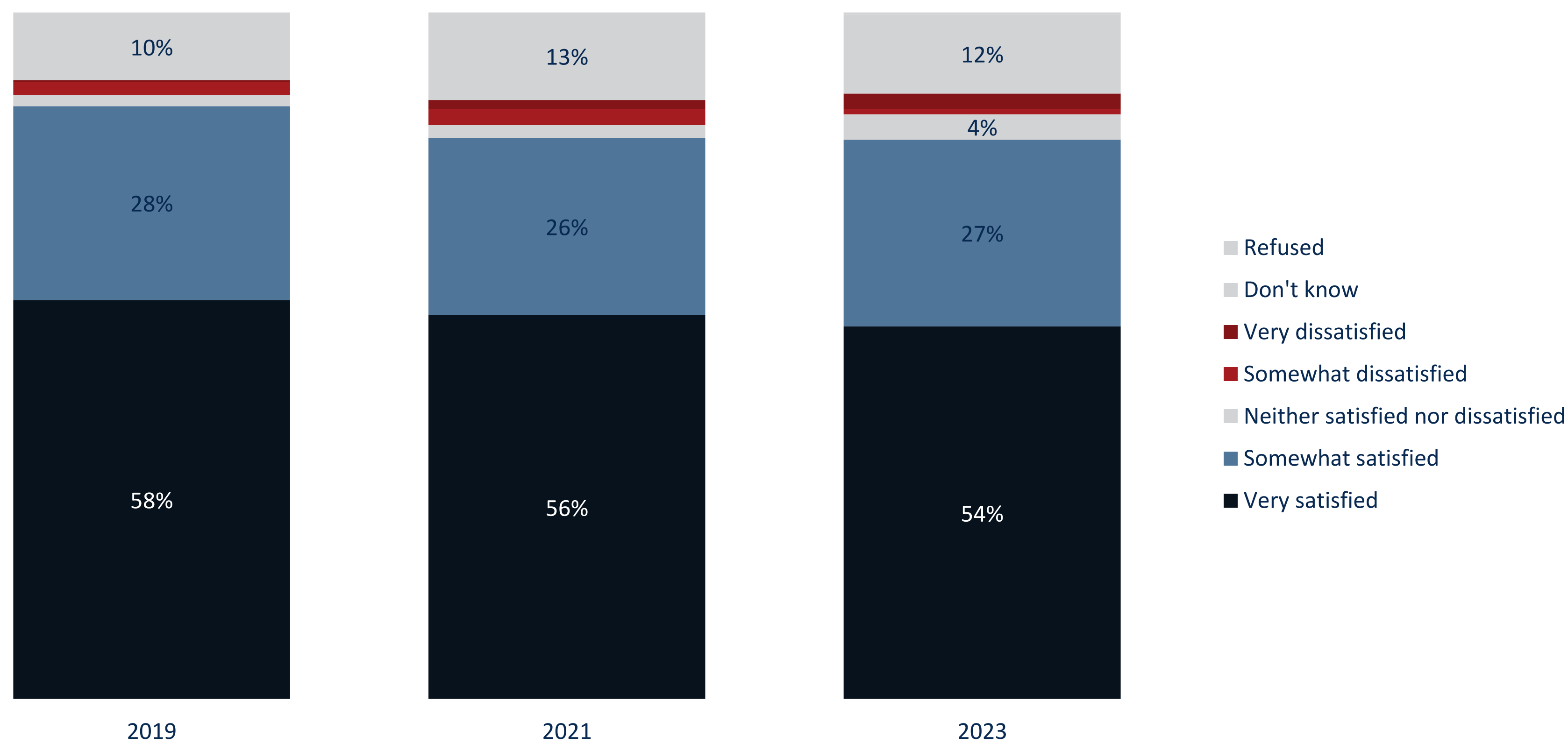
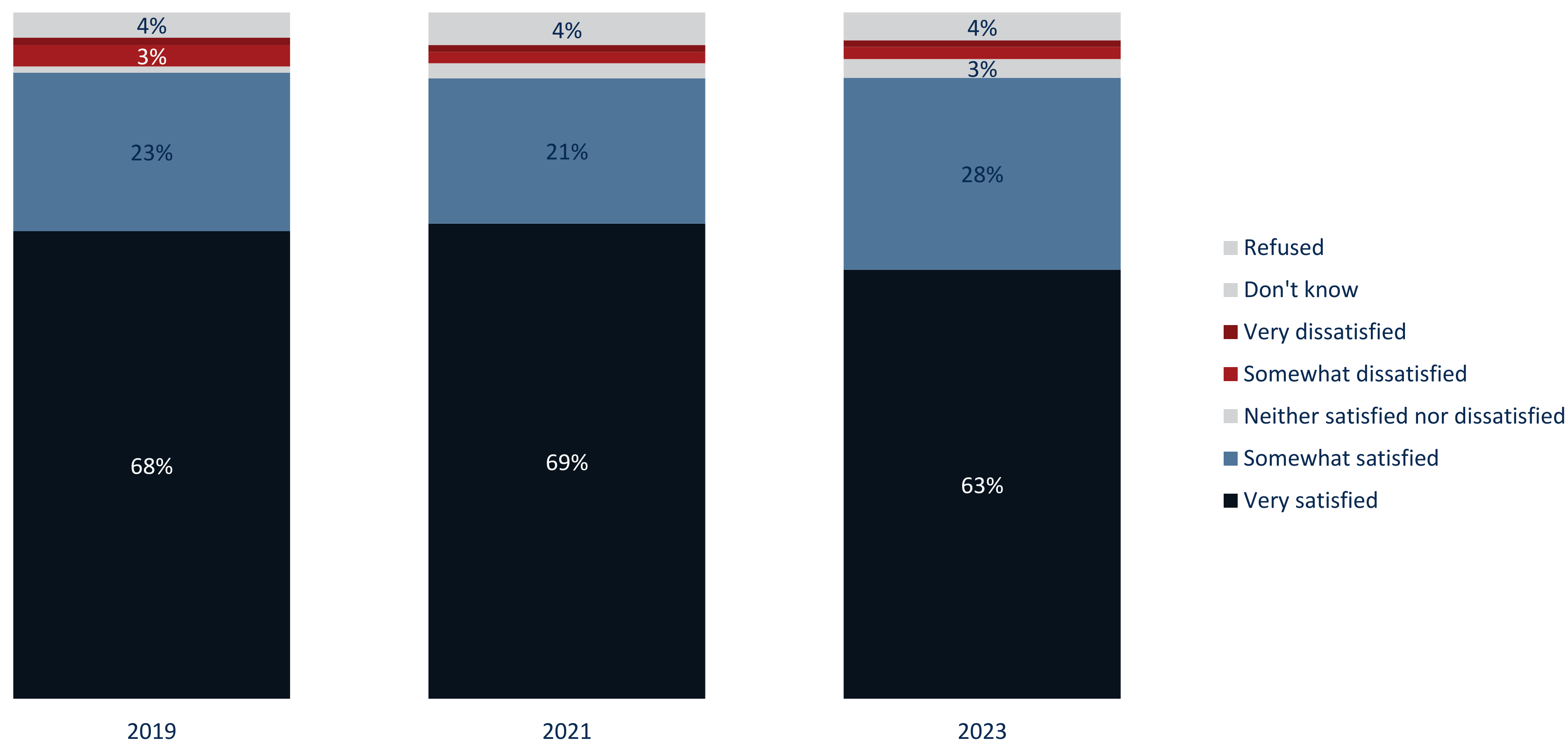


Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

How satisfied are you with the bills that you receive from ERTH Power - based on them providing CONVENIENT OPTIONS TO RECEIVE AND PAY BILLS?



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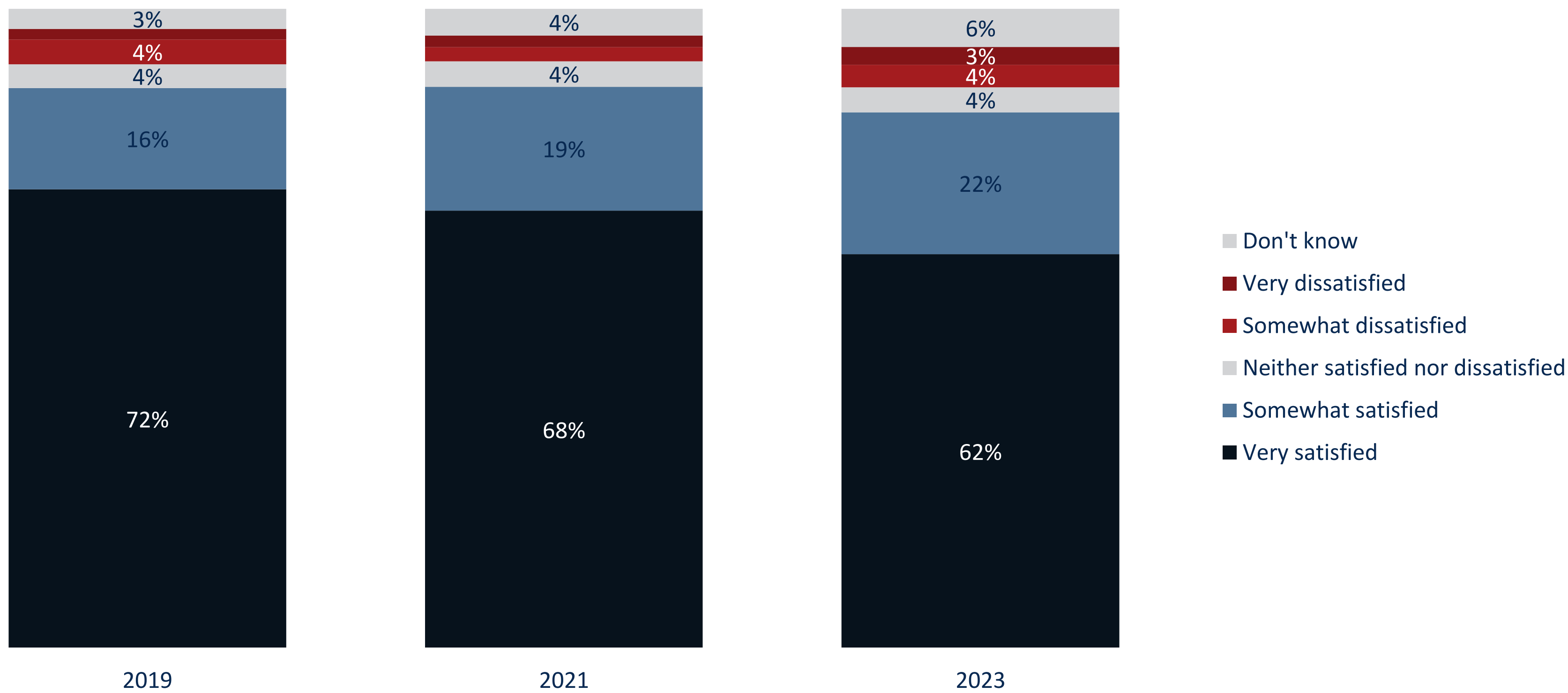

Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power
Note: Base excludes those who indicated that they had not contacted customer service, thus could not provide an assessment

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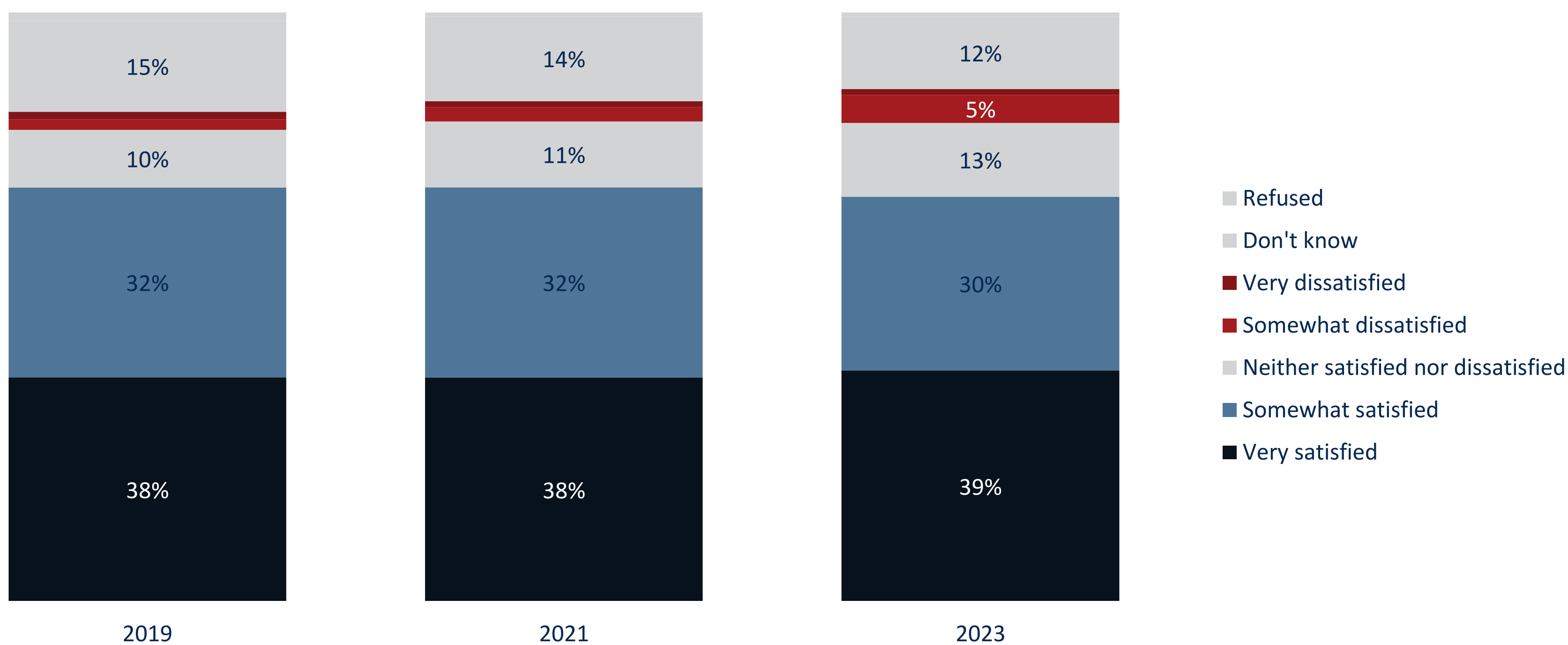

Weight: Aggregate weight for LDC based on customer_type
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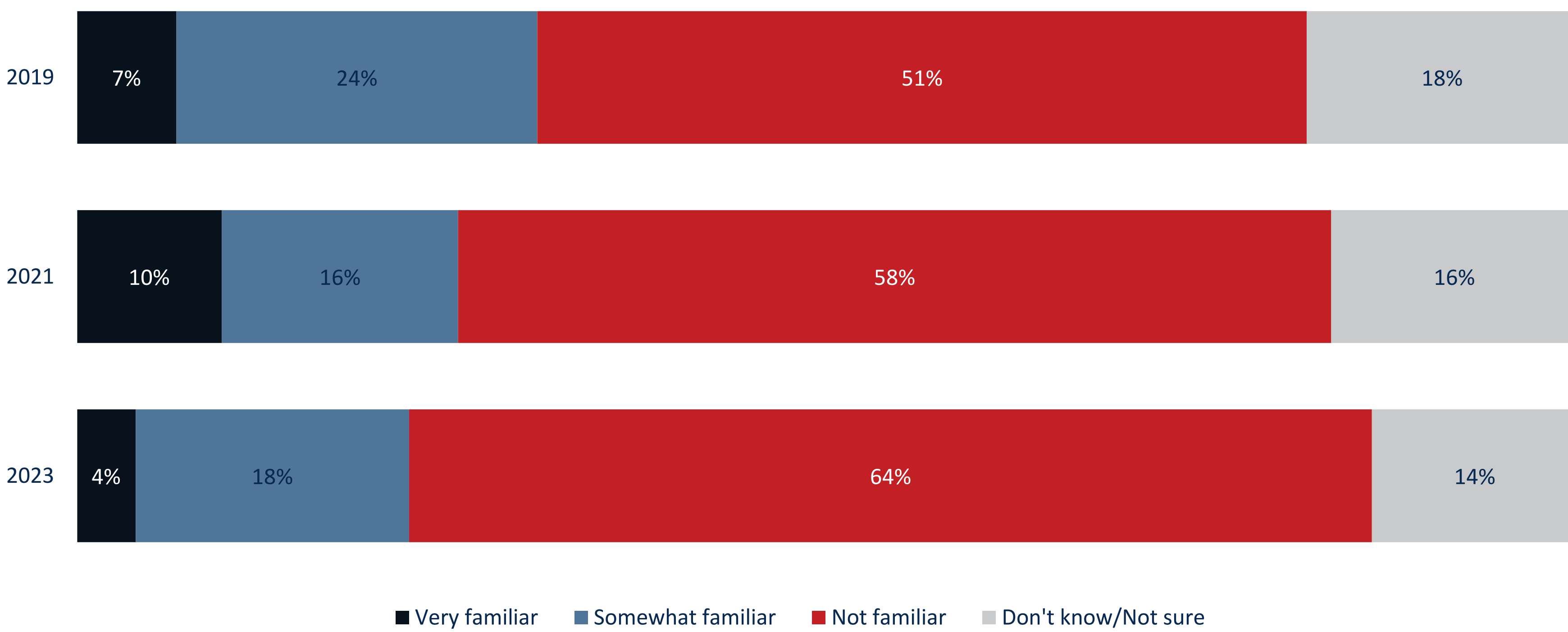

Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

ADVANIS
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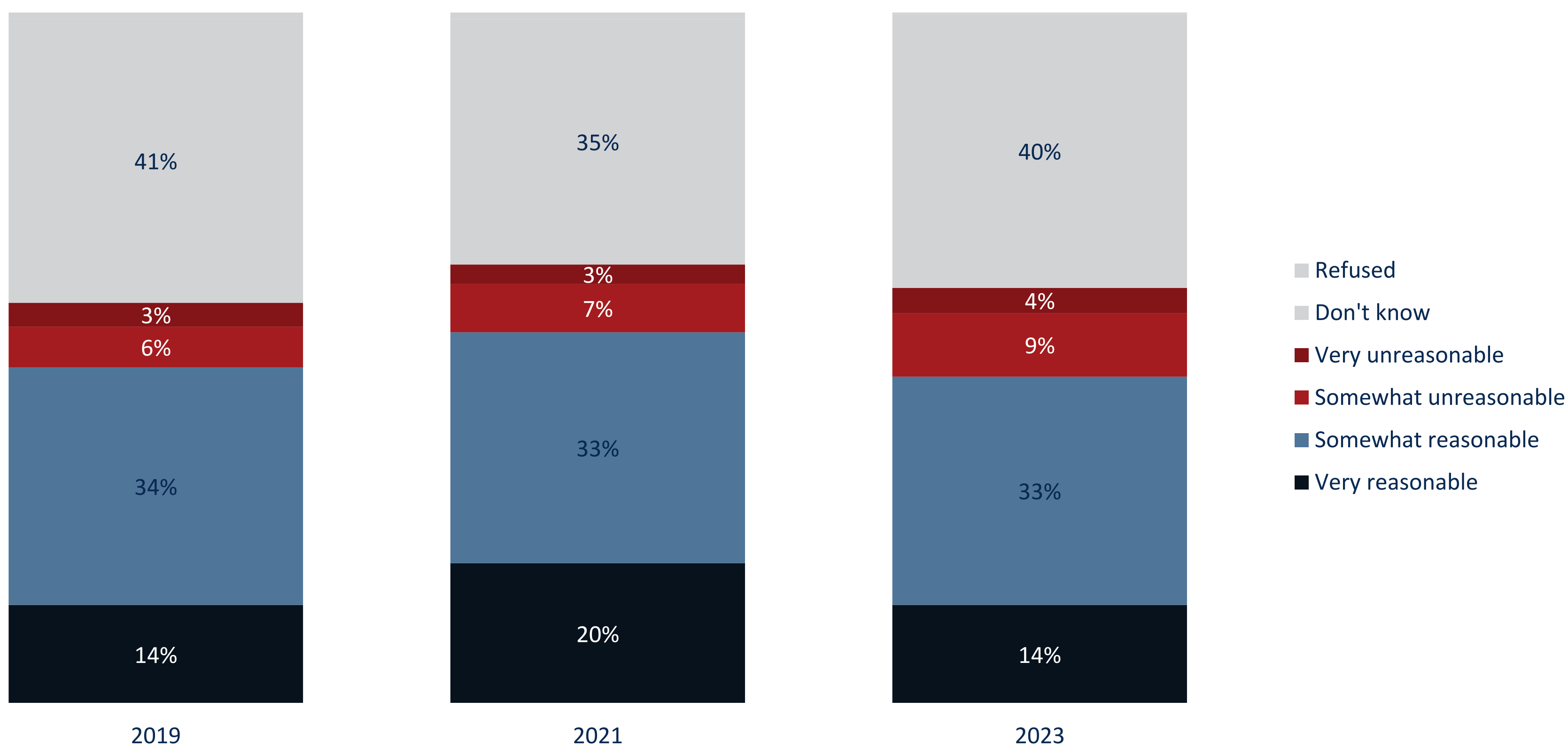

Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

ADVANIS
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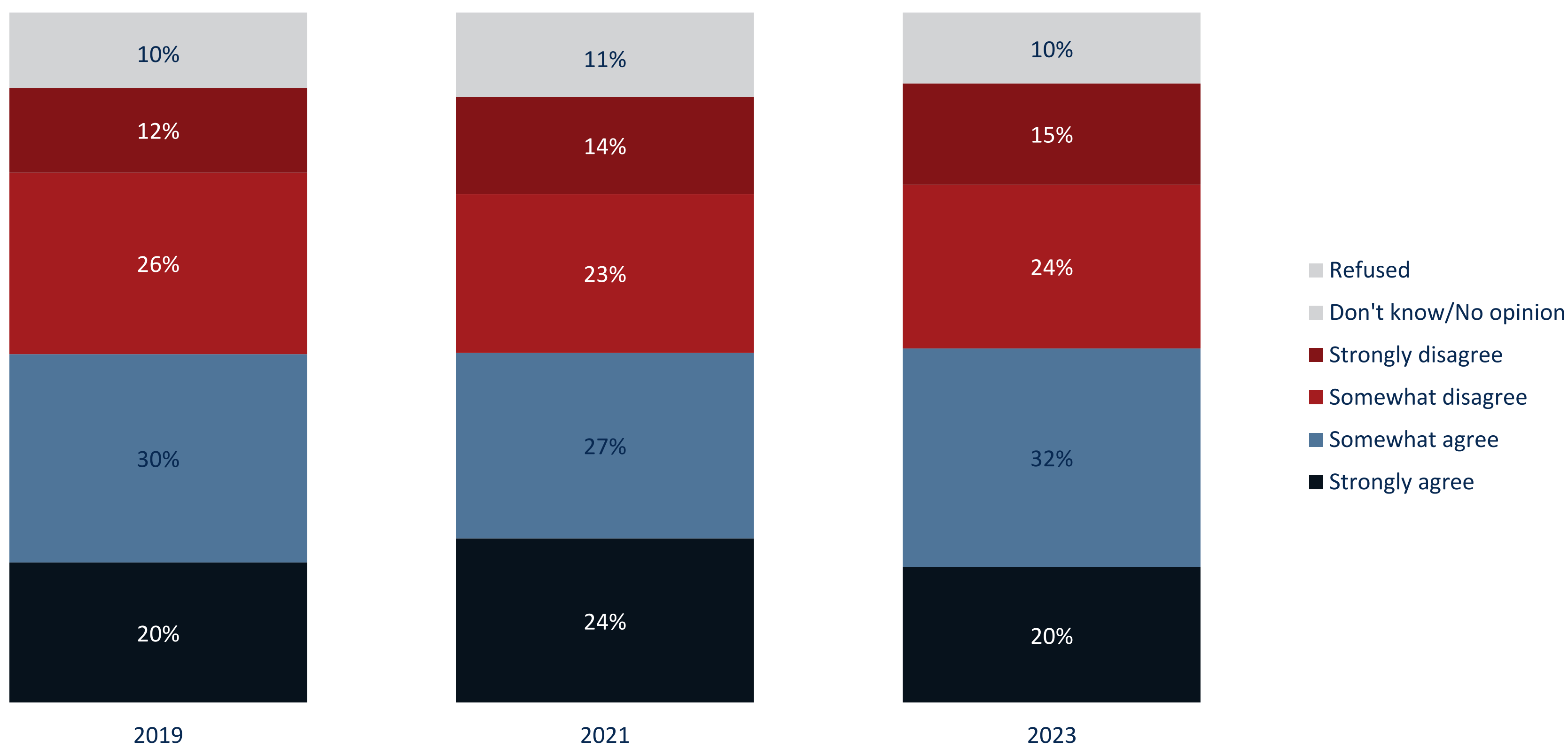
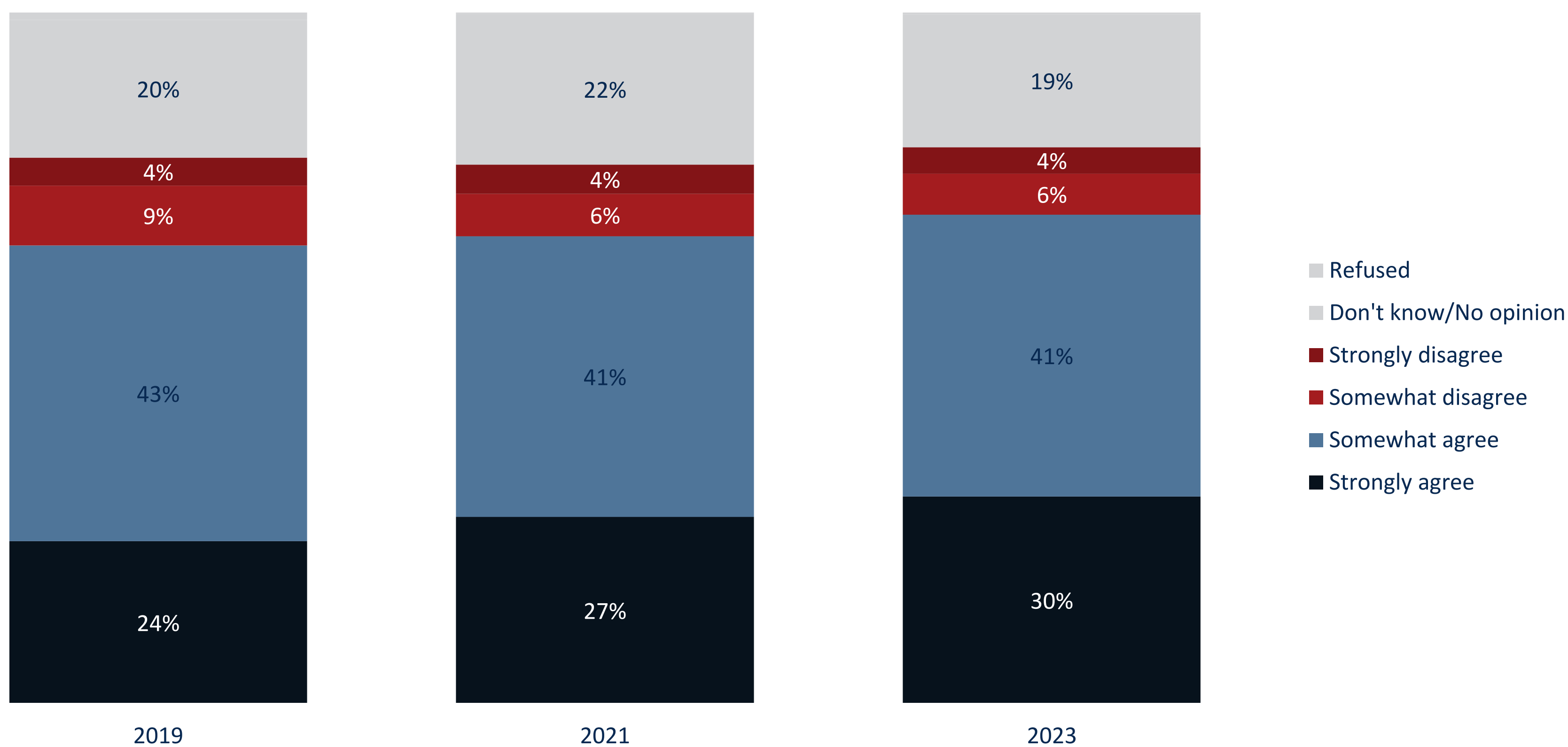
To what extent do you agree with "The cost of my electricity bill has a major impact [on personal finances OR bottom line of organization]"?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

ADVANIS *Confidential*

To what extent do you agree with "Customers are well served by the electricity system in Ontario"?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: ERTH Power

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Methodology

Methodology Summary

Commissioned by	ERTH Power Inc.
Sample size	403 randomly selected customers
Margin of error	±4.8 percentage points, 19 times out of 20
Survey mode	Random telephone survey of customer base, CATI data collection
Survey sample	Residential and GS <50kWh customer lists provided by ERTH Power
Time of calling	4PM-9PM Weekdays, 10AM-5PM Saturdays, scheduled callbacks
In-field dates	January 9-February 16, 2023
Language	English only
Survey author	Innovative Research/Electricity Distributors Association
Question Order	Core (OEB) questions then LDC-specific questions
Question Wording	Questions shown in report largely as asked; exact questionnaire available upon request
Survey Company	Advanis Gary.Offenberger@advanis.net

Methodology Details (1/4)

Target Respondents

The respondents of the survey were Ontario residents who are the primary bill payer or share the responsibility if residential or the person in-charge of managing the electricity bill at the organization if general service, and who resided within one of LDC's service territory(ies). Service territories were determined based on customer lists provided by the LDC.

Sample Size and Statistical Reliability

The final total completed surveys by LDC, and the associated margin of error for each, are shown below.

All margins of error are shown at a 95% confidence level.

- E.g., the margin of error associated with a sample size of 400 for a large (infinite) population is ±4.9 percentage points, 19 times out of 20.

Since each LDC has a finite population, we used the specific population sizes (i.e., the number of sample records received from each LDC) in the calculation of margin of error. Doing so is more accurate, and results in a narrower margin of error than if we simply assumed large (infinite) population for each.

Sample sizes were set according to the *LDC Customer Satisfaction Survey: Methodology & Survey Implementation Guide*, prepared for the Electrical Distributors Association (April 19, 2016 revision):

Where possible, sample size of n=400.
Distributors with 3000 to 4999 customers (residential + GS<50), n=300
Distributors with <3000 customers (residential + GS<50), n=200

Methodology Details (2/4)

Sampling Methodology

Advanis was provided sample lists from each LDC. Customer lists included all basic information required such as name, telephone number, region (where applicable), customer type (residential or GS<50), LDC fee, Annual or Monthly consumption values. Redhead then calculated which quartile group each resident belonged to by evenly dividing them into four groups within each region and customer type. These quartiles were calculated based on annual consumption value.

To minimize low response:

- Sample was loaded in batches to ensure the sample was fully utilized before moving onto fresh sample records;
- Calls were made between the hours of 4pm and 9pm ET; and
- Call backs were scheduled and honored between the hours of 9am and 9pm ET.

Sample Cleaning

Redhead cleaned the customer lists individually once received from each LDC to ensure the customer list counts reflected actual individual records that could be called. The following steps were taken during sample cleaning.

- All records with no phone numbers were removed.
- All phone numbers were checked to see if they were valid numbers (i.e., 10 digits, all numerical, etc.) and any bad cases were removed.
- When duplicates were detected based on phone number, the average of the consumption value was calculated and kept for one consolidated record. All others were removed.
- Residential and GS<50KW were separated into their own lists to be loaded and managed separately in the calling system.

Regions within each customer list were given a numerical value to be used for calling quotas.

Methodology Details (3/4)

Questionnaire

The survey instrument was provided by the Electricity Distributors Association (EDA) developed in conjunction with Innovative Research. The survey consisted of an introduction, overall satisfaction, power quality and reliability, billing and payment, customer service experience, communications, price, optional deeper dive questions, and final personal finance / sector mood measures. Additional questions were provided individually by some LDCs. These questions are not required as part of the survey and, as outlined in the methodology guideline, were asked after all the standard and required questions.

Data Collection

Computer aided telephone interviews (CATI) were conducted from **January 9-February 16, 2023.**

Quality Control

- Advanis trained its interviewers to understand the study's objectives;
- Detailed call records are kept by the automated CATI system, and are supplemented by output files to SPSS for productivity analysis (i.e., not subject to human error);
- The survey was soft launched in LDCs that had the most available sample, and the data was then checked before calling began in full for each;
- 100% of all surveys are digitally recorded for potential review (see next bullet);
- Advanis' Quality Assurance team listened to the actual recordings of five-ten percent of completed surveys and compared the responses to those entered by the interviewer to ensure that responses from respondents are properly recorded;
- Team Supervisors conduct regular more formal evaluations with each interviewer, in addition to nightly monitoring of each interviewer on their team;
- Project Managers closely monitored the progress of data collection, including call record dispositions;
- All SPSS code is reviewed by a more senior researcher;
- All report output is reviewed by a more senior researcher; and
- All values in the report are reviewed by another team member to ensure accuracy.

Methodology Details (4/4)

Analysis of Findings & Data Weighting

Results were weighted to match the proportion of low volume rate class records as provided to Advanis after cleaning of the sample file. Where a region flag was also provided, results were weighted to the low volume rate class within each region and regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

The Customer Satisfaction index scores have been highlighted and were calculated as described below, based on instructions in the Survey Methodology Guidelines. The "response values" referenced in the description below were also determined and provided by the survey authors.

Data analysis and cross-tabulation have been conducted using SPSS and Advanis' proprietary Online Reporting Environment software.

This **index score** is calculated using the following process:

Step 1: Weight data to n=400 with each low volume rate class proportionate to its share of LDC customer base.

Step 2: Rescale the index score variables onto the 0 to 1 scale as indicated by the response values detailed below.

Step 3: The average result of the questions asked for each OEB topic and the overall satisfaction score will be added together[3].

	B5
+	**[C6+C7+C8]** divided by 3
+	**[D9+D10]** divided by 2
+	**E11**
+	**F12**
+	**G14**
=	**Total cumulative scores**

Step 4: The total cumulative score from Step 2 will be divided by 6 to generate the **Customer Satisfaction Index Score** (bound between 0-1).

The chart on the following page illustrates how the **Customer Satisfaction Index Score** will be calculated.

As noted above, LDCs without a region flag were weighted to their low volume rate class proportion based on the cleaned sample file. LDCs with a region flag were weighted to their low volume rate class proportion within each region based on the cleaned sample file, and then regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

Specific values of the number of sample records, estimated population proportions, and final weighted sample counts within LDC are provided on the next slide.
The sum of the regional population proportions within an LDC may not equal 100% due to rounding.

Methodology Tables (1/2)

Margin of error

LDC	Clean Customer Records from LDC	Completed Surveys	Sample Size as % of Customer list	Margin of Error @ 95% confidence level
ERTH Power	21,863	403	1.84%	+/- 4.8%

* Since each LDC has a finite population, we used the specific population sizes (i.e., the number of sample records received from each LDC) in the calculation of margin of error. Doing so is more accurate, and results in a narrower margin of error than if we simply assumed large (infinite) population for each.

Methodology Tables (2/2)

Sample weighting

ERTH Power						
Regions Flagged in Sample	Low Volume Rate Class	Sample Received (Cleaned, Deduplicated)	Rate Class Proportion	Estimated Customer Proportion	Weighted Sample Count	Unweighted Sample Count
Aylmer	Residential	2,592	92%	13%	48	47
	General Service < 50 kW	235	8%		4	5
Beachville	Residential	329	94%	2%	6	6
	General Service < 50 kW	21	6%		0	1
Belmont	Residential	835	94%	4%	15	15
	General Service < 50 kW	51	6%		1	1
Burgessville	Residential	158	89%	1%	3	3
	General Service < 50 kW	20	11%		0	0
Clinton	Residential	1,303	90%	7%	24	22
	General Service < 50 kW	148	10%		3	3
Embro	Residential	335	92%	2%	6	6
	General Service < 50 kW	29	8%		1	1
Goderich	Residential	3,226	91%	16%	59	63
	General Service < 50 kW	321	9%		6	6
Ingersoll	Residential	4,832	94%	23%	89	84
	General Service < 50 kW	293	6%		5	6
Norwich	Residential	1,135	94%	6%	21	23
	General Service < 50 kW	73	6%		1	1
Otterville	Residential	439	93%	2%	8	8
	General Service < 50 kW	31	7%		0	0
Port Stanley	Residential	1,439	94%	7%	27	26
	General Service < 50 kW	88	6%		2	2
Tavistock	Residential	1,218	95%	6%	22	22
	General Service < 50 kW	70	5%		1	2
Thamesford	Residential	530	93%	3%	10	10
	General Service < 50 kW	38	7%		1	1
West Perth	Residential	1,893	91%	9%	35	36
	General Service < 50 kW	181	9%		3	3
TOTAL	**Residential**	**20,264**	**93%**	**100%**	**374**	**371**
	General Service < 50 kW	**1599**	**7%**		**29**	**32**
					402	**403**

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APPENDIX B. Regional Planning: RIP Report 2022 London Area

London Area
Regional Infrastructure Plan

August 12, 2022

hydro one

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Prepared and supported by:

Company
Entegrus Power Lines Inc.
ERTH Power Inc.
Hydro One Networks Inc. (Distribution)
London Hydro Inc.
Tillsonburg Hydro Inc.
Independent Electricity System Operator
Hydro One Networks Inc. (Lead Transmitter)

Disclaimer

This Regional Infrastructure Plan (“RIP”) report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the RIP report (“the Other Third Parties”), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

Executive Summary

This Regional Infrastructure Plan (“RIP”) was prepared by Hydro One with support from the RIP Study Team in accordance to the Ontario Transmission System Code requirements. It identifies investments in transmission facilities, distribution facilities, or both, that should be developed and implemented to meet the electricity infrastructure needs within the London Area.

The participants of the Regional Infrastructure Plan (“RIP”) Study Team included members from the following organizations:

- Entegrus Power Lines Inc.
- ERTH Power Inc.
- Hydro One Networks Inc. (Distribution)
- London Hydro Inc
- Tillsonburg Hydro Inc.
- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of the London Area regional planning process, which follows the completion of the London Area Needs Assessment in May 2020 [5] and the Greater London Sub-region Restoration Local Planning Report in October 2021 [6]. Scoping Assessment and Integrated Regional Resource Plan was not carried out in this cycle. This RIP provides a consolidated summary of the needs and recommended plans for London Area Region over the planning horizon (10 years). No new need had been identified at this time.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and Local Planning reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have commenced and/or completed:

- Aylmer TS transformers and low-voltage switchyard replacement project competed in 2017.
- Strathroy TS failed transformer T1 and low-voltage switchyard replacement project completed in 2019.
- Wonderland TS failed transformer T6 was replaced in 2019.
- St. Thomas TS was decommissioned and 115 kV circuit W14 re-termination work was completed in 2020.
- Sarnia Scott TS to Buchanan TS 230 kV circuits N21W/N22W tower structures refurbishment project was completed in 2021.
- Nelson TS station refurbishment project will be completed in 2022.
- Tillsonburg TS new low-voltage capacitor banks installed in 2021 and switchyard component replacement project to be completed in 2022.
- Longwood TS protection and control replacement project to be completed in 2023.
- Edgeware TS protection and control replacement project to be completed in 2024.

The major infrastructure investments planned for the London Area over the near and mid-term planning horizon are provided in the Table 1 below, along with the planned in-service dates.

TABLE 1 - RECOMMENDED PLANS FOR LONDON AREA OVER THE NEXT 10 YEARS

Need	Stations / Lines	Recommended Action Plan	In-service
Station capacity	Talbot TS	No action required	--
Greater London sub-region restoration need	W36/W37	No action required	--
End-of-life equipment replacement	Buchanan TS	Replacement of autotransformers and associated equipment	2028
	Clarke TS	Replacement of step-down transformers, associated disconnect switches, low-voltage switchyard components	2028
	Talbot TS	Replacement of step-down transformers (T3/T4), associated disconnect switches, low-voltage switchyard components	2028
	Wonderland TS	Low-voltage switchyard components replacement	2026
	M31W/ M32W (Salford Junction x Ingersoll)	London Area East Optical Ground Wire (OPGW) Infrastructure	2027
	W36/W37/W5 NL/W6NL/W2S/ N21W	London Area West Telecom Optical Ground Wire (OPGW) Infrastructure Installation	2029

The Study Team recommends Hydro One to continue with the implementation of infrastructure investments listed in Table 1 above.

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The London Area Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be triggered in advance of the five-year timeline.

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1. Introduction

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE LONDON AREA REGION BETWEEN 2021 AND 2031.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Entegrus Power Lines Inc., ERTH Power Inc., London Hydro Inc., Tillsonburg Hydro Inc., Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO"), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The London Area includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), and the City of St. Thomas. In addition, the facilities located in the London Region supply part of Norfolk County. The boundaries of the London Area are shown below in Figure 1-1.

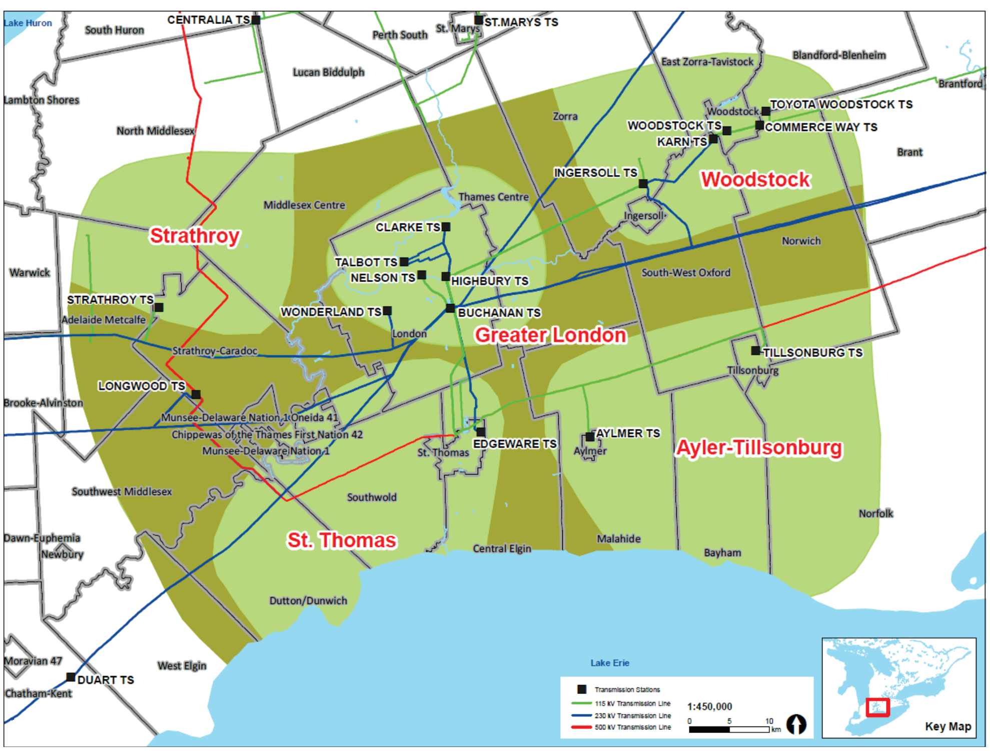


FIGURE 1-1: LONDON AREA REGION MAP

1.1. Objectives and Scope

The RIP report examines the needs in the London Area Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases i.e., Needs Assessment and Local Planning;
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment needs emerging over the near and medium term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases;
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2. Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 discusses the needs and provides the alternatives and preferred solutions.
- Section 7 provides the conclusion and next steps.

2. Regional Planning Process

2.1. Overview

Planning for the electricity system in Ontario takes place at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning focuses on assessing supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2. Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (non-wires alternatives) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO.

[1] Also referred to as Needs Screening

The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

The RIP phase is the fourth and final phase of the regional planning process and involves discussion of previously identified needs and plans, identification of any new needs that may have emerged since the start of the planning cycle, and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

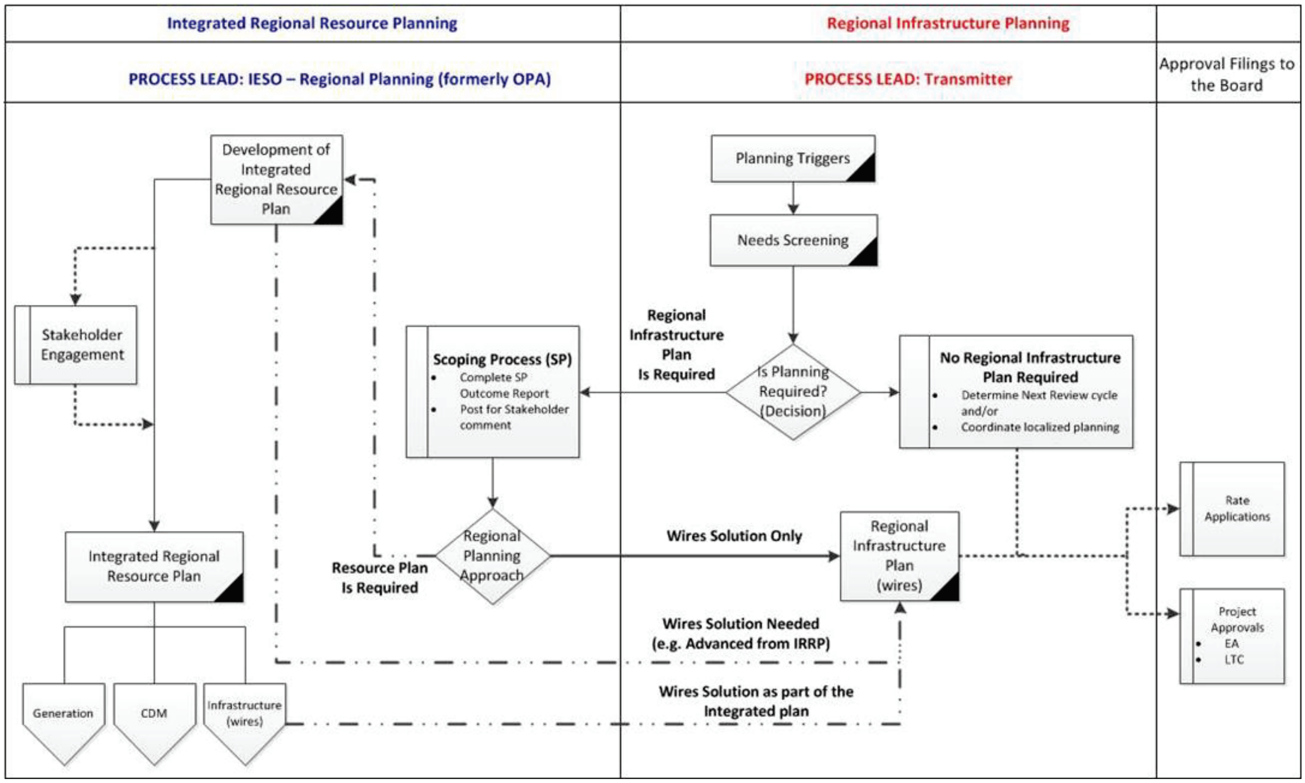


FIGURE 2-2: REGIONAL PLANNING PROCESS FLOWCHART

Upon the conclusion of Needs Assessment, the Study Team agreed that the need in the region (i.e., Greater London sub-region restoration need) was local in nature and no further regional coordination was required. Subsequently, a Local Planning report was completed to specifically address the restoration need. Therefore, Scoping Assessment and Integrated Regional Resource Plan was not carried out for London Area in this cycle.

2.3. RIP Methodology

The RIP phase consists of a four step process (see Figure 2-3) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

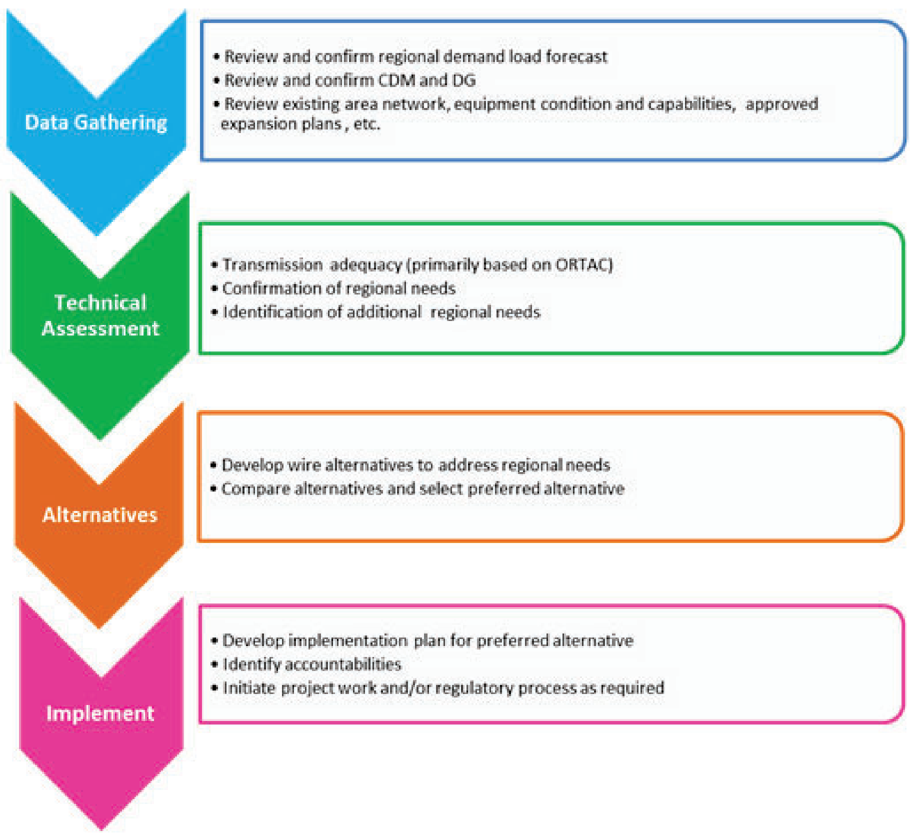


FIGURE 2-3: RIP METHODOLOGY

3. Transmission System Supplying London Area

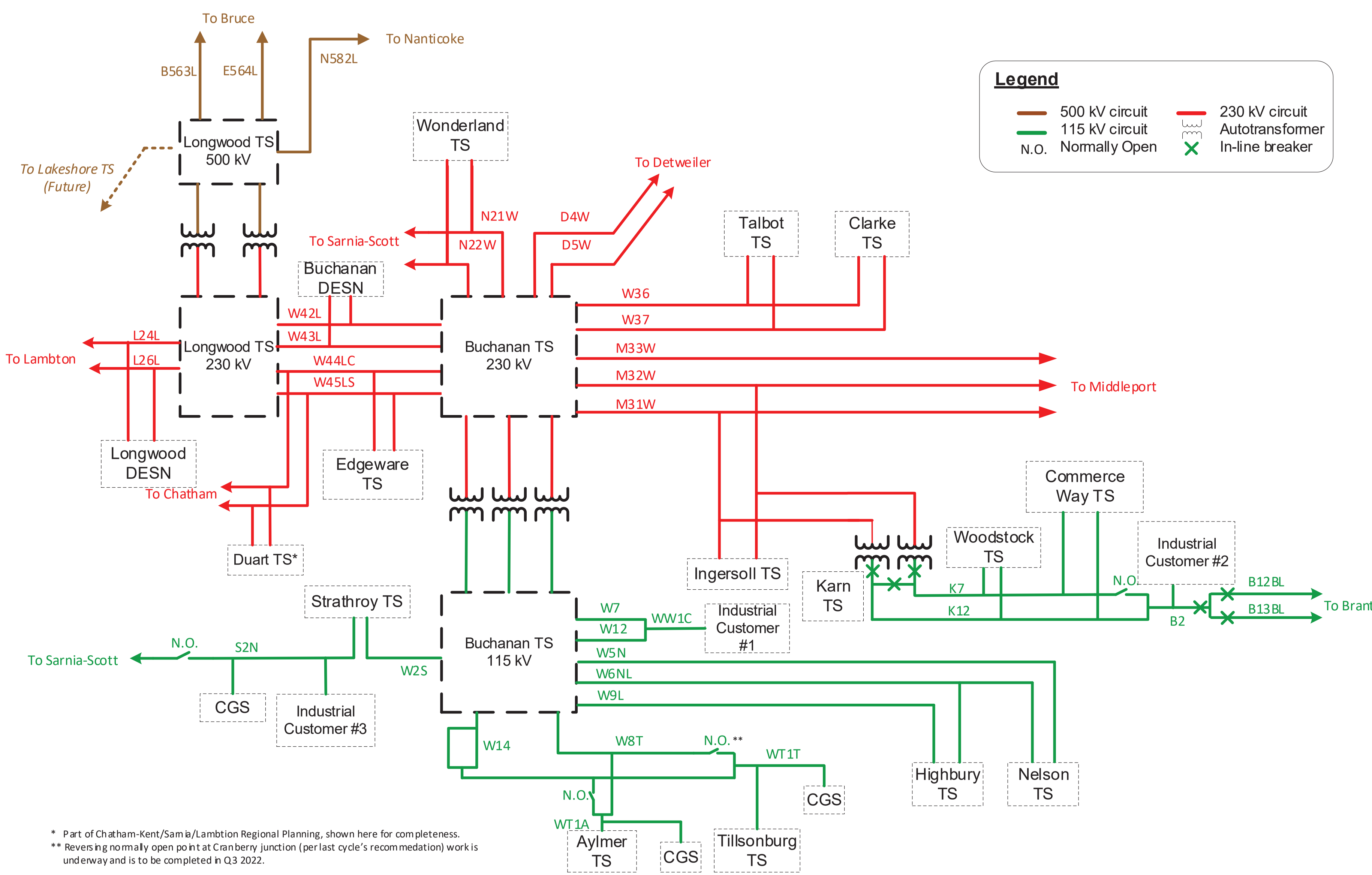
The hub of the electrical system in London Area is Longwood Transformer Station (“TS”). Longwood TS provides the single connection to the 500 kV system in this area, through which provides majority of the resources to meet the demand in the London Area and rest of southwestern Ontario. The 500 kV system is part of the bulk power system and although it is not studied as part of this RIP, it should be noted that in 2021, the IESO identified a need to expand the 500 kV bulk system to supply the load growth in the Leamington area by 2030. The IESO recommended a new 500 kV single-circuit line connecting Longwood TS and Lakeshore TS and two 500/230 kV autotransformers to be constructed at Lakeshore TS.

London Area is supplied by a network of 230 kV and 115 kV circuits which is connected to Longwood TS through five 500/230 kV autotransformers. Autotransformers at Buchanan TS and Karn TS provide the necessary 230/115 kV autotransformation. Step-down transformer stations are connected to both 230 kV and 115 kV systems to bring the power to distribution level of 27.6 kV to serve the area. There are fourteen Hydro One step-down TS’s, three transmission connected industrial load customers and three transmission connected generators in the London Area. The London Area Region summer coincident peak demand in 2021 was about 1152 MW, adjusted to extreme weather.

The existing facilities in the London Area are summarized below and depicted in the single line diagram shown in Figure 3-4:

- Fourteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerce Way TS, Edgeware TS, Highbury TS, Ingersoll TS, Longwood TS, Nelson TS, Strathroy TS, Talbot TS (two Dual Element Spot Networks, DESN 1 and DESN 2), Tillsonburg TS, Wonderland TS, and Woodstock TS.
- Three directly connected industrial customer loads are connected in the London Area: Enbridge Keyser CTS, Lafarge Woodstock CTS and Toyota Woodstock TS.
- There are three existing transmission-connected generating stations in the London Area as follows:
    - Suncor Adelaide GS is a 40 MW wind farm connected to 115 kV circuit west of Strathroy TS
    - Port Burwell GS is a 99 MW wind farm connected to 115 kV circuit near Tillsonburg TS
    - Silver Creek GS is a 10 MW solar generator connected to 115 kV circuit near Aylmer TS

Although depicted, Duart TS is not included in the London Area study and will be studied as part of the Chatham-Kent/Lambton/Sarnia (CKLS) Area Regional Planning.



* Part of Chatham-Kent/Sarnia/Lambtion Regional Planning, shown here for completeness.
** Reversing normally open point at Cranberry junction (per last cycle's recommedation) work is underway and is to be completed in Q3 2022.

FIGURE 3-4: SIMPLIFIED SINGLE LINE DIAGRAM OF THE LONDON AREA REGION'S TRANSMISSION NETWORK

4. Transmission Projects Completed and/or Underway Over the Last Ten Years

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY IN THE LONDON AREA REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Strathroy TS like-for-like replacement of 25/42 MVA 115/27.6 kV transformer T2 due to failure completed in 2012.
- Ingersoll TS like-for-like replacement of 75/125 MVA 230/27.6 kV transformers T5 & T6 that were approximately 35 years old. The transformers were identified to have a design weakness and were replaced to mitigate the risk of failures, improve restoration time and maintain system performance completed in 2012.
- Woodstock TS 50/83 MVA 115/27.6 kV transformers T1 & T2 that were approximately 50 years old and were deemed end-of-life were replace like-for-like in 2014.
- Aylmer TS transformers and low-voltage switchyard replacement project competed in 2017.
- Strathroy TS failed transformer T1 and low-voltage switchyard replacement project completed in 2019.
- Wonderland TS failed transformer T6 was replaced in 2019.
- St. Thomas TS was decommissioned and 115 kV circuit W14 re-termination work was completed in 2020.
- Sarnia Scott TS to Buchanan TS 230 kV circuits N21W/N22W tower structures refurbishment project was completed in 2021.
- Nelson TS station refurbishment project will be completed in 2022.
- Tillsonburg TS new low-voltage capacitor banks installed in 2021 and switchyard component replacement project to be completed in 2022.
- Longwood TS protection and control replacement project to be completed in 2023.
- Edgeware TS protection and control replacement project to be completed in 2024.

5. London Area Demand

5.1. Load Forecast

The electricity demand in the London Area Region is anticipated to grow at an average rate of 1% over the next ten years. The London Area Region has been historically a summer-peaking region. Figure 5-5 shows the London Area Region's summer coincident peak load forecast for the 2022 – 2031 study period (extreme weather corrected peak) developed during the RIP phase. The load forecast prepared for the RIP phase is approximately 5% lower than the Needs Assessment load forecast due to higher forecasted contributions from CDM and DG.

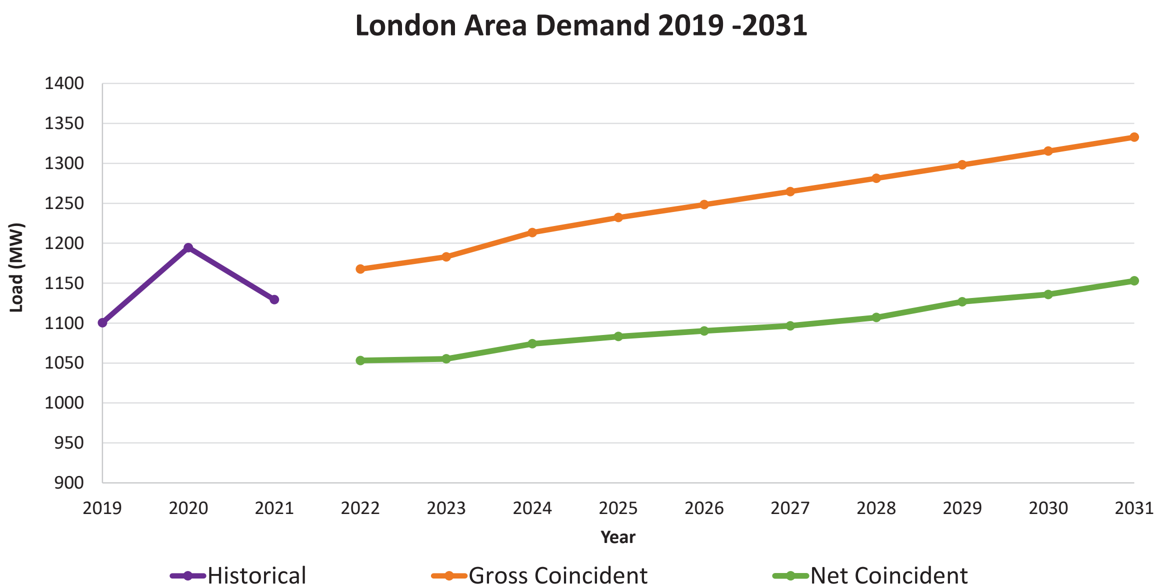


FIGURE 5-5: LONDON AREA REGION LOAD FORECAST

The load forecast shows that the region peak summer load increases from 1053 MW in 2022 to 1153 MW by 2031. The corresponding non-coincident summer peak loads increase from 1159 MW to about 1250 MW over the same period. The non-coincident and coincident net load forecasts for the individual stations in the London Area Region are given in Appendix D, Table D-1 and Table D-2.

LDCs in this region emphasized that impact of electrification have not been factored into the current RIP load forecasts. Should initiatives such as gas furnace conversion and continued electric vehicle adoption accelerate, transmission system adequacy will have to be re-assessed.

5.2. Forecast Assumptions

The following assumptions are made:

- The study period for the RIP assessment is 2022 – 2031.
- The 2021 summer station peak load is considered as a reference point and was adjusted for extreme weather impact (2.12% in 2021). Growth rates were extrapolated from LDCs' load forecasts via linear regression and are applied onto to the reference point to develop a gross load forecast.
- Distributed generation ("DG") refers to small-scale power generation connected in the distribution system which is located close to where the electricity is consumed. Both conservation & demand management ("CDM") as well as DG can reduce the amount of load that needs to be supplied and their contributions, as provided by the IESO, are directly net against the gross load forecast to develop a net load station forecast. A non-coincident version of the net load forecast was used to assess the station capacity.
- Load data for transmission-connected industrial customers in the region was assumed to be consistent with historical peak loads.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.
- Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating ("LTR"), assuming a 90% lagging power factor.

6. Regional Needs and Plans

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE LONDON AREA AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the London Area and plans to address these needs for the study period of 2022 – 2031.

Based on the gross regional non-coincident load forecast, Clarke TS is forecasted to exceed its 10-Day LTR in 2023 and Highbury TS and Tillsonburg TS will also exceed station LTR in the medium term. However, these stations are expected to be adequate to meet the net load forecast for the remainder of the study period as planned CDM targets and DG contributions continue to offset the load growth. Overall, as the net load forecast prepared for the RIP phase is approximately 5% lower than the Needs Assessment load forecast, no new need was identified.

During the development of this RIP, issue about available capacity was raised at a number of stations, most notably Strathroy TS and Tillsonburg TS. Available capacity and its allocation among LDCs are governed by OEB's Transmission System Code and are separate from the regional planning process. Hydro One Transmission will continue to engage with its customers following the conclusion of this RIP.

Table 6-2 provides a summary of the needs identified in this cycle and the corresponding sub-sections where recommendations and plans are discussed. The planned in-service dates are tentative and will be finalized closer to project commencement in coordination with impacted LDCs.

TABLE 6-2: IDENTIFIED NEAR AND MID-TERM NEEDS IN LONDON AREA REGION

No.	Need	Need Date	Section
1	Talbot TS station capacity	Today	6.1
2	Greater London sub-region restoration need	Today	6.2
3	End-of-life equipment replacement	Vary	6.3

6.1. Talbot TS

6.1.1. Sustainment Need

The existing Talbot TS comprises two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4) and supplies electricity to London Hydro customers. It is supplied by two 230 kV circuits W36 and W37. Step-down transformers T3 and T4 have been in-service from 1979 and are in poor condition and approaching end-of-life. A number of 27.6 kV breakers and protection equipment have also been identified for replacement.

6.1.2. Station Capacity Need

The station capacity for T1/T2 and T3/T4 are 113 MW and 161 MW respectively. The summer regional non-coincident peak load of the two DESNs in 2021 are 119 MW and 168 MW. According to the regional non-coincident net load forecast in the study period, Talbot TS T1/T2 DESN is expected to exceed its station capacity throughout the study period and Talbot TS T3/T4 DESN will exceed its capacity in 2029.

6.1.3. Recommendation

The station capacity need was first identified in the 2020 Needs Assessment and was primarily driven by temporary load transfer from neighbouring station (Nelson TS). As noted in Section 4, Nelson TS underwent refurbishment which includes converting the low-voltage supply from 13.8 kV to 27.6 kV. During the construction period, significant portion of the load that was originally supplied by this station was transferred to Clarke TS and Talbot TS. The newly refurbished Nelson TS was placed in-service in December 2018 and as more 27.6 kV distribution feeders becomes available in downtown London, London Hydro confirmed load will be transferred back to Nelson TS and additional transformation capacity is not required at this time.

The Study Team recommends Hydro One to proceed with like-for-like replacement of T3 and T4 at Talbot TS. Project is expected to be completed in 2028. In addition, Hydro One will look for opportunities to coordinate this project with London Hydro for the metalclad switchgear replacement.

6.2. Greater London Sub-region Restoration Need

6.2.1. Description

The 230 kV double-circuit line,W36 and W37, emanates from Buchanan TS and supplies Talbot TS (both DESNs) and Clarke TS. Should the simultaneous loss of W36/W37 occurs, all of the loads supplied by the Clarke TS and Talbot TS, which amounts to over 340 MW[2], would be interrupted by configuration. The potential load loss exceeds the ORTAC 30-minute restoration criteria.

6.2.2. Recommendation

This need was first reported in the first cycle of regional planning for the London Area Region in 2015. The 2017 IRRP working group recommended installing switching devices and feeder extensions on the distribution system. The IRRP working group also acknowledged while these measures will not fully address the restoration need, they will substantially improve the restoration capability in a cost-effective manner.

The restoration need persists in the current regional planning cycle and was further re-assessed with London Hydro via the Local Planning process. The Study Team noted a significant portion of the interrupted load could be restored by a neighbouring unaffected station, Highbury TS, if its station capacity limit is lifted. This option was not pursued further at this time as work required will be extensive and cost prohibitive. Hydro One undertook a detailed historical equipment performance review to assess the probability of common-mode failure that would lead to simultaneous loss of W36 and W37. It was concluded that the only common-mode failure that may result in the simultaneous loss of both W36/W37 is the failure of the steel poles that carry

[2] 2021 historical coincident peak load.

the two circuits and probability of this event is very low. Therefore, the Study Team recommends no action is required at this time.

6.3. End-of-Life Equipment Replacement

6.3.1. Buchanan TS

6.3.1.1. Description

Buchanan TS is a major 230/115 kV transformer station in the area that supplies load stations in London Area. The station houses three 230/115 kV auto-transformers, three 230 kV capacitor banks, one 115 kV capacitor bank and two 230/27.6 kV step-down transformers. There are sixteen 230 kV oil breakers and nine SF6 circuit breakers in the 230 kV switchyard; seventeen oil circuit and three SF6 circuit breakers in the 115 kV switchyard.

Two of the 3 auto-transformers T2 and T3 are 48 and 54 years old respectively, are in poor condition, and approaching the end of life.

6.3.1.2. Recommendation

To address poor equipment performance of deteriorating equipment, Hydro One plans to replace two 230kV autotransformers, spill containment pits, AC and DC station service equipment, as well as some obsolete protection, controls and telecom equipment.

6.3.2. Clarke TS

6.3.2.1. Description

Clarke TS is a DESN station located in the northern part of the London Area. The station is supplied by two 230 kV circuits W36 and W37. The station supplies electricity to London Hydro and Hydro One Distribution customers.

The two 230/27.6 kV 50/83 MVA transformers T3 and T4 are 55 years old, in poor condition, and approaching end of life. Some of the protection equipment is also found to be obsolete.

6.3.2.2. Recommendation

To address the assets in poor condition and end-of-life, Hydro One plans to replace step-down transformers like-for-like, associated disconnect switches, 27.6 kV switchyard components including breakers, station services, capacitors and protections. Replacement plan will be closely coordinated with affected LDCs and the expected completion date is 2028.

6.3.3. Wonderland TS

6.3.3.1. Description

Wonderland TS is a DESN station located in the western part of the London Area. The station is supplied by two 230 kV circuits N21W and N22W. The station supplies electricity to London Hydro and Hydro One Distribution customers.

The Wonderland T5/T6 DESN facility was originally built in the 1960s and its equipment is degrading in condition. The 50/83 MVA T6 power transformer was replaced in 2004 due to failure. The companion transformer, T5, failed in July 2019 and was subsequently replaced. The existing air insulated 27.6 kV switchgear, majority of which are original installations have reached end-of-life due to deteriorated condition and has limited availability of parts for ongoing support and maintenance. All site protection and control equipment, consisting of first generation electro-mechanical relaying are deemed end-of-life, obsolete and require replacement. During the early project development phase, London Hydro and Hydro One Distribution were consulted to assess if there is a capacity need to replace the 50/83 MVA transformers with 75/125 MVA and it was concluded there is no such need at the time.

6.3.3.2. Recommendation

To address the end-of-life need, Hydro One plans to replace the Wonderland 27.6 kV switchyard. Replacement plan will be closely coordinated with affected LDCs and the expected completion date is 2026.

6.3.4. London Area East OPGW Infrastructure

6.3.4.1. Description

M31W and M32W are 230 kV network circuits that connect Buchanan TS and Middleport Port TS. Ingersoll TS and Karn TS are tapped off M31W/M32W at Salford Junction. High voltage 230/115 kV autotransformers are located at Karn TS provide the necessary transformation from the 230 kV system to the Woodstock and Commerce Way 115 kV system.

6.3.4.2. Recommendation

To improve the reliability of power system telecom network, Hydro One plans to install 9km of OPGW fibre from Salford Junction to Ingersoll TS and remove the existing licensed microwave link connects Ingersoll TS to Buchanan TS. Project is expected to be completed in 2027.

6.3.5. London Area West OPGW Infrastructure

6.3.5.1. Description

Several transmission lines in the London area that emanate from Buchanan TS currently rely on leased legacy dedicated metallic cable infrastructure for DC remote trip protections. These include 230kV circuits W36/W37 that connect to Talbot TS and Clarke TS, 115 kV circuits W5N/W6NL that connect to Nelson TS and Highbury TS, 115 kV circuit W2S that connects to Strathroy TS and 230kV circuit N21W connecting to Sarnia Scott TS.

6.3.5.2. Recommendation

To improve the reliability of power system telecom network, Hydro One plans to establish a geographically diverse and fully redundant fibre optic network for protection and SCADA applications. A combination of Hydro One's existing and new OPGW-based fibre and two leased third-party fibre links would be utilized. The existing metallic cable will be removed and the project is expected to be completed in 2029.

7. Conclusions and Next Steps

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE LONDON AREA REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 7-3 below are all end of life needs, along with their planned in-service date. The planned in-service dates are tentative and will be finalized closer to project commencement in coordination with impacted LDCs.

TABLE 7-3: RECOMMENDED PLANS IN LONDON AREA REGION OVER THE NEXT 10 YEARS

Stations / Lines	Scope	In-service
Buchanan TS	Replacement of autotransformers and associated equipment	2028
Clarke TS	Replacement of step-down transformers, associated disconnect switches, low-voltage switchyard components	2028
Talbot TS	Replacement of step-down transformers (T3/T4), associated disconnect switches, low-voltage switchyard components	2028
Wonderland TS	Low-voltage switchyard components replacement	2026
M31W/ M32W (Salford Junction x Ingersoll)	London Area East OPGW Infrastructure	2027
W36/W37/W5 NL/W6NL/W2S/ N21W	London Area West Telecom OPGW Infrastructure Installation	2029

The Study Team recommends Hydro One to continue with the implementation of infrastructure investments listed in Table 7-3.

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be triggered in advance of the five-year timeline.

References

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[3] Woodstock Sub-region Restoration Local Planning [2017]
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[5] London Area Needs Assessment [2020]
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/london/Documents/Needs-Assessment-Report-London-2020.pdf

[6] Greater London Sub-region Restoration Local Planning [2021]
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Appendix A. Stations in the London Area Region

Station	Voltage (kV)	Supply Circuits
Aylmer TS	115/27.6	W8T
Buchanan TS	230/27.6	W42L/W43L
Clarke TS	230/27.6	W36/W37
Commerce Way TS	115/27.6	K7/K12
Edgeware TS	230/27.6	W44LC/W45LC
Highbury TS	115/27.6	W6NL/W9L
Ingersoll TS	230/27.6	M31W/M32W
Longwood TS	230/27.6	L24L/L26L
Nelson TS	115/27.6	W5N/W6NL
Strathroy TS	115/27.6	W2S
Talbot TS (T1/T2 and T3/T4)	230/27.6	W36/W37
Tillsonburg TS	115/27.6	W14
Wonderland TS	230/27.6	N21W/N22W
Woodstock TS	115/27.6	K7/K12

Appendix B. Transmission Lines in the London Area Region

Circuit Designations	Location	Voltage (kV)
N21W, N22W	Scott TS to Buchanan TS	230
W42L, W43L	Longwood TS to Buchanan TS	230
W44LC	Longwood TS to Chatham TS to Buchanan TS	230
W45LS	Longwood TS to Spence SS to Buchanan TS	230
W36, W37	Buchanan TS to Talbot TS and Clarke TS	230
D4W, D5W	Buchanan TS to Detweiler TS	230
M31W, M32W, M33W	Buchanan TS to Middleport TS	230
W2S	Buchanan TS to Strathroy TS	115
W5N	Buchanan TS to Nelson TS	115
W6NL	Buchanan TS to Highbury TS to Nelson TS	115
W9L	Buchanan TS to Highbury TS	115
W7, W12	Buchanan TS to CTS	115
WW1C	Buchanan TS to CTS	115
W8T	Buchanan TS to ESWF JCT	115
WT1T	Cranberry Junction to Tillsonburg TS	115
W14	Buchanan TS to Cranberry Junction	115
WT1A	Aylmer TS to Lyons JCT	115
K7, K12	Karn TS to Commerce Way TS	115

Appendix C. Distributors in London Area Region

Distributor Names	Station Name	Connection Type
Entegrus Power Lines Inc. [Middlesex]	Edgeware TS	Tx
	Longwood TS	Dx
	Strathroy TS	Dx
		Tx
ERTH Power Corporation	Aylmer TS	Tx
	Buchanan TS	Dx
	Edgeware TS	Dx
	Ingersoll TS	Dx
	Tillsonburg TS	Dx
Hydro One Networks Inc.	Aylmer TS	Tx
	Buchanan TS	Tx
	Clarke TS	Tx
	Edgeware TS	Tx
	Highbury TS	Tx
	Ingersoll TS	Tx
	Longwood TS	Tx
	Strathroy TS	Tx
	Tillsonburg TS	Tx
	Wonderland TS	Tx
	Woodstock TS	Tx
London Hydro Inc.	Buchanan TS	Dx
		Tx
	Clarke TS	Tx
	Edgeware TS	Dx
	Highbury TS	Dx
		Tx
	Nelson TS	Tx
	Talbot TS	Tx
	Wonderland TS	Dx
		Tx
Tillsonburg Hydro Inc.	Tillsonburg TS	Tx

Appendix D. London Area Region Load Forecast

Table D1: London Area Regional Non-Coincident Net Load Forecast

Transformer Station	LTR* (MW)	Quantities	Reference	Near Term Forecast (MW)					Medium Term Forecast (MW)				
			2021**	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Aylmer TS		Gross	32.46	32.98	33.51	34.05	34.61	35.16	35.73	36.31	36.90	37.49	38.10
		DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		CDM		0.67	1.06	1.38	1.66	1.93	2.22	2.49	2.75	2.99	3.04
	40	Net		32.29	32.44	32.65	32.92	33.22	33.49	33.80	34.13	34.48	35.03
Buchanan TS		Gross	131.49	133.22	134.96	136.73	138.52	140.34	142.17	144.04	145.92	147.84	149.77
		DG		14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74
		CDM		2.70	4.26	5.54	6.65	7.69	8.85	9.86	10.87	11.81	11.96
	173	Net		115.77	115.96	116.45	117.12	117.90	118.58	119.44	120.31	121.29	123.07
Clarke TS		Gross	102.45	103.58	104.72	105.88	107.05	108.23	109.43	110.64	111.86	113.10	114.35
		DG		3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40
		CDM		2.10	3.30	4.29	5.14	5.93	6.81	7.57	8.33	9.03	9.13
	103	Net		98.08	98.03	98.20	98.51	98.91	99.22	99.67	100.13	100.67	101.82
Commerce Way TS		Gross	34.55	35.12	35.69	36.27	36.87	37.47	38.08	38.70	39.33	39.97	40.63
		DG		2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
		CDM		0.71	1.13	1.47	1.77	2.05	2.37	2.65	2.93	3.19	3.25
	106	Net		31.46	31.62	31.86	32.15	32.47	32.77	33.11	33.46	33.84	34.44
Edgeware TS		Gross	102.45	103.93	105.43	121.83	126.36	127.92	129.52	131.13	132.77	134.43	136.12
		DG		4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.44
		CDM		2.11	3.33	4.93	6.07	7.01	8.06	8.98	9.89	10.74	10.87
	180	Net		97.35	97.64	112.43	115.81	116.44	116.98	117.68	118.40	119.22	120.81
Highbury TS		Gross	74.76	75.72	76.70	77.69	78.69	79.70	80.72	81.76	82.81	83.88	84.96
		DG		5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
		CDM		1.53	2.42	3.15	3.78	4.37	5.02	5.60	6.17	6.70	6.79
	80	Net		68.68	68.77	69.02	69.39	69.82	70.18	70.65	71.13	71.66	72.67
Ingersoll TS		Gross	69.40	71.92	74.53	77.24	80.05	82.96	85.98	89.10	92.34	95.70	99.17
		DG		12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.93
		CDM		1.46	2.35	3.13	3.85	4.55	5.35	6.10	6.88	7.64	7.92
	158	Net		57.51	59.24	61.17	63.26	65.47	67.68	70.05	72.51	75.11	78.33
Longwood TS		Gross	40.27	41.14	42.04	42.95	43.88	44.83	45.80	46.80	47.81	48.85	49.91
		DG		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.12
		CDM		0.83	1.33	1.74	2.11	2.46	2.85	3.20	3.56	3.90	3.99
	121	Net		39.15	39.55	40.05	40.61	41.21	41.79	42.43	43.09	43.79	44.80
Nelson TS		Gross	53.39	53.78	54.17	54.56	54.95	55.34	55.74	56.14	56.55	56.96	57.37
		DG		17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55
		CDM		1.09	1.71	2.21	2.64	3.03	3.47	3.84	4.21	4.55	4.58
	107	Net		35.14	34.91	34.80	34.76	34.77	34.73	34.75	34.79	34.86	35.24
Strathroy TS		Gross	39.63	40.19	40.77	41.35	41.94	42.54	43.15	43.77	44.39	45.03	45.67
		DG		8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
		CDM		0.81	1.29	1.67	2.01	2.33	2.69	3.00	3.31	3.60	3.65
	56	Net		30.75	30.86	31.05	31.30	31.58	31.84	32.14	32.46	32.80	33.40
Talbot T1/T2		Gross	121.81	122.79	123.77	124.77	125.78	126.79	127.81	128.84	129.87	130.92	131.97
		DG		-	-	-	-	-	-	-	-	-	-
		CDM		2.49	3.90	5.05	6.04	6.95	7.95	8.82	9.68	10.46	10.54
	113	Net		120.30	119.87	119.72	119.73	119.84	119.85	120.02	120.20	120.46	121.43
Talbot T3/T4		Gross	172.17	173.87	175.59	177.33	179.08	180.85	182.64	184.45	186.27	188.11	189.97
		DG		12.28	12.28	12.28	12.28	12.28	12.28	12.28	0.52	0.52	0.45
		CDM		3.52	5.54	7.18	8.60	9.91	11.37	12.63	13.88	15.03	15.18
	161	Net		158.06	157.77	157.86	158.20	158.66	158.99	159.54	171.87	172.56	174.35
Tillsonburg TS		Gross	94.95	96.18	97.42	98.68	99.95	101.25	102.56	103.88	105.23	106.59	107.96
		DG		3.54	3.54	3.54	3.54	3.54	3.54	0.97	0.97	0.97	0.91
		CDM		1.95	3.07	4.00	4.80	5.55	6.38	7.11	7.84	8.51	8.62
	103	Net		90.68	90.80	91.14	91.61	92.16	92.63	95.80	96.42	97.10	98.43
Wonderland TS		Gross	91.36	92.76	94.17	95.61	97.08	98.56	100.07	101.60	103.15	104.73	106.33
		DG		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.87
		CDM		1.88	2.97	3.87	4.66	5.40	6.23	6.95	7.68	8.37	8.49
	115	Net		88.87	89.20	89.74	90.41	91.16	91.84	92.64	93.47	94.36	95.96
Woodstock TS		Gross	64.10	64.68	65.27	65.87	66.47	67.07	67.69	68.30	68.92	69.55	70.19
		DG		2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.23	1.60
		CDM		1.31	2.06	2.67	3.19	3.68	4.21	4.68	5.13	5.56	5.61
	81	Net		61.08	60.92	60.91	60.99	61.11	61.18	61.34	61.50	61.77	62.98
Industrial Customer #1			12	12	12	12	12	12	12	12	12	12	12
Industrial Customer #2			19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Industrial Customer #3			2	2	2	2	2	2	2	2	2	2	2
London Area Total				1159	1161	1181	1191	1199	1206	1217	1238	1248	1267

*Station LTR is based on 90% power factor

** Adjusted to extreme weather

Note (1) Edgeware TS step increases in 2024 & 2025 reflects a new connection request of 20MW.

TABLE D2: LONDON AREA REGIONAL COINCIDENT NET LOAD FORECAST

Transformer Station	Quantities	Reference	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2021^	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Aylmer TS	Gross	25.99	26.41	26.83	27.27	27.71	28.16	28.61	29.07	29.54	30.02	30.51
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	CDM		0.54	0.85	1.10	1.33	1.54	1.78	1.99	2.20	2.40	2.44
	Net		25.85	25.97	26.14	26.36	26.59	26.81	27.06	27.32	27.60	28.05
Buchanan TS	Gross	129.03	130.72	132.43	134.17	135.92	137.70	139.51	141.34	143.19	145.06	146.96
	DG		14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74	14.74
	CDM		2.65	4.18	5.43	6.53	7.55	8.68	9.68	10.67	11.59	11.74
	Net		113.33	113.51	113.99	114.65	115.42	116.08	116.92	117.78	118.73	120.48
Clarke TS	Gross	86.32	87.27	88.24	89.21	90.20	91.20	92.20	93.22	94.25	95.29	96.35
	DG		3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40
	CDM		1.77	2.78	3.61	4.33	5.00	5.74	6.38	7.02	7.61	7.70
	Net		82.11	82.06	82.21	82.47	82.80	83.07	83.45	83.84	84.29	85.26
Commerce Way TS	Gross	32.18	32.71	33.24	33.78	34.34	34.90	35.47	36.05	36.63	37.23	37.84
	DG		2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
	CDM		0.66	1.05	1.37	1.65	1.91	2.21	2.47	2.73	2.97	3.02
	Net		29.10	29.25	29.47	29.74	30.04	30.32	30.64	30.96	31.32	31.87
Edgeware TS	Gross	102.45	103.93	105.43	121.83	126.36	127.92	129.52	131.13	132.77	134.43	136.12
	DG		4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.44
	CDM		2.11	3.33	4.93	6.07	7.01	8.06	8.98	9.89	10.74	10.87
	Net		97.35	97.64	112.43	115.81	116.44	116.98	117.68	118.40	119.22	120.81
Highbury TS	Gross	74.61	75.57	76.54	77.53	78.52	79.53	80.56	81.59	82.64	83.71	84.78
	DG		5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
	CDM		1.53	2.41	3.14	3.77	4.36	5.01	5.59	6.16	6.69	6.77
	Net		68.52	68.61	68.87	69.24	69.66	70.03	70.49	70.97	71.50	72.50
Ingersoll TS	Gross	54.92	56.92	58.99	61.13	63.35	65.65	68.04	70.51	73.08	75.73	78.49
	DG		12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.95	12.93
	CDM		1.15	1.86	2.48	3.04	3.60	4.23	4.83	5.44	6.05	6.27
	Net		42.82	44.18	45.71	47.36	49.11	50.86	52.74	54.69	56.74	59.29
Longwood TS	Gross	37.74	38.56	39.39	40.25	41.12	42.01	42.93	43.86	44.81	45.78	46.77
	DG		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.12
	CDM		0.78	1.24	1.63	1.98	2.30	2.67	3.00	3.34	3.66	3.74
	Net		36.62	36.99	37.46	37.99	38.55	39.09	39.69	40.31	40.96	41.92
Nelson TS	Gross	37.94	38.22	38.49	38.77	39.05	39.33	39.61	39.90	40.19	40.48	40.77
	DG		17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55	17.55
	CDM		0.77	1.21	1.57	1.88	2.16	2.47	2.73	2.99	3.23	3.26
	Net		19.90	19.73	19.65	19.63	19.63	19.60	19.62	19.65	19.70	19.96
Strathroy TS	Gross	30.42	30.86	31.30	31.74	32.20	32.66	33.13	33.60	34.08	34.57	35.06
	DG		8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
	CDM		0.63	0.99	1.29	1.55	1.79	2.06	2.30	2.54	2.76	2.80
	Net		21.60	21.68	21.83	22.02	22.24	22.44	22.67	22.91	23.18	23.63
Talbot T1/T2	Gross	109.09	109.96	110.85	111.74	112.64	113.55	114.46	115.38	116.31	117.25	118.19
	DG		-	-	-	-	-	-	-	-	-	-
	CDM		2.23	3.50	4.53	5.41	6.22	7.12	7.90	8.67	9.37	9.44
	Net		107.74	107.35	107.22	107.23	107.33	107.34	107.49	107.65	107.88	108.75
Talbot T3/T4	Gross	152.03	153.53	155.05	156.58	158.13	159.69	161.27	162.87	164.48	166.10	167.75
	DG		12.28	12.28	12.28	12.28	12.28	12.28	12.28	0.52	0.52	0.45
	CDM		3.11	4.89	6.34	7.60	8.75	10.04	11.15	12.25	13.27	13.40
	Net		138.13	137.87	137.96	138.25	138.66	138.95	139.43	151.70	152.31	153.89
Tillsonburg TS	Gross	94.21	95.43	96.66	97.91	99.18	100.46	101.76	103.07	104.41	105.76	107.12
	DG		3.54	3.54	3.54	3.54	3.54	3.54	0.97	0.97	0.97	0.91
	CDM		1.93	3.05	3.97	4.76	5.50	6.33	7.06	7.78	8.45	8.56
	Net		89.95	90.07	90.40	90.87	91.41	91.88	95.05	95.66	96.34	97.66
Wonderland TS	Gross	87.66	89.00	90.36	91.74	93.14	94.57	96.01	97.48	98.97	100.49	102.02
	DG		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.87
	CDM		1.80	2.85	3.72	4.47	5.18	5.98	6.67	7.37	8.03	8.15
	Net		85.19	85.51	86.02	86.67	87.38	88.04	88.81	89.60	90.46	92.00
Woodstock TS	Gross	64.10	64.68	65.27	65.87	66.47	67.07	67.69	68.30	68.92	69.55	70.19
	DG		2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.23	1.60
	CDM		1.31	2.06	2.67	3.19	3.68	4.21	4.68	5.13	5.56	5.61
	Net		61.08	60.92	60.91	60.99	61.11	61.18	61.34	61.50	61.77	62.98
Industrial Customer #1		12	12	12	12	12	12	12	12	12	12	12
Industrial Customer #2		19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Industrial Customer #3		2	2	2	2	2	2	2	2	2	2	2
London Area Total			1053	1055	1074	1083	1090	1097	1107	1127	1136	1153

^ Adjusted to extreme weather
Note (1) Edgeware TS step increases in 2024 & 2025 reflects a new connection request of 20MW.

TABLE D3: CONSERVATION AND DEMAND FORECAST (SOURCE: IESO)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2.0%	3.2%	4.1%	4.8%	5.5%	6.2%	6.8%	7.4%	8.0%	8.0%

Appendix F. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code

APPENDIX C. Regional Planning: RIP Report 2022 Greater Bruce/Huron Region

Greater Bruce - Huron

Regional Infrastructure Plan

April 25, 2022

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Power Lines Inc.
ERTH Power Corporation
Festival Hydro Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

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Disclaimer

This Regional Infrastructure Plan (“RIP”) report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs (2019-2028) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the RIP report (“the Other Third Parties”), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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Executive Summary

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER BRUCE-HURON (GBH) REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Entegrus Power Lines Inc.
- ERTH Power Corporation
- Festival Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Wellington North Power Inc.
- Westario Power Inc.

In the first cycle of the Regional Planning (RP) process for the GBH Region, a Needs Assessment ("NA") was published in May 2016 and recommended that an Integrated Regional Resource Plan ("IRRP") was not required. The first cycle of RP process was completed in August 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This RIP is the final phase of the second cycle of the regional planning process for the Greater Bruce-Huron Region, which follows the completion of the South Huron-Perth Sub-Region IRRP in September 2021 and the GBH Needs Assessment in May 2019. This report provides a consolidated summary of needs and recommended plans for the Greater Bruce-Huron Region for the near-term (up to 5 years) and mid-term (5 to 10 years). Long term needs (10 to 20 years) in the region, include circuit L7S capacity (which has transitioned to the mid-term with recent new connection requests) and Hanover TS capacity. The delivery point performance along circuit L7S continues to be monitored to confirm whether recent upgrades have resulted in improvements, and to determine if additional plans are required.

Investments planned for the Greater Bruce-Huron Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Increase Capacity of Limiting Section of L7S	2023-2025	$550k - TBD
2	Continued assessment of L7S condition to address deteriorating components	TBD	TBD

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GREATER BRUCE-HURON REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the joint study carried out by Hydro One, Entegrus Power Lines Inc., ERTH Power Corporation, Festival Hydro Inc., Hydro One Distribution, the Independent Electricity System Operator (“IESO”), Wellington North Power Inc. and Westario Power Inc. in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

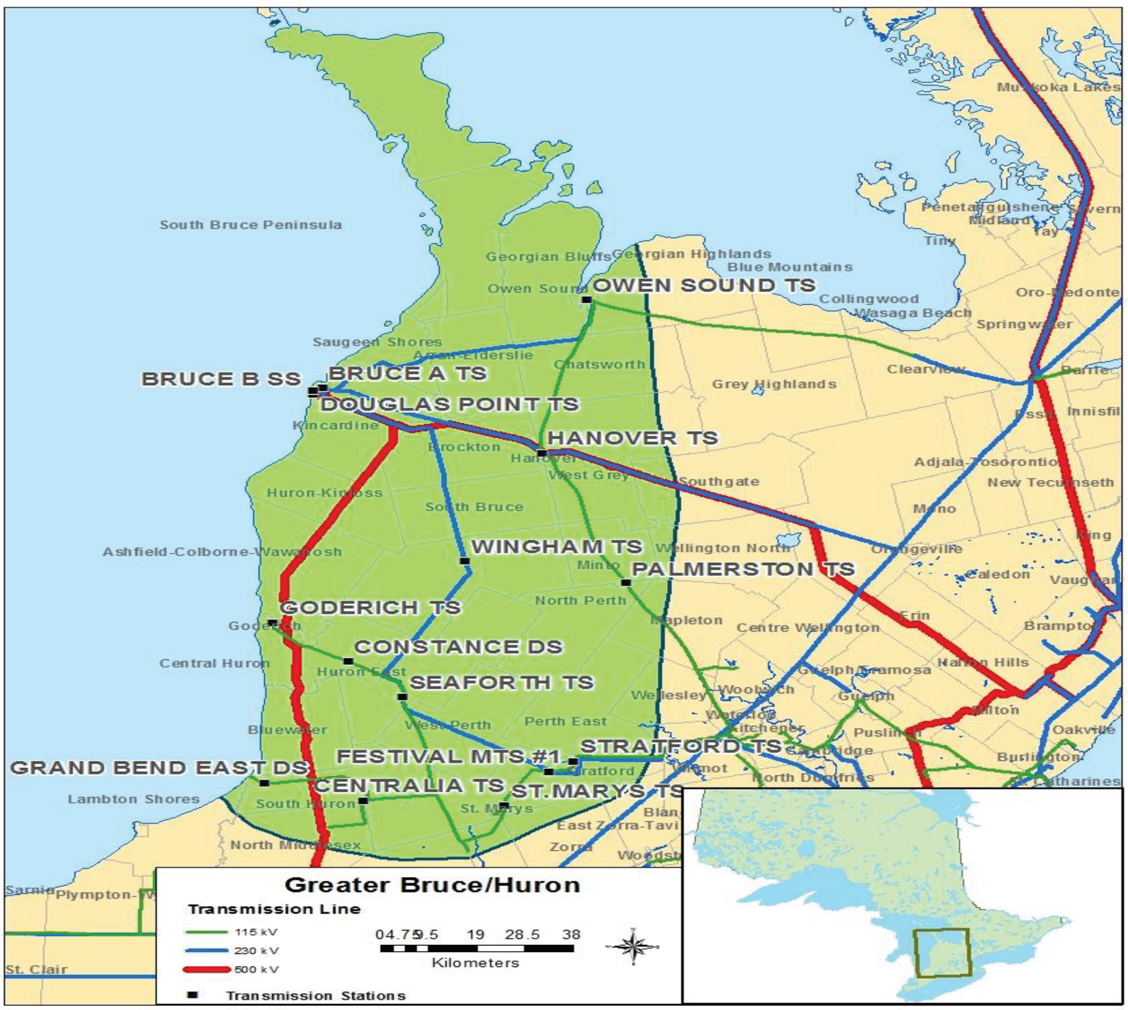

Figure 1-1. Greater Bruce Huron Region

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. Electrical supply to the Region is provided from six 230 kV and twelve 115 kV step-down transformer stations. The boundaries of the Region are highlighted in Figure 1-1 above.

1.1 Objective and Scope

This RIP report examines the needs in the Greater Bruce-Huron Region. Its objectives are:

- To develop a wires plan to address needs identified in previous planning phases for which a wires only alternative was recommended by the Working Group
- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region

The RIP reviewed factors such as the load forecast, major high voltage sustainment work, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (CDM), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2019-2028) identified in previous planning phases (Needs Assessment or Local Plan)
- Identification of any new needs over the 2019-2028 period
- Develop a plan to address any longer term needs identified by the Working Group

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code (“TSC”) and the Distribution System Code (“DSC”). The process consists of four phases: the Needs Assessment (“NA”), the Scoping Assessment (‘SA”), the Integrated Regional Resource Plan (“IRRP”), and the Regional Infrastructure Plan (“RIP”).

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company (“LDC”) or customer and develops a Local Plan (“LP”) to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource options (e.g. CDM, generation and Distributed Energy Resources (“DER”)) at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution was determined to be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the Greater Bruce-Huron region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, IRRP, and LP phases of regional planning.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

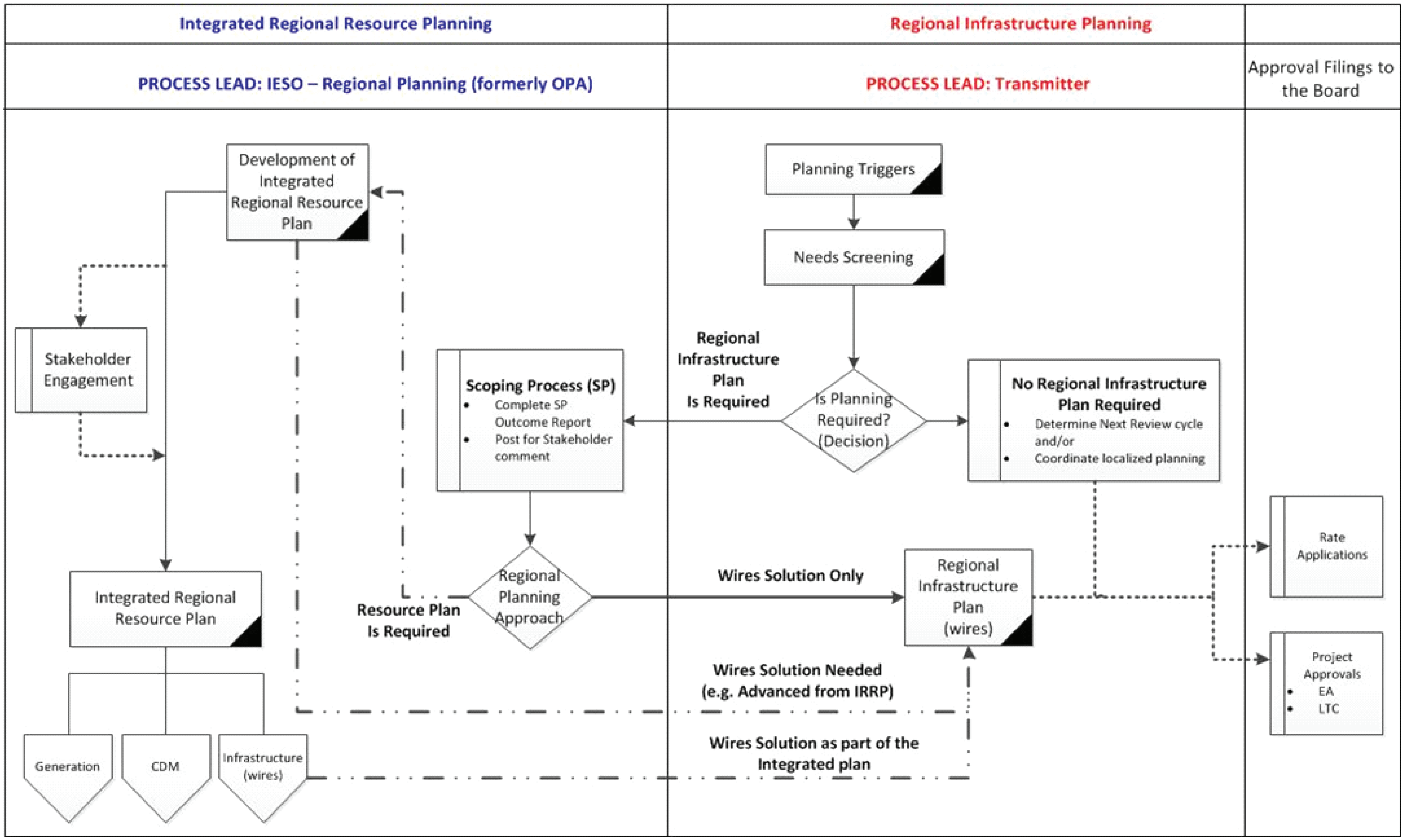

Figure 2-1. Regional Planning Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
    - Gross and net peak demand forecast at the transformer station level. This includes the effect of any distributed generation and/or conservation and demand management programs.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

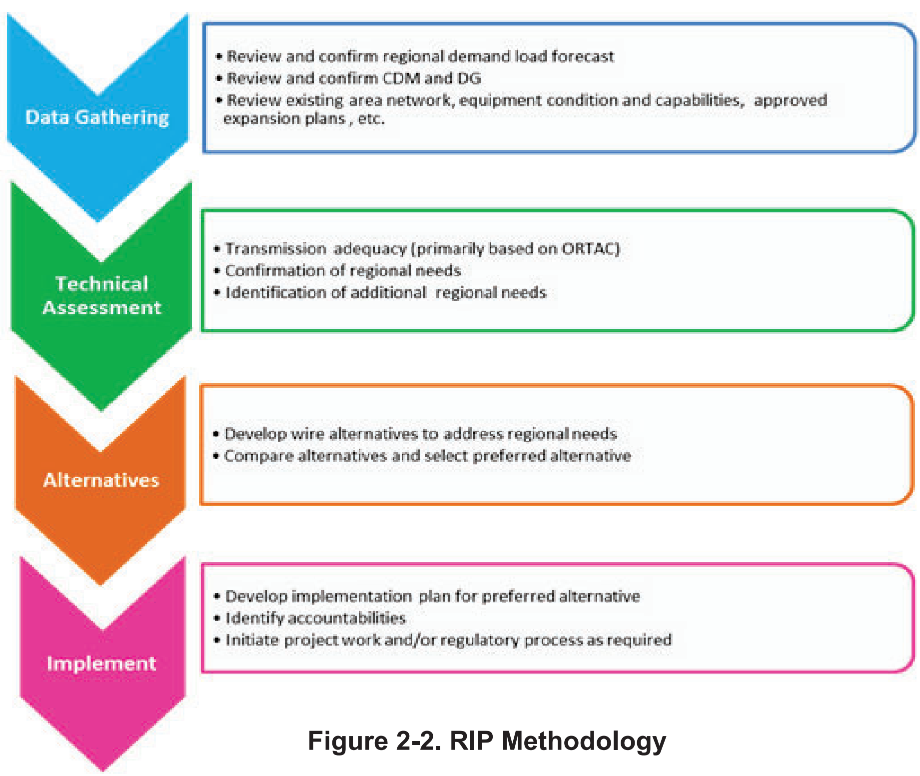

Figure 2-2. RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER BRUCE-HURON REGION COMPRISES OF THE COUNTIES OF BRUCE, HURON, AND PERTH, AS WELL AS PORTIONS OF GREY, WELLINGTON, WATERLOO, OXFORD, AND MIDDLESEX COUNTIES AS SHOWN IN FIGURE 3-1.

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the Region. The majority of the electrical supply in the region is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Within the Region, electricity is delivered to the end users of LDCs and directly-connected industrial customers by eleven Hydro One step-down transformation stations, as well as seven customer-owned transformer or distribution stations supplied directly from the transmission system. Appendix A lists all step-down transformer stations in the Region. Appendix B lists all transmission circuits and Appendix C lists LDCs in the Region. The Single Line Diagram for the Greater Bruce-Huron Region transmission system facilities is shown below in Figure 3-2.

Figure 3-1. Geographical Area of the Greater Bruce-Huron Region with Electrical Layout

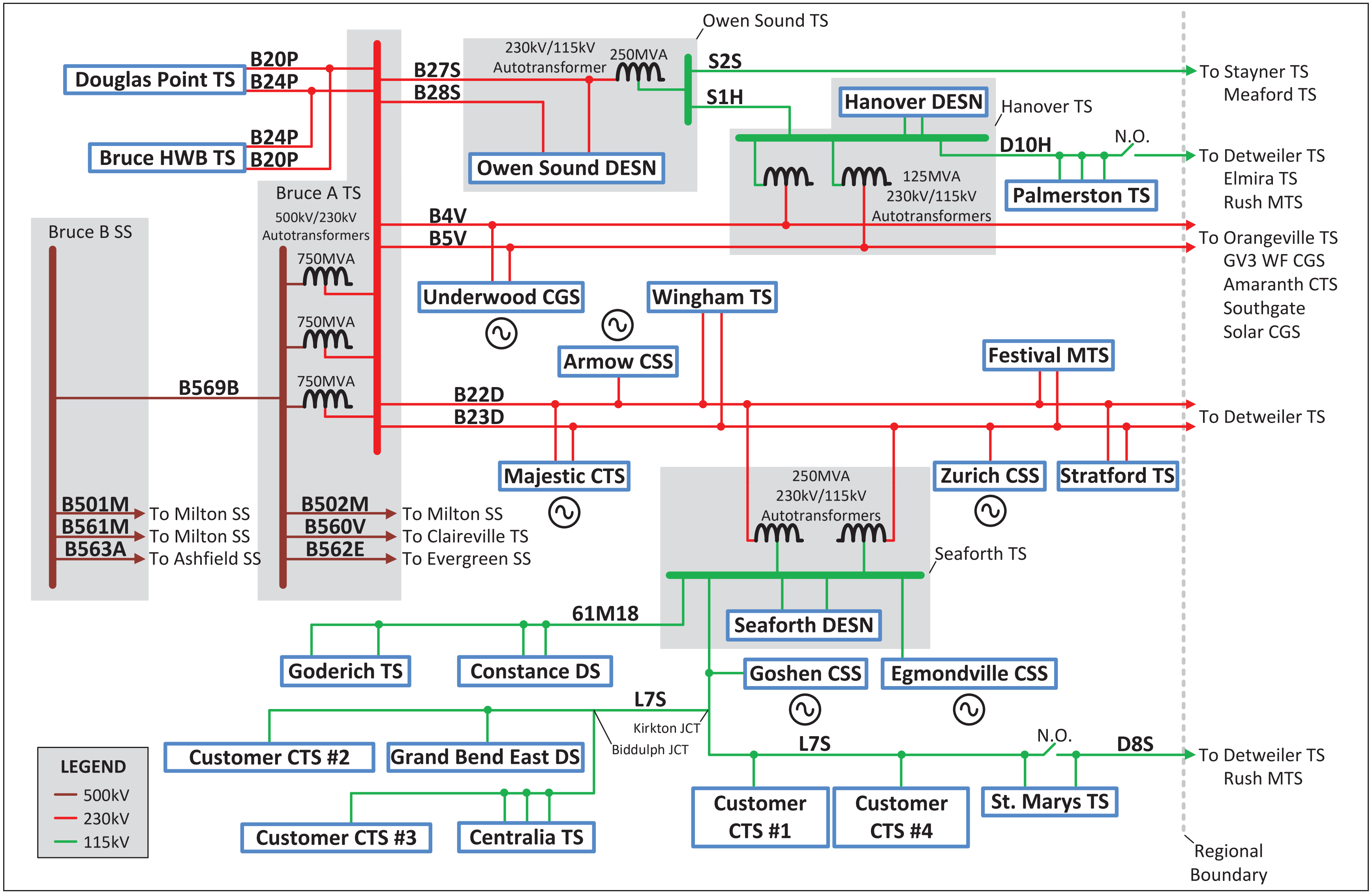

Figure 3-2. Greater Bruce-Huron Region Single-Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GREATER BRUCE-HURON REGION.

In addition to Hydro One's ongoing transmission station and line sustainment programs, specific projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For bulk power system transfer needs:

- 500 kV double circuit line from the Bruce Nuclear Complex to Milton SS in 2011
- 230 kV Static Var Compensator (SVC) at Detweiler TS in 2011
- Bruce Reactor Switching Scheme (RSS) modifications in 2018

For major station refurbishment needs based on asset condition assessment:

- Goderich TS in 2017
- Centralia TS in 2018
- Palmerston TS in 2019
- Stratford TS in 2021

For renewable generation connection needs:

- 230 kV Dufferin Wind Farm into Orangeville TS in 2014
- 500 kV Jericho/Adelaide/Bornish Wind Farms into Evergreen SS in 2014
- 230 kV Grand Valley 3 Wind Farm onto circuit B4V in 2015
- 115 kV Bluewater Wind Farm into Seaforth TS in 2015
- 115 kV Goshen Wind Farm onto circuit L7S in 2015
- 500 kV K2 Wind Farm into Ashfield SS in 2015
- 230 kV Grand Bend Wind Farm onto circuit B23D in 2016
- 230 kV Armow Wind Farm onto circuit B22D in 2016
- 230 kV Southgate Solar Farm onto circuit B4V in 2016

The following projects are underway:

- Bruce A TS 230 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q2 2022.
- Wingham TS switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q2 2023
- Seaforth TS switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q4 2024
- Bruce B SS 500 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q4 2024.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Bruce-Huron Region is forecast to increase annually between 2019 and 2028. The growth rate varies across the Region with most of the growth concentrated in the County of Bruce and more specifically in the Kincardine area. The Region's 2022 RIP load forecasts are provided in Appendix D and were prepared by the Working Group upon initiation of the RIP phase. The RIP forecasts are identical to the Needs Assessment forecast except as otherwise noted in Appendix D.

As per the load forecasts in Appendix D, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.7% annually from 2019-2028 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 2.3% from 2019-2028.

As per the load forecasts in Appendix D, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 1.2% annually from 2019-2028 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 1.9% from 2019-2028.

Figure 5-1 shows the Region's gross and net *winter* coincident forecasts while Figure 5.2 shows the Region's gross and net *summer* coincident forecasts. The regional-coincident (at the same time) forecast represents the total peak load of all 18 step-down transformer stations in the Region.

Based on historical load and on the coincident load forecasts, the Region's winter coincident peak load is larger than its summer coincident peak load. Based on historical load and the non-coincident load forecasts, the Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors, assessment for this Region was conducted for both summer and winter peak load.

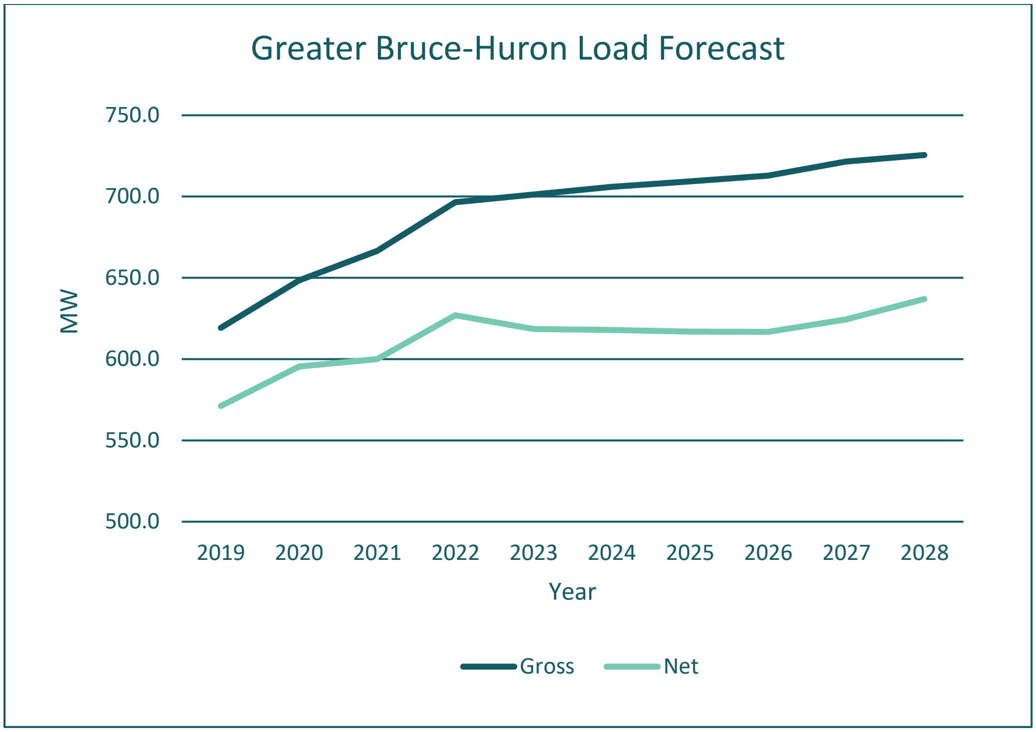

Figure 5-1. Greater Bruce-Huron Region Winter Coincident Forecast

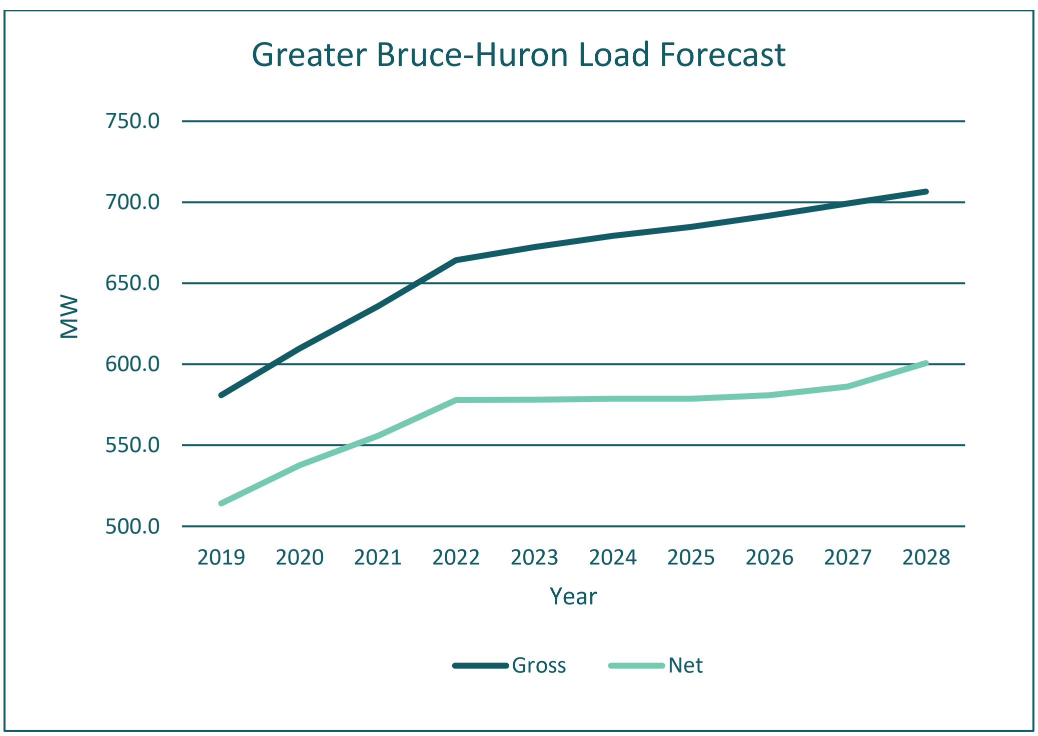

Figure 5-2. Greater Bruce-Huron Region Summer Coincident Forecast

5.2 Study Assumptions

The following assumptions are made in this report.

1) The study period for the RIP assessments is 2019-2028.

2) All planned facilities listed in Section 4 are assumed to be in-service.

3) The Region contains some stations that are summer peaking and others that are winter peaking. The assessment is therefore based on both summer and winter peak loads.

4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer and winter 10-Day Limited Time Rating (LTR), as appropriate.

5) Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2019-2028 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STEP-DOWN TRANFORMATION STATION FACILITIES SUPPLYING THE GREATER BRUCE-HURON REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle, three regional assessments have been conducted for the Greater Bruce-Huron Region. The findings of these studies are input to the RIP. The studies are:

1) Needs Assessment Report - Greater Bruce-Huron Region, May 2019
2) Greater Bruce-Huron Region Scoping Assessment Report, September 2019
3) Southern Huron-Perth Sub-Region IRRP, September 2021

This RIP reviewed the loading on transmission lines and stations in the Greater Bruce-Huron Region based on the RIP load forecast. Sections 6.1-6.6 presents the results of this review and Table 6-1 lists the Region’s needs identified in both the Needs Assessment and the RIP phases.

In addition, this RIP reviewed an updated list of Hydro One transmission lines and station major sustainment work over the next several years to determine if there are opportunities to consolidate with any emerging development needs within the Region. Section 7.5 presents the results of this review.

Table 6-1: Near and Mid-term Regional Needs

Type	Section	Needs	Timing
Needs and Timing Identified in the Needs Assessment Report [1]			
Transmission Circuit Capacity	7.2	Overload on sections of 115 kV single circuit line, L7S	2022 (emergency rating exceeded based on NA summer gross coincident load forecast)
			2027 (continuous rating exceeded based on NA summer gross load forecast)
End-Of-Life Equipment Needs	7.4	Wingham TS	2022
		Stratford TS	2021
		Seaforth TS	2023
		Hanover TS (T2)	2023

6.1 230 kV Transmission Facilities

Half of the 230 kV transmission circuits in the Greater Bruce-Huron Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of Ontario’s transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the KWCG, Georgian Bay and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Bruce A TS to Orangeville TS 230kV transmission circuits B4V/B5V – supplies Hanover TS
2) Bruce A TS to Detweiler TS 230kV transmission circuits B22D/ B23D – supplies Wingham TS, Seaforth TS, Festival MTS #1, and Stratford TS
3) Bruce A TS to Owen Sound TS 230kV transmission circuits B27S/B28S – supplies Owen Sound TS
4) Bruce A TS to Douglas Point TS 230kV transmission circuits B20P/B24P – supplies Douglas Point TS and Bruce HWP B TS

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the Greater Bruce-Huron Region is provided by Hydro One’s 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Three (3) 500/230kV autotransformers at Bruce A TS
2) Two (2) 230/115kV autotransformers at Seaforth TS
3) Two (2) 230/115kV autotransformers at Hanover TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period.

6.3 Supply Capacity of the 115 kV Network

The Greater Bruce-Huron Region contains four (4) single circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Hanover TS to Detweiler TS 115 kV transmission circuit D10H with Normally Open (N/O) point at Palmerston TS – supplies Palmerston TS & Elmira TS
2) Seaforth TS to Goderich TS 115 kV transmission circuit 61M18 – supplies Constance DS and Goderich TS
3) Seaforth TS to St. Marys TS 115 kV transmission circuit L7S – supplies Grand bend East DS, Lake Huron WTP CTS, Centralia TS, McGillivray R&BP CTS, Enbridge Bryanston CTS and St. Marys Cement CTS
4) Hanover TS to Owen Sound TS 115 kV transmission circuit S1H

The RIP review shows that based on current forecast station loadings, the supply capacity of the 115 kV network is adequate over the study period. The Needs Assessment coincident forecast identified that circuit L7S will exceed its short- and long-term emergency rating in 2022 and its continuous rating in 2027, however, the updated IRRP forecast resulted in these needs being deferred to the long-term period (2029-2038).

6.4 Step-down Transformer Stations

There are 18 step-down transformer stations within the Greater Bruce-Huron Region. Fourteen supply electricity to LDCs and four are transmission-connected industrial customer stations. These stations are listed in Appendix C. Of the 18 stations, 3 of them are owned and operated by LDCs.

As part of the Needs Assessment, IRRP, as well as this RIP, step-down transformation station capacity was reviewed. Since the May 2019 Needs Assessment, the load forecasts at stations supplied by L7S were updated during the IRRP phase of Regional Planning, while the other station forecasts remained unchanged; refer to Appendix D for the updated forecasts. The analysis showed that the gross load forecasts at all stations can be accommodated over the study period.

6.5 Other Items Identified During Regional Planning

6.5.1 End-Of-Life Equipment Replacement Needs

Wingham TS – T1/T2 and Component Replacement

Wingham TS is a load supply station built in 1965. The station has two 50/67/83 MVA step-down transformers connected to the 230 kV circuits B22D and B23D (Bruce x Detweiler) and supplies Hydro One Distribution via four 44 kV feeders.

The current scope of this project is to replace the 230/44 kV step-down transformers, T1 and T2 and associated surge arrestors.

Based on the load forecast, similar equipment ratings are required for the EOL replacement. This project is underway and the planned in-service date for the project is in year 2023.

Stratford TS – T1 and Component Replacement

Stratford TS is a load supply station built in 1950. The station has two 50/67/83 MVA step-down transformers connected to 230 kV circuits B22D and B23D (Bruce x Detweiler) and supplies Festival Hydro Inc., Hydro One Distribution as well as other embedded LDCs, via eight 27.6 kV feeders. Transformers T1 and T2 are in service since 1970 and 1997 respectively.

The current scope of this project included the replacement of 230/27.6 kV transformer T1 and associated equipment.

Based on the load forecast similar equipment ratings are required for EOL replacement. The planned in-service date for the project was set for 2023, however the project work was advanced and completed in 2021.

Seaforth TS – T5/T6/T1/T2 and Component Replacement

Seaforth TS is a major station and consists of two 230/115 kV, 150/200/250 MVA autotransformers supplied by 230 kV circuits B22D and B23D (Bruce x Detweiler). The 115 kV yard from Seaforth TS supplies nearly 200 km of single circuit supply along the circuits L7S and 61M18. Seaforth TS also consists of two 115/27.6 kV, 25/33/42 MVA step-down transformers and supplies Hydro One Distribution and embedded LDCs via four 27.6 kV feeders.

The current scope of this project is to replace 230/115 kV autotransformers T5, T6, step-down transformers T1, T2, the capacitor breaker SC1B and several high voltage and low voltage switches that are at end of their life. Operations has identified the need for refined voltage control on the 115 kV system. Therefore, the new autotransformers at Seaforth TS will be equipped with Under Load Tap Changers (ULTCs).

Based on the load forecast for the station similar equipment ratings are required for EOL replacement of all equipment discussed above. The planned in-service date for the project is in year 2024.

Hanover TS – T2 and Component Replacement

Hanover TS consists of two 230/115 kV, 75/100/125 MVA autotransformers supplied by 230 kV circuits B4V and B5V (Bruce x Orangeville). The 115 kV yard has connectivity to Detweiler TS via 115 kV transmission circuit D10H with a Normally Open point at Palmerston TS. Another 115 kV transmission circuit S1H connects to Owen Sound TS. Hanover TS also consists of two 115/44 kV, 50/67/83 MVA step-down transformers connecting to six feeders and one capacitor bank, supplying Hydro One Distribution and embedded LDCs.

The scope of this project included the replacement of 230 kV motorized switches, 115/44 kV step-down transformer T2 and associated equipment, 115 kV motorized switches, surge arrestors, auto-ground switches and potential transformers. This work was planned to be completed in 2028, however due to a recent transformer tap changer failure, T2 and its associated transformer switch are being replaced immediately and are expected in-service by the end of 2022. The remaining component replacements that were planned as part of the T2 work will be bundled with the replacement of T1 and have an expected in-service date of 2031.

6.6 Long-Term Regional Needs

115kV L7S Circuit

In analyzing the updated IRRP coincident load forecast for stations supplied by L7S, no capacity needs were identified during the study period (2019-2028), however long-term capacity needs were observed under the high growth scenario following a single element contingency. Following the loss of D8S, a long-term capacity need was identified to emerge in 2035. Furthermore, with a planned outage to D8S, a capacity need begins to emerge in 2030, following the loss of Seaforth T6. With the uncertainty of how the forecast will develop over the next 5-10 years the working group will continue to monitor load growth to determine when an L7S upgrade is required. In the meantime, CDM programs and load transfers can be implemented to mitigate overloading the L7S circuit.

Recently, there have been connection requests at Grand Bend East DS which will result in increased loading on L7S, bringing the demand on the circuit closer to its Load Meeting Capability (LMC). The L7S capacity is limited by sub-standard clearance on certain spans of the section of circuit between Seaforth TS and Kirkton JCT, and this has triggered a re-assessment of this section to address these clearance constraints that are limiting the circuit's capacity.

Hanover TS

In the long-term (2029-2038), Hanover TS is expected to exceed its gross summer load forecast in 2034, however accounting for DER and CDM, the need for additional capacity at the station is deferred to 2038. The end-of-life replacements planned for 2031 will likely increase the station's 10-day LTR by 5-10 MW, further deferring the need. Since the capacity need at Hanover TS does not arise for another 12-16 years, it is recommended to monitor load growth and re-evaluate the need in the next regional planning cycle.

7. REGIONAL PLANS

THIS SECTION SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS LISTED IN TABLE 6-1.

7.1 Transmission Circuit Capacity

7.1.1 Circuit L7S

L7S is a single 115 kV circuit transmission line operated radial from Seaforth TS to St. Marys TS. As per the updated IRRP coincident load forecast for stations supplied by L7S, no capacity needs were identified during the study period, however, the recent connection requests at Grand Bend East DS have triggered a re-assessment of the L7S section between Seaforth TS and Kirkton JCT to address the sub-standard clearances that are limiting the circuit's capacity.

Recommended Plan and Current Status

To address the potential need for additional capacity on L7S, it is recommended that Hydro One Transmission proceed with the re-assessment of the limiting section of L7S, currently underway, to increase the limiting spans' sag temperature from 83°C to 125°C. Addressing these sub-standard clearances will result in an L7S capacity increase of more than 10 MW. The Development Plan was initially detailed in the 2016 Local Planning – L7S Thermal Overload [3]. The Development Plan specified that when loading on L7S is expected to exceed its limits within a 3 year period, Hydro One Transmission will increase the thermal rating of the limiting spans of circuit L7S. The cost to increase the rating was estimated to be approximately $550k. An updated estimate will be available once the scope is confirmed, following the completion of the re-assessment. Strengthening L7S will be sufficient for supplying load connected to L7S load for the study period and into the long-term. Loading beyond the study period's forecast may then require additional voltage support and Hydro One Transmission will continue to monitor this need. Capacity cost allocation will be as per the Transmission System Code.

7.2 Customer Delivery Point Performance

7.2.1 Customers Supplied from Circuit L7S

The performance of delivery points supplied from circuit L7S, specifically Centralia TS, Grand Bend East DS, St. Marys TS and the 4 industrial customer connections, were reviewed. Specifically, the Centralia TS and McGillivray CTS delivery points, which are supplied by the same branch on L7S, were classified as outliers due to interruptions to this section of the circuit.

While the performance of the McGillivray CTS delivery point, with respect to frequency of outages, has been fluctuating between 1 and 8 interruptions per year since 2015, its performance with respect to duration of outages has drastically improved.

On the other hand, the Centralia TS delivery points were showing exemplary performance with respect to frequency and duration of outages until they were recently classified as outliers with respect to frequency and duration, due to a number of weather and equipment related outages experienced on the L7S circuit in 2019 and 2020.

Current Status and Recommended Plan

In 2021, remotely-operated switches were installed at three locations on the L7S circuit, namely, at Kirkton JCT, Biddulph JCT, and St. Marys TS. These switches will reduce the outage duration and improve restoration by quickly isolating the problematic sections while resupplying the healthy sections of the line. Hydro One's line sustainment and wood pole replacement programs will continue to assess the condition of this circuit to determine where deteriorating components exist and refurbish the sections of concern to improve the integrity of the circuit. Hydro One will continue to monitor the delivery point performance to determine whether further improvement are required. Capital contribution from customers is not anticipated at this time. If, however, capital contribution is required from customers such financial obligation will be determined using methodology set out in the Transmission System Code.

7.2.2 Customers Supplied from Hanover TS

The performance of the Hanover TS delivery points supplied from circuits D10H and S1H, were reviewed. The delivery point performance at Hanover TS with respect to frequency has been excellent over the last 10 years, averaging less than 1 interruption per year. Other than 2019, its performance with respect to duration has also been very good. The delivery points at Hanover TS had not been classified as outliers until 2020 due to a human triggered P&C failure which resulted in a 3-4 hour interruption.

Hanover TS is typically a very reliable station as it is supplied by two 230kV lines and two 115kV lines and the unique event that cause the delivery points to become outliers is very unlikely to reoccur.

Current Status and Recommended Plan

The on-demand replacement of the Hanover T2 transformer and its associated disconnect switch is expected to be completed in 2022, and Hanover T1 transformer and component replacement is planned to be completed in 2031. It is recommended to proceed with the capital plans and continue to monitor the delivery points which are expected to perform reliably.

7.3 Transmission Sustainment Plans

As part of Hydro One's transmitter requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Table 7.1 lists Hydro One's major transmission sustainment *projects* in the Region that are currently planned or underway. There is currently no major line sustainment *projects* planned within the next 5 years. Maintenance *programs* such as insulator, shield wire, structure replacements will continue to be carried out in the Region as required based on equipment/asset condition assessments.

Table 7-1: Hydro One Transmission Major Sustainment Initiatives[1]

Station	General Description of Work	Planning In Service Date
Bruce A TS	• Replacement of 230 kV circuit breakers and switches • Uprating of station strain buses • Replacement of Protection and Control relay building	2022
	• Replacement of 500 kV circuit breakers and switches • Replacement of 2 autotransformers 500/230 kV • Upgrading of Protection and Control equipment	2027
Bruce B SS	• Replacement of 500 kV circuit breakers and switches	2024
Bruce HWP B TS	• Replacement of T7/T8 transformers and associated switches • Replacement of low voltage transformer breakers • Replacement of Protection and Control systems	2028
Douglas Point TS	• Replacement of T3/T4 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems	2028
Hanover TS	• Replacement of T1 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems and CVT's *Additional scope of work currently under development*	2031
Owen Sound TS	• Replacement of T4/T5 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems	2028
	• Replacement of T3 transformer and associated switches • Replacement of low voltage transformer breaker	2031

[1] Scope and dates as of April 2022 and are subject to change

Seaforth TS	• Replacement of 2 autotransformers 230/115 kV • Replacement of 2 step-down transformers 115/27.6 kV • Replacement of 230kV switches • Upgrade Protection and Control systems • Updated AC & DC station service	2024
Wingham TS	• Complete station refurbishment	2023

Based on the needs identified in the region thus far and the transmission sustainment plans listed in Table 7-1, consolidation of sustainment and development needs is not necessary at this time.

8. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER BRUCE-HURON REGION.

Two near and mid-term needs were identified for the Greater Bruce-Huron Region. They are:

I. Transmission Circuit Capacity on L7S (mid-term)

II. Customer delivery point performance review on the 115 kV system

This RIP report addresses both of these needs and has concluded that regional plans are required. Next Steps, Lead Responsibility, and Timeframes for implementing the regional plans to address needs I and II are summarized in the Table 8-1 below.

Table 8-1: Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	In-Service Date	Cost	Needs Mitigated
1	Increase Capacity of Limiting Section of L7S	Assessment of Limiting Section	Hydro One Transmission	2023-2025	$550k - TBD	I
2	Continued assessment of L7S condition to address deteriorating components	Monitor performance & assess condition	Hydro One Transmission	TBD	TBD	II

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Hydro One, "Needs Assessment Report, Greater Bruce-Huron Region", 31 May 2019. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterbrucehuron/Documents/Greater%20Bruce-Huron%20Needs%20Assessment%20Report%20-%20May%202019.pdf

[2] IESO, "Greater Bruce-Huron Scoping Assessment Report", 19 September 2019. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Bruce-Huron/greater-bruce-huron-20190919-scoping-assessment-outcome-report.ashx

[3] IESO, "South Huron-Perth Sub-Region Integrated Regional Resource Planning", September 2021. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Bruce-Huron/Southern-Huron-Perth-IRRP-20210916.ashx

APPENDIX A: STEP-DOWN TRANSFORMER STATIONS IN THE GREATER BRUCE-HURON REGION

Station	Voltage (kV)	Supply Circuits
Bruce HWP B TS	230 kV	B20P/B24P
Douglas Point TS	230 kV	B20P/B24P
Hanover TS	115 kV	B4V/B5V
Owen Sound TS	230 kV	B27S/B28S
Seaforth TS	115 kV	B22D/B23D
Stratford TS	230 kV	B22D/B23D
Wingham TS	230 kV	B22D/B23D
Festival MTS #1	230 kV	B22D/B23D
Palmerston TS	115 kV	D10H
Goderich TS	115 kV	61M18
Constance DS	115 kV	61M18
St. Marys TS	115 kV	L7S
Customer CTS #1	115 kV	L7S
Centralia TS	115 kV	L7S
Grand Bend East DS	115 kV	L7S
Customer CTS #2	115 kV	L7S
Customer CTS #3	115 kV	L7S
Customer CTS #4	115 kV	L7S

APPENDIX B: REGIONAL TRANSMISSION CIRCUITS IN THE GREATER BRUCE-HURON REGION

Location	Circuit Designation	Voltage (kV)
Bruce A TS – Orangeville TS	B4V/B5V	230 kV
Bruce A TS – Detweiler TS	B22D/ B23D	230 kV
Bruce A TS – Owen Sound TS	B27S/B28S	230 kV
Bruce A TS – Douglas Point TS	B20P/B24P	230 kV
Hanover TS – Palmerston TS	D10H-North	115 kV
Seaforth TS – Goderich TS	61M18	115 kV
Seaforth TS – St. Marys TS	L7S	115 kV
Owen Sound TS – Hanover TS	S1H	115 kV

APPENDIX C: DISTRIBUTORS IN THE GREATER BRUCE-HURON REGION

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc.	Constance DS	Tx
	Centralia TS	Dx
	Grand Bend East DS	Tx
	Douglas Point TS	Dx
	Goderich TS	Dx
	Hanover TS	Dx
	Owen Sound TS	Dx
	Palmerston TS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Wingham TS	Dx
Entegrus Powerlines Inc.	Centralia TS	Dx
ERTH Power Corporation	Constance DS	Dx
	Goderich TS	Dx
	Seaforth TS	Dx
	Stratford TS	Dx
Festival Hydro Inc.	Grand Bend East DS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Festival MTS #1	Tx
Lake Huron Primary Water Supply System	Lake Huron WTP CTS	Tx
Lake Huron Primary Water Supply System	McGillivray R&BP CTS	Tx
Wellington North Power Inc.	Hanover TS	Dx
	Palmerston TS	Dx
Westario Power Inc.	Douglas Point TS	Dx
	Hanover TS	Dx
	Palmerston TS	Dx
	Wingham TS	Dx
Enbridge Pipeline Inc.	Enbridge Bryanston CTS	Tx
St. Marys Cement Inc.	St. Marys Cement CTS	Tx

APPENDIX D: REGIONAL LOAD FORECAST (2019-2028)

Table D-1. Gross Winter Regional-Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	28.0	25.6	25.8	26.0	26.2	26.4	26.6	26.8	27.0	27.2
Centralia TS	65.4	30.6	33.6	33.9	37.0	37.3	37.5	37.7	37.9	38.1	38.3
Douglas Point TS	109.8	62.4	76.3	82.4	89.1	88.9	88.6	88.3	88.0	87.7	87.5
Goderich TS	132.0	31.3	31.7	34.7	36.8	37.2	37.5	37.8	38.1	38.4	38.7
Hanover TS	124.7	68.8	70.1	70.7	72.4	73.2	74.8	75.4	76.0	76.7	77.3
Owen Sound TS	232.5	109.6	111.5	112.4	113.3	114.5	115.1	115.7	116.4	117.2	117.9
Palmerston TS	147.2	70.1	73.4	75.0	77.8	78.7	79.6	80.3	81.0	81.7	82.5
Seaforth TS	55.4	28.7	30.8	31.0	31.3	31.5	31.6	31.8	32.1	32.3	32.5
St. Marys TS	59.0	21.9	21.9	22.0	22.2	22.3	22.3	22.4	22.5	22.5	22.6
Stratford TS	128.6	68.5	70.5	71.0	72.9	73.5	74.0	74.4	75.0	75.5	76.0
Wingham TS	107.9	40.5	42.3	46.6	51.9	52.4	52.8	53.1	53.5	53.9	54.4
Constance DS	35.0	16.8	17.0	17.1	17.1	17.2	17.3	17.3	17.4	17.5	17.5
Grand Bend East DS	NA	11.8	12.6	13.2	13.3	13.4	13.5	13.6	13.6	13.7	13.8
Bruce Power HWB TS	114.8	10.4	11.2	11.1	10.9	10.8	10.6	10.5	10.3	10.3	10.3
Customer CTS #1	NA	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Customer CTS #2	NA	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Customer CTS #3	NA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Customer CTS #4	NA	13.8	13.8	13.8	18.4	18.4	18.4	18.4	18.4	23.0	23.0

Table D-2. Gross Summer Regional-Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	25.0	25.2	25.4	25.5	25.7	25.9	26.1	26.3	26.5	26.7
Centralia TS *	61.1	29.9	33.2	34.0	36.0	37.0	37.0	37.0	37.0	37.0	38.0
Douglas Point TS	97.2	51.0	60.6	69.7	77.6	78.6	79.5	80.4	81.3	82.3	83.3
Goderich TS	126.5	31.8	32.2	35.2	37.2	37.6	37.9	38.2	38.5	38.8	39.1
Hanover TS	109.9	75.9	78.5	80.4	83.7	85.8	88.9	90.9	93.0	95.2	97.5
Owen Sound TS	208.5	92.7	94.8	95.7	96.7	97.8	98.4	98.9	99.5	100.1	100.8
Palmerston TS	132.2	52.3	55.0	57.3	58.4	59.2	60.0	60.5	61.1	61.8	62.4
Seaforth TS	45.1	29.7	32.1	32.6	33.2	33.7	34.3	34.8	35.3	35.9	36.5
St. Marys TS *	52.8	22.7	22.9	25.0	26.0	26.0	26.0	26.0	26.0	27.0	27.0
Stratford TS	117.3	73.6	75.7	76.3	78.2	78.9	79.4	79.9	80.5	81.0	81.6
Wingham TS	97	36.9	38.8	44.7	52.2	52.4	52.4	52.4	52.5	52.7	52.8
Constance DS	25	17.4	17.7	17.8	17.9	18.0	18.1	18.1	18.2	18.2	18.3
Grand Bend East DS *	NA	16.5	17.3	16.0	16.0	16.0	16.0	16.0	17.0	17.0	17.0
Bruce Power HWB TS	113.2	4.3	4.6	4.6	4.5	4.5	4.4	4.3	4.3	4.3	4.3
Customer CTS #1 *	NA	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Customer CTS #2 *	NA	5.0	5.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Customer CTS #3 *	NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer CTS #4 *	NA	13.9	13.9	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0

*Updated to align with South Huron-Perth IRRP Forecast

Table D-3. Gross Winter Non-Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	29.7	27.2	27.4	27.6	27.8	28.1	28.3	28.5	28.7	28.9
Centralia TS	65.4	33.3	36.7	36.9	40.4	40.7	40.9	41.1	41.3	41.6	41.8
Douglas Point TS	109.8	63.1	77.2	83.3	90.2	89.9	89.6	89.3	89.0	88.7	88.5
Goderich TS	132.0	35.8	36.2	39.7	42.1	42.4	42.8	43.1	43.5	43.8	44.2
Hanover TS	124.7	72.0	73.4	74.0	75.8	76.6	78.3	78.9	79.5	80.2	80.9
Owen Sound TS	232.5	109.9	111.9	112.8	113.7	114.8	115.5	116.1	116.8	117.6	118.3
Palmerston TS	147.2	70.3	73.7	75.3	78.1	79.0	79.9	80.6	81.3	82.0	82.8
Seaforth TS	55.4	34.8	37.3	37.5	37.9	38.1	38.3	38.6	38.8	39.1	39.3
St. Marys TS	59.0	23.7	23.7	23.8	23.9	24.0	24.1	24.2	24.3	24.3	24.4
Stratford TS	128.6	71.9	74.0	74.5	76.5	77.1	77.6	78.1	78.7	79.2	79.8
Wingham TS	107.9	62.6	65.3	71.9	80.2	81.0	81.5	82.1	82.7	83.3	84.0
Constance DS	35.0	16.9	17.1	17.2	17.3	17.4	17.4	17.4	17.5	17.6	17.6
Grand Bend East DS	NA	13.0	14.0	14.6	14.7	14.9	14.9	15.0	15.1	15.2	15.3
Bruce Power HWB TS	114.8	12.1	13.0	12.8	12.7	12.5	12.3	12.1	12.0	12.0	12.0
Customer CTS #1	NA	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Customer CTS #2	NA	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Customer CTS #3	NA	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Customer CTS #4	NA	15.0	15.0	15.0	20.0	20.0	20.0	20.0	20.0	25.0	25.0

Table D-4. Gross Summer Non-Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	32.6	32.9	33.1	33.4	33.6	33.9	34.1	34.4	34.6	34.9
Centralia TS *	61.1	34.5	38.2	37.0	40.0	41.0	41.0	41.0	41.0	42.0	42.0
Douglas Point TS	97.2	51.2	60.8	70.0	77.9	78.9	79.8	80.7	81.6	82.6	83.6
Goderich TS	126.5	38.2	38.7	42.2	44.7	45.2	45.5	45.9	46.2	46.6	47.0
Hanover TS	109.9	75.9	78.5	80.4	83.7	85.8	88.9	90.9	93.0	95.2	97.5
Owen Sound TS	208.5	104.1	106.4	107.4	108.6	109.9	110.5	111.1	111.7	112.4	113.1
Palmerston TS	132.2	62.6	65.8	68.5	69.9	70.9	71.8	72.4	73.2	73.9	74.7
Seaforth TS	45.1	31.4	33.9	34.4	35.0	35.6	36.2	36.7	37.3	37.9	38.5
St. Marys TS *	52.8	24.9	25.1	28.0	28.0	28.0	28.0	28.0	29.0	29.0	29.0
Stratford TS	117.3	82.2	84.5	85.2	87.3	88.0	88.6	89.2	89.8	90.5	91.1
Wingham TS	97	51.2	53.9	62.1	72.5	72.7	72.7	72.8	72.9	73.1	73.3
Constance DS	25	18.2	18.4	18.5	18.6	18.8	18.8	18.9	18.9	19.0	19.1
Grand Bend East DS *	NA	22.1	23.1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Bruce Power HWB TS	113.2	8.3	8.9	8.8	8.7	8.6	8.4	8.3	8.2	8.2	8.2
Customer CTS #1 *	NA	3.4	3.4	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Customer CTS #2 *	NA	5.8	5.8	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Customer CTS #3 *	NA	4.5	4.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Customer CTS #4 *	NA	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0

*Updated to align with South Huron-Perth IRRP Forecast

Table D-5. Net Winter Regional Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	27.7	25.2	25.7	25.8	25.5	25.5	25.5	25.6	25.6	25.7
Centralia TS	65.4	30.3	32.8	33.0	36.0	35.5	35.5	35.4	35.4	35.4	35.4
Douglas Point TS	109.8	47.7	61.0	67.9	74.3	72.5	71.5	70.7	70.0	69.2	80.7
Goderich TS	132.0	31.0	31.2	34.1	36.0	35.6	35.6	35.6	35.7	36.2	36.3
Hanover TS	124.7	50.5	51.3	52.8	54.2	53.6	54.6	54.7	54.9	55.1	55.3
Owen Sound TS	232.5	108.5	109.7	107.9	108.4	107.5	107.4	107.3	107.4	111.0	111.2
Palmerston TS	147.2	69.4	72.3	74.1	76.6	76.1	76.4	76.6	76.9	77.2	77.5
Seaforth TS	55.4	17.8	19.6	20.2	20.3	19.9	19.8	19.7	19.7	19.7	19.7
St. Marys TS	59.0	21.7	21.5	21.8	21.9	21.6	21.4	21.4	21.3	21.3	21.2
Stratford TS	128.6	67.9	69.4	69.5	71.1	70.3	70.2	70.3	70.4	70.4	70.5
Wingham TS	107.9	40.1	41.6	33.6	38.6	37.7	37.5	37.3	37.3	37.2	37.2
Constance DS	35.0	16.7	16.7	16.9	16.9	16.7	16.7	16.6	16.6	16.5	16.5
Grand Bend East DS	NA	11.7	12.4	12.0	12.1	11.9	11.9	11.9	11.9	11.9	11.9
Bruce Power HWB TS	114.8	10.3	11.0	11.0	10.8	10.5	10.2	10.0	9.8	9.7	9.7
Customer CTS #1	NA	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.5	2.5
Customer CTS #2	NA	3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Customer CTS #3	NA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Customer CTS #4	NA	13.7	13.6	13.6	18.1	18.0	17.9	17.9	17.9	22.3	22.2

Table D-6. Net Summer Regional Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	24.7	24.7	25.0	24.9	24.7	24.7	24.6	24.6	24.5	24.5
Centralia TS *	61.1	29.6	32.4	31.6	33.3	33.8	33.5	33.2	33.0	32.6	33.4
Douglas Point TS	97.2	36.0	45.0	54.4	61.6	61.7	62.0	62.3	62.7	63.1	75.6
Goderich TS	126.5	31.5	31.7	34.0	35.7	35.6	35.5	35.5	35.5	35.9	36.0
Hanover TS	109.9	56.1	58.1	60.5	63.0	64.2	66.5	67.8	69.3	70.7	72.3
Owen Sound TS	208.5	90.0	91.1	88.8	88.9	88.9	88.5	88.3	88.2	91.5	91.5
Palmerston TS	132.2	51.8	54.0	54.8	55.4	55.4	55.6	55.6	55.7	55.8	56.0
Seaforth TS	45.1	17.9	20.1	20.8	21.0	21.2	21.4	21.7	22.0	22.3	22.6
St. Marys TS *	52.8	22.4	22.5	24.2	25.0	24.7	24.5	24.3	24.1	24.9	24.7
Stratford TS	117.3	72.8	74.4	73.6	74.8	74.5	74.3	74.2	74.1	74.0	74.0
Wingham TS	97	23.6	25.2	31.1	37.9	37.3	36.7	36.3	35.9	35.5	35.2
Constance DS	25	17.3	17.4	17.2	17.1	17.0	16.9	16.9	16.8	16.7	16.7
Grand Bend East DS *	NA	15.1	15.7	14.5	14.3	14.0	13.9	13.7	14.6	14.4	14.3
Bruce Power HWB TS	113.2	4.3	4.6	4.5	4.3	4.2	4.1	4.0	3.9	3.8	3.8
Customer CTS #1 *	NA	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Customer CTS #2 *	NA	4.9	4.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.8
Customer CTS #3 *	NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer CTS #4 *	NA	13.8	13.7	12.7	12.6	12.5	12.5	12.4	12.4	12.2	12.1

*Updated to align with South Huron-Perth IRRP Forecast

Table D-7. Net Winter Non-Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	29.5	26.8	27.3	27.4	27.1	27.1	27.2	27.2	27.3	27.4
Centralia TS	65.4	33.0	35.8	36.1	39.3	38.9	38.8	38.8	38.8	38.8	38.9
Douglas Point TS	109.8	48.5	61.8	68.9	75.3	73.5	72.6	71.8	71.0	70.3	81.7
Goderich TS	132.0	35.4	35.6	39.0	41.2	40.8	40.9	41.0	41.1	41.6	41.8
Hanover TS	124.7	53.7	54.5	56.1	57.5	57.0	58.1	58.2	58.5	58.7	59.0
Owen Sound TS	232.5	108.9	110.1	108.3	108.8	107.9	107.8	107.7	107.8	111.4	111.6
Palmerston TS	147.2	69.7	72.5	74.4	76.9	76.4	76.7	76.9	77.2	77.5	77.8
Seaforth TS	55.4	23.9	26.0	26.7	26.9	26.5	26.4	26.5	26.5	26.5	26.6
St. Marys TS	59.0	23.4	23.3	23.6	23.7	23.3	23.2	23.2	23.1	23.1	23.1
Stratford TS	128.6	71.2	72.8	73.0	74.7	73.9	73.9	74.0	74.1	74.1	74.3
Wingham TS	107.9	49.4	51.6	59.0	66.9	66.2	66.2	66.3	66.5	66.6	66.8
Constance DS	35.0	16.8	16.8	17.0	17.1	16.8	16.8	16.7	16.7	16.7	16.6
Grand Bend East DS	NA	12.9	13.8	13.4	13.5	13.4	13.4	13.4	13.4	13.4	13.4
Bruce Power HWB TS	114.8	11.9	12.8	12.8	12.6	12.2	11.9	11.7	11.5	11.4	11.3
Customer CTS #1	NA	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Customer CTS #2	NA	5.8	5.8	5.8	5.8	5.8	5.8	5.7	5.7	5.7	5.7
Customer CTS #3	NA	4.6	4.6	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Customer CTS #4	NA	14.9	14.8	14.7	19.6	19.6	19.5	19.5	19.4	24.2	24.2

Table D-8. Net Summer Non-Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	32.3	32.3	32.8	32.7	32.6	32.6	32.6	32.7	32.7	32.7
Centralia TS *	61.1	34.1	37.3	34.6	37.3	37.8	37.5	37.2	37.0	37.6	37.4
Douglas Point TS	97.2	50.7	59.7	54.7	61.8	62.0	62.3	62.6	63.0	63.4	75.9
Goderich TS	126.5	37.8	38.1	41.1	43.2	43.2	43.2	43.2	43.3	43.8	43.9
Hanover TS	109.9	56.1	58.1	60.5	63.0	64.2	66.5	67.8	69.3	70.7	72.3
Owen Sound TS	208.5	101.3	102.5	100.6	100.8	100.9	100.6	100.4	100.4	103.9	103.9
Palmerston TS	132.2	62.0	64.7	66.1	66.9	67.1	67.4	67.5	67.8	68.0	68.3
Seaforth TS	45.1	19.6	21.9	22.6	22.9	23.1	23.3	23.6	24.0	24.3	24.6
St. Marys TS *	52.8	24.6	24.7	27.2	27.0	26.7	26.5	26.3	27.1	26.9	26.7
Stratford TS	117.3	81.3	83.1	82.4	83.9	83.6	83.5	83.5	83.5	83.5	83.5
Wingham TS	97	50.7	53.0	48.5	58.1	57.6	57.0	56.6	56.3	56.0	55.7
Constance DS	25	18.0	18.1	17.9	17.9	17.8	17.7	17.6	17.5	17.5	17.4
Grand Bend East DS *	NA	21.9	22.7	20.5	20.3	20.0	19.9	19.7	19.6	19.4	19.3
Bruce Power HWB TS	113.2	8.2	8.8	8.7	8.5	8.3	8.1	7.9	7.8	7.7	7.7
Customer CTS #1 *	NA	3.4	3.3	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Customer CTS #2 *	NA	5.7	5.7	6.9	6.9	6.9	6.8	6.8	6.8	6.8	6.8
Customer CTS #3 *	NA	4.5	4.5	4.9	4.9	4.9	4.9	4.9	4.9	4.8	4.8
Customer CTS #4 *	NA	14.8	14.7	14.7	14.6	14.5	14.5	14.4	14.4	14.1	14.1

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DER	Distributed Energy Resources
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

APPENDIX D. IRRP Report 2021 Southern Huron Perth Sub Region

Southern Huron-Perth Sub-Region Integrated Regional Resource Plan

Part of the Greater Bruce/Huron Planning Region

September 2021

ieso
Connecting Today.
Powering Tomorrow.

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List of Abbreviations

CDM	Conservation Demand Management
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
FIT	Feed-in Tariff
GDP	Gross Domestic Product
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TS	Transformer Station
Working Group	Technical Working Group of the Southern Huron-Perth sub-region

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Southern Huron-Perth sub-region which included the following members:

- Entegrus Powerlines Inc.
- Festival Hydro
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator

The Working Group assessed the adequacy of electricity supply to customers in the Southern Huron-Perth sub-region over a 20-year period beginning in 2019; developed a plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Southern Huron-Perth Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

The Southern Huron-Perth Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1 Introduction

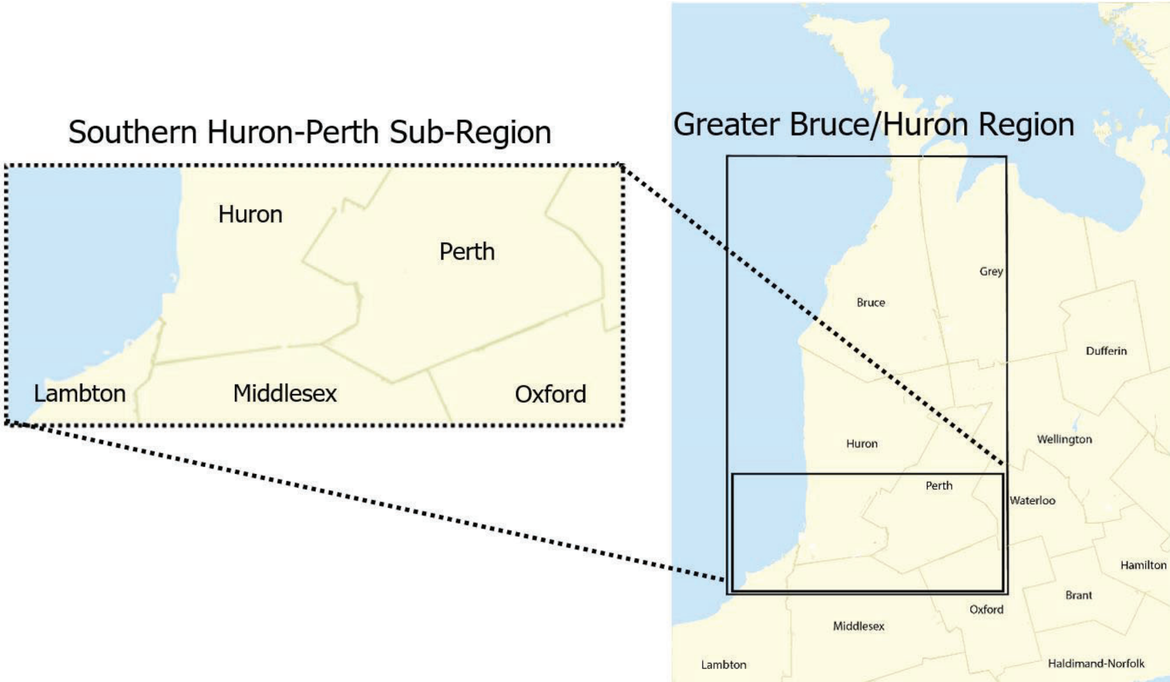
This Integrated Regional Resource Plan (IRRP) addresses the regional electricity needs for the Southern Huron-Perth sub-region for the next 20 years (the "study period").

Southern Huron-Perth is a sub-region of the Greater Bruce/Huron region. The Greater Bruce/Huron region is located in southwestern Ontario and comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties.

Several Indigenous communities reside in the sub-region or may have interests in the sub-region, including Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Chippewas of the Thames, Nawash First Nation, Saugeen First Nation, Historic Saugeen Métis, MNO Great Lakes Métis Council, Six Nations of the Grand River and Haudenosaunee Chiefs Confederacy Council.

The Scoping Assessment recommended a focused IRRP for the Southern Huron-Perth sub-region. This sub-region consists of the area supplied by the 115 kV circuit L7S, which includes municipalities of Bluewater, South Huron, Lambton Shores, Lucan-Biddulph, Middlesex Centre, North Middlesex, Thames Centre, Zorra, Perth South, Town of St. Marys, and West Perth. The approximate geographical boundaries of the sub-region are shown in Figure 1.1.

Figure 1.1 | Map of the Southern Huron-Perth Sub-Region



The Southern Huron-Perth sub-region is summer peaking and is served via 115 kV circuit L7S from Seaforth TS and a local wind farm. These facilities supply seven local load stations, including Centralia TS, Grand Bend East DS, St. Marys TS, and four customer transformer stations (CTS). The sub-region has an alternate supply point via 115 kV circuit D8S, which connects a portion of St. Marys TS to Detweiler TS in the adjacent Kitchener-Waterloo-Cambridge-Guelph region under normal operating conditions. The electricial system is illustrated in Figure 1.2 and the single line diagram in Figure 1.3.

Figure 1.2 | Electricity Infrastructure in the Southern Huron-Perth Sub-Region[1]

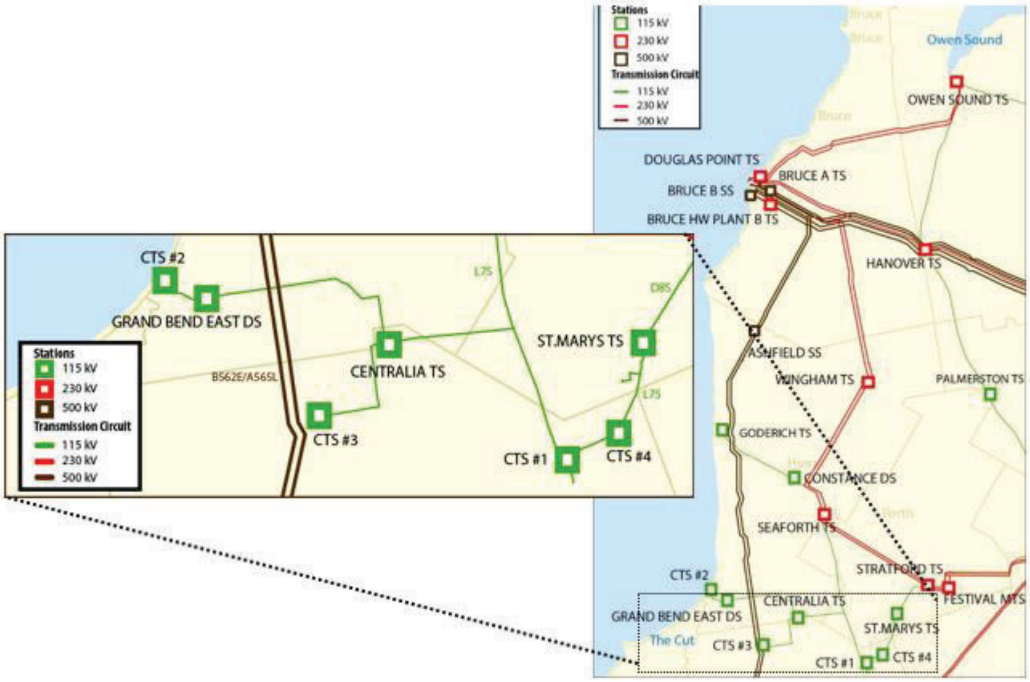
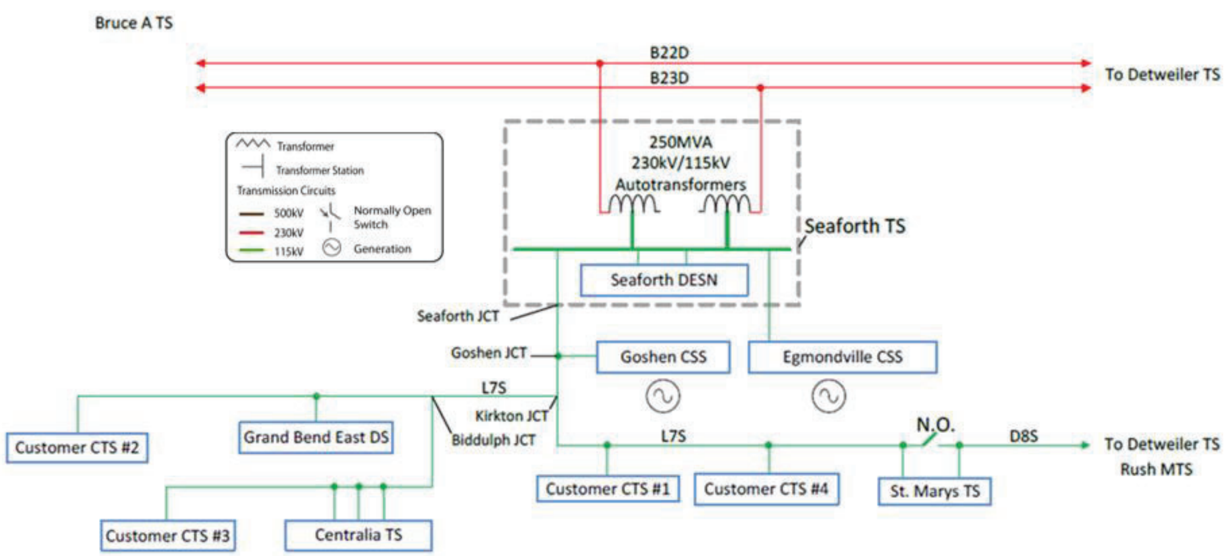


Figure 1.3 | Single Line Diagram of the Southern Huron-Perth Sub-Region, exclusive of the 230 kV system



Development of the Southern Huron-Perth IRRP was initiated in September 2019 following the publication of Hydro One's Needs Assessment report on May 31, 2019 and, subsequently, the IESO's Scoping Assessment Outcome Report and Terms of Reference on Sept 19, 2019, which identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

[1] The region is defined by electricity infrastructure; geographical boundaries are approximate.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, including the Southern Huron-Perth sub-region, at least once every five years. The process allows a regional planning cycle to be triggered before the five-year mark due to material changes such as demand or resource changes. The active part of this cycle is made up of Needs Assessment, Scoping Assessment, IRRP, and Regional Infrastructure Plan (RIP) stages, which take up approximately half of the typical five-year timeframe. In many regions, this period of active planning is followed by a period when plan implementation begins, and the Working Group monitors demand trends until the next cycle begins. The complexity of issues requires the Working Group to continue to be engaged in integrated planning throughout the regional planning cycle, after the completion of the IRRP.

Further information on the process can be found in Appendix C. The IESO has also recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

The last regional planning cycle for the Greater Bruce/Huron region did not identify any needs requiring regional coordination and proceeded to three seperate local plans, the last of which was conlcuded in May 2017, and was further consolidated and documented in a RIP for the region in August 2017, resulting in two recommendations which have since been completed. Those recommendations were: i) to install spacers and ground rods along the L7S circuit, and ii) to install motorized switches on L7S at Kirkton junction, Biddulph junction and St Marys TS, both of which are meant to enhance the delivery point performance for L7S and improve the performance reliability by reducing outage duration.

In addition to the needs reviewed in this IRRP for the Southern Huron-Perth sub-region, a few near-term end-of-life asset replacement needs were identified for the broader Greater Bruce/Huron region and proceeded to local planning. As well, an identified voltage issue at Hanover TS for the loss of 230 kV circuits B4V/B5V will be investigated in a subsequent bulk study. These outcomes were captured in the Greater Bruce/Huron Scoping Assessment.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement to date and moving forward is provided in Section 8; and
- A conclusion is provided in Section 0.

2 The Integrated Regional Resource Plan

The Southern Huron-Perth IRRP provides recommendations to address the electricity needs for the region over the next 20 years based on application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). The needs were identified over three main planning horizons: from the base year when the forecast was originated (2019) through the near term (up to an including 2023), medium term (six to 10 years, from 2024 to 2028 inclusive), and long-term (11 to 20 years, or from 2029 to 2038). These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. The recommendations have been developed in consideration of a number of factors including reliability, cost, technical feasibility, environmental and social factors, and maximization of the use of the existing electricity system, where it is economic to do so.

The Needs Assessment identified a capacity need in this sub-region, however, given changes to customers' growth plans, the triggering loads for that need were deferred with no firm in-service date. In order to conduct a fulsome long-term plan, two forecast scenarios were developed and evaluated for the purposes of this IRRP: i) a Reference Scenario and ii) a High Growth Scenario. The Reference Scenario represents the firm load requests and projected residential and commercial growth, while the High Growth Scenario also includes the industrial loads initially projected, but shifted to the mid- to long-term to determine what may be required if/when that load materializes.

The following sections provide details of the needs and recommendations to address the identified need under both scenarios.

2.1 Reference Scenario Needs

Based on the IRRP load forecast and ongoing work in the area, no needs have been identified under the Reference Scenario.

2.2 High Growth Scenario Needs

While no needs have been identified under the Reference Scenario, potential long-term supply capacity needs were identified under the High Growth Scenario. In 2035, flows on circuit L7S exceed its thermal ratings following the loss of D8S, the 115 kV circuit from Detweiler TS to St Marys TS, which forms the only other supply circuit into the Southern Huron-Perth sub-region. Approximately, 11 MW of supply is needed to mitigate the overload. Considering outage conditions, in 2030, flows on L7S exceed its thermal ratings for the loss of Seaforth T6, one of the two autotransformers at Seaforth TS, under an outage to D8S. Both of these contingencies result in all loads within the Southern Huron-Perth sub-region being supplied via L7S.

A combination of conservation and demand management (CDM) beyond what is committed and planned through existing provincial and federal programs, along with distribution load transfers, could resolve the High Growth needs identified. These are both cost-effective measures that could be implemented within one to three years, as required. At this time, none of the supply capacity needs identified over the long term require early development work for major infrastructure projects in the Southern Huron-Perth sub-region. There may be opportunities for communities and local utilities to manage their future electricity demand through the development of community-based solutions that may evolve between planning cycles.

When load levels are within approximately 4 MW of the sub-region's supply capacity, projected to occur within the next 5 years based on the Reference scenario, CDM programs can be pursued and load transfers can be implemented to bridge any potential gap.

The Working Group will continue to monitor load growth in this area and re-evaluate these needs periodically, including in the next regional planning cycle, to take action as necessary when load tends towards the High Growth Scenario to ensure there are no reliability impacts.

Recognizing the most cost-effective solution involves additional conservation, the Working Group should also seek regulatory clarity on implementation mechanisms for this solution type in advance of the long-term need materializing, noting that multiple LDCs are supplied by the L7S circuit (i.e., would require clarification of approach if existing CDM Guidelines were to be leveraged for implementation) and the opportunity to leverage some existing mechanisms (i.e., the Local Initiatives Program) may or may not align with when the need materializes.

2.3 Conservation and Demand Management

Conservation is important in managing demand in Ontario and plays a key role in maximizing the utilization of existing infrastructure and maintaining a reliable supply of electricity.

As part of the reference forecast, conservation savings from codes and standards and the 2019-2020 CDM programs were accounted for, based on the best known information at the time.

Following the development of the planning forecast, on September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework, which follows the conclusion of the 2019-2020 Interim Framework. The new 2021-2024 CDM Framework will focus on cost-effectively meeting the needs of Ontario's electricity system, including by focusing on the achievement of provincial peak demand reductions, as well as targeted approaches to address regional and/or local electricity system needs. The savings that will be achieved through the 2021-2024 CDM Framework will help reduce supply capacity needs identified under the High Growth scenario.

In addition, there is the opportunity for up to 16.1 MW in further peak CDM savings that could be achieved in this sub-region, based on the 2019 Achievable Potential Study.

It is recommended that the Working Group monitor the progress of the 2021-2024 CDM Framework and the contribution of savings from its programs to reducing net demand in the region, and to explore the opportunity for participation in the Local Initiatives Program as an option to help address needs in the long term.

In addition, the IESO's Indigenous Community Energy Plan Program supports First Nation and Métis communities and organizations to develop and maintain an updated community energy plan designed to enhance community energy security. The IESO is also working with Indigenous communities to develop their community energy plan, which documents the communities' energy baseline and analyses and recommends efficiency and conservation measures and retrofits.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region.

The process consists of four main components:

- A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
- A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
- An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
- A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix C.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.2 Southern Huron-Perth and IRRP Development

The process to develop the Southern Huron-Perth IRRP was initiated following the release of the Needs Assessment report for the region by Hydro One in May 2019 and the subsequent Scoping Assessment report produced by the IESO in September 2019, which recommended needs identified for the Southern Huron-Perth sub-region be further pursued through an IRRP. This was due to the potential for coordinated solutions and non-wires alternatives. Shortly after, the Working Group was formed to develop terms of reference for the IRRP, gather data, identify near- to long-term needs in the area, and recommend near- to long-term solutions. In September 2020, the Scoping Assessment was revised and reissued to reflect changes to the study scope and timelines.

4 Background and Study Scope

This is the second cycle of regional planning for the Greater Bruce/Huron region. The first cycle of regional planning started in February 2016 with the Needs Assessment, and proceeded to local planning. In August 2016, a Regional Infrastructure Plan (RIP) was published that summarized findings from local planning, and reviewed new needs from updated load forecasts in the Kincardine area. The Local Planning Report and RIP recommended:

- Monitoring loading on L7S and increasing the emergency rating once loading approaches capacity;
- A two-stage plan (to install spacers and ground rods along the L7S circuit, and to install motorized switches on L7S) to reduce frequency and duration of interruptions due to adverse weather; and
- Monitoring load growth in the Kincardine area to identify any potential step-down transformation capacity needs at Douglas Point TS.

The 2019 Needs Assessment identified that under outage conditions, L7S – the 115 kV circuit that provides supply to Southern Huron-Perth through Seaforth TS – would be thermally overloaded by 2022, when the emergency rating will be exceeded with D8S out of service. Under all elements in service conditions, the circuit would be thermally overloaded by 2027. As such, Hydro One initiated a project to increase the sag clearance of limiting sections from Seaforth to Kirkton junction, scheduled for 2021/2022, which partly addressed the identified supply capacity need.

Even after Hydro One increases the sag clearance of the limiting section, there is still a remaining supply capacity need on L7S circuit requiring further regional coordination and, hence, an IRRP was initiated, focused on the Southern Huron-Perth sub-region. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019.

4.1 Study Scope

This IRRP develops and recommends options to meet the supply needs of the Southern Huron-Perth sub-region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, CDM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The needs addressed in this IRRP include adequacy, security, and relevant end-of-life asset considerations.

The following transmission facilities were included in the scope of this study:

- **115 kV connected stations:** Seaforth TS, Grand Bend East DS, Centralia TS, St Marys TS and four customer-connected transformer stations;
- **115 kV transmission lines:** L7S, D8S; and
- **230/115 kV autotransformers:** Seaforth TS T1/T2.

Supply to the Southern Huron-Perth sub-region is provided from the broader Greater Bruce/Huron region through the autotransformers at Seaforth TS, which connect to the 115 kV circuit L7S, and the 115 kV circuit D8S, connected to the adjacent Kitchener/Waterloo/Cambridge/Guelph region through Detweiler TS.

The Southern Huron-Perth IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with transmission asset owners, along with other relevant asset demographic information;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

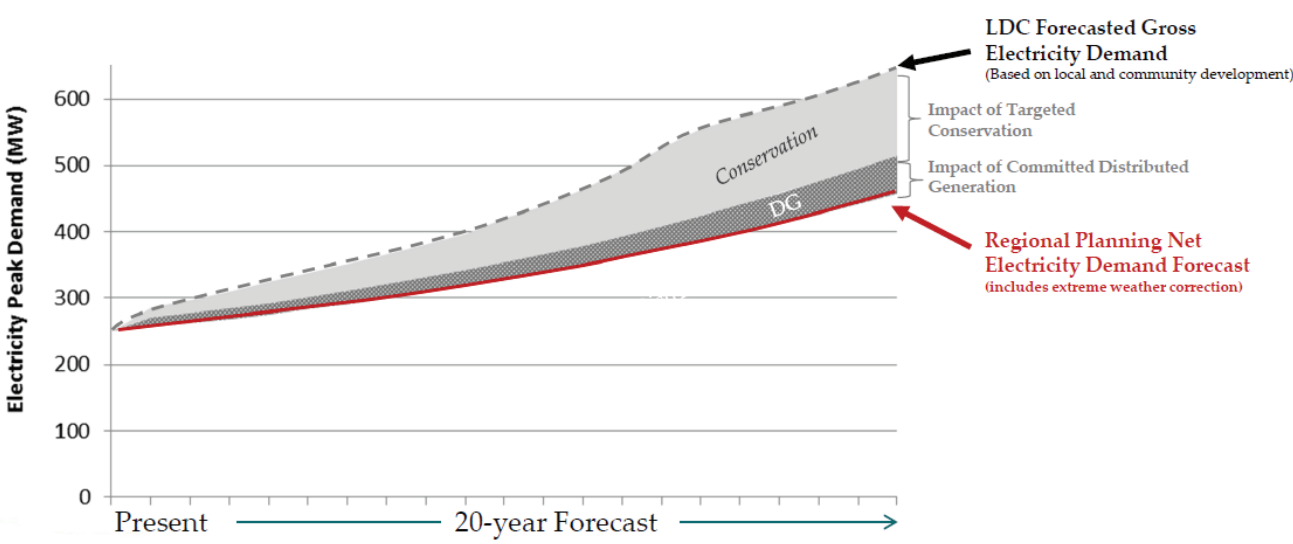
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. This section describes the specific details of the development of the demand forecast for the Southern Huron-Perth sub-region. It highlights the assumptions made for peak demand forecasts, including the contribution of conservation and distributed generation (DG) to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon as explained in the next section.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum, also called the coincident peak demand. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether the stations' peaks occur at different times. Within the Southern Huron-Perth sub-region, the peak loading hour for each year occurs in the summer.

5.1 Demand Forecast Methodology

For the purpose of this IRRP, a 20-year regional peak demand forecast was developed to assess supply and reliability needs for the Southern Huron-Perth sub-region. The steps taken to perform this are depicted in Figure 5.1. Gross demand forecasts, which assume the weather conditions of an average year based on historical data and referred to normal weather, were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of the 2019-2020 provincial conservation programs and future savings from codes and standards, as well as DG contracted through provincial programs such as FIT and microFIT, and then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This forecast was then used to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix A.

Figure 5.1 | Development of Demand Forecast

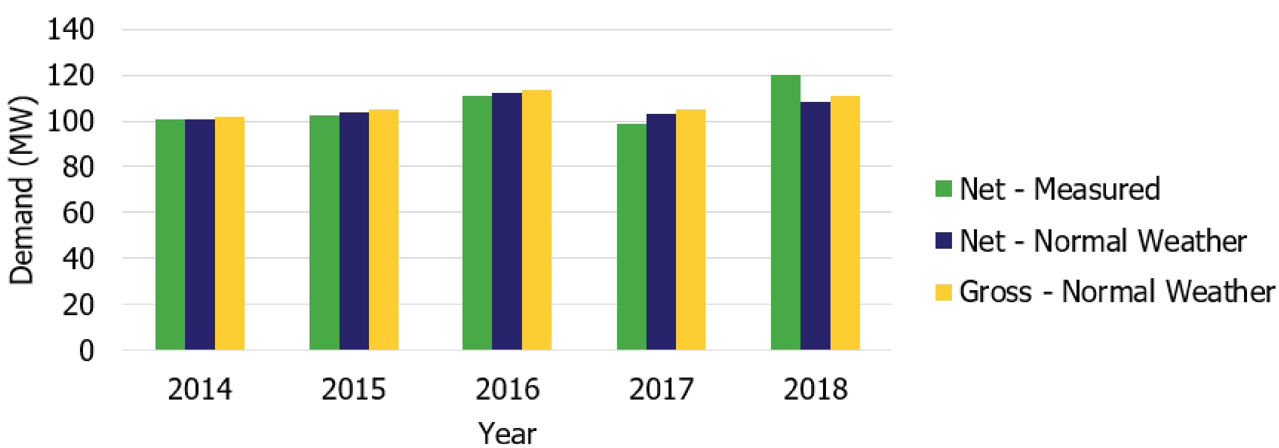


5.2 Historical Electricity Demand

The Southern Huron-Perth sub-region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to building materials manufacturing. While the industrial and commercial sector is the largest consumer of electricity, high-energy-consuming end uses such as air conditioning also play a significant role in contributing to peak electricity demand. During the summer months, peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of high temperatures. More recently, there has been a shift towards increased residential growth in various parts of the sub-region, primarily driven from nearby urban centers (City of London, Region of Waterloo and City of Guelph), stemming from workplace flexibility as a result of the COVID-19 pandemic.

As shown in Figure 5.2, the historical summer peak demand has fluctuated between 100 MW to 120 MW in the recent years. This figure also shows the weather corrected net and gross coincident peak demand for normal weather. The gross demands on the station level in 2018 were the reference starting points for LDCs to forecast their 20-year gross demand as discussed in the next section. Note, the net measure load in 2018 was significantly higher than expected, driven by unseasonably hot summer conditions resulting in higher campground and trailer park load over the Canada Day long weekend, as well as load that was transferred to Grand Bend East DS. This was accounted for through the weather correction and an adjustment made to the reference starting point to account for the load transfer.

Figure 5.2 | Measured & Weather Corrected Coincident Net and Gross Historical Peak Demand in the Southern Huron-Perth sub-region



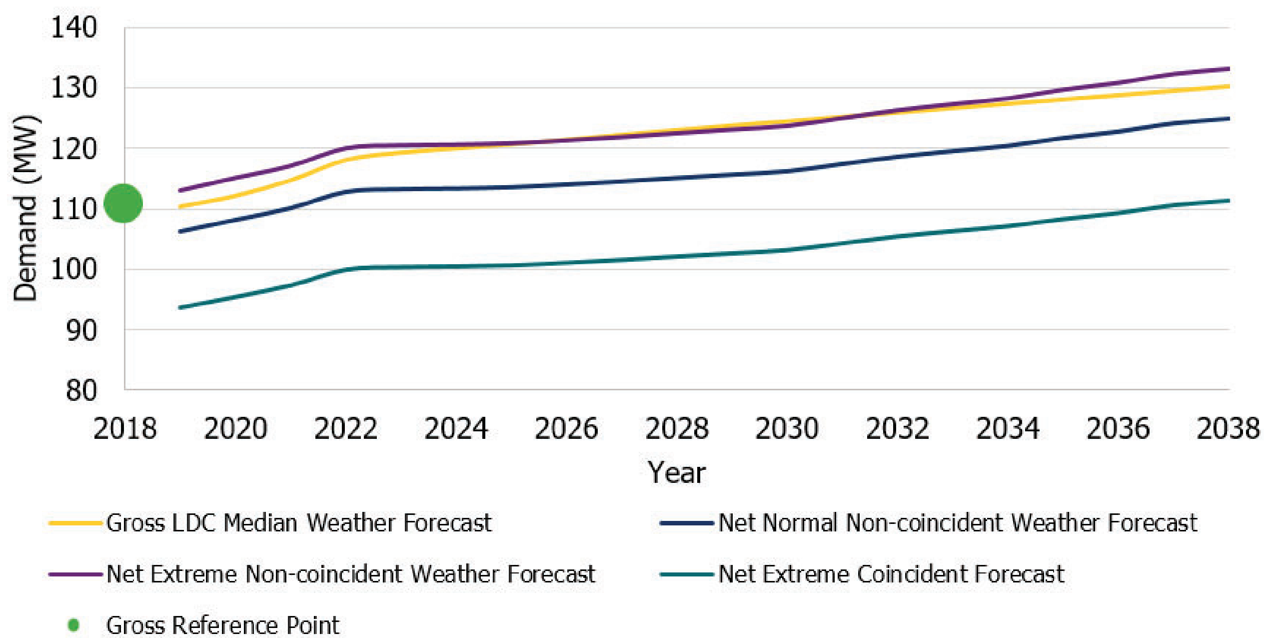
5.3 Gross and Net Demand Forecast

Each participating LDC in the Southern Huron-Perth sub-region prepared gross non-coincident demand forecasts at the station level, or at the station bus level for multi-bus stations. Gross demand forecasts account for increases in demand from new or intensified development. LDCs are expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, or "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and conservation programs, which will be accounted for by the IESO as discussed in Section 5.1.

LDCs have the best information on customer and regional growth expectations in the near and medium term, since they have the most direct involvement with their customers. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. More details on the LDCs' load forecast assumptions can be found in Appendix A.

Figure 5.3 shows the total gross non-coincident demand forecast in the next 20 years as provided by LDCs, based on the IESO's reference point for normal weather. Figure 5.3 also shows the net non-coincident normal weather forecast compiled by the IESO, which accounts for the impacts of conservation and DG on peak demand, along with the IESO's net non-coincident demand forecasts corrected to extreme weather, referred to as the planning demand forecast, used for the assessments in the IRRP. This was then converted to a coincident forecast using coincidence factors from the base year (2018). The contribution of conservation and DG to the planning demand forecast is discussed in the following sections.

Figure 5.3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the Southern Huron-Perth sub-region



5.4 Contribution of Conservation to the Forecast

Conservation is a clean and cost effective resource for helping to meet Ontario's electricity needs and has been an integral part of ensuring a reliable and sustainable electricity system in provincial and regional planning. Conservation is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

The following section describes the conservation assumptions included in the forecast. These include savings due to codes and standards, and IESO-delivered conservation programs in 2019 and 2020.[2]

The estimates of demand reduction due to the codes and standards are based on the expected improvement in the codes for new and renovated buildings and for specified categories of consumers, i.e. residential, commercial and industrial, through the regulation of minimum efficiency standards for equipment.

The IESO centrally delivers programs on a province wide basis to serve business and low-income customers, as well as Indigenous communities. Save on Energy programs will result in new savings, reducing energy and peak demand in the sub-region. The forecast included savings achieved through the wind-down of 2015-2020 Conservation First Framework and the 2019-2020 Interim Framework. While these programs are not targeted to a given area, it is assumed that a portion of participation will occur in the sub-region. Savings associated to large transmission-connected industrial loads are highly dependent on actions by the individual customers.

Zonal average CDM savings for industrial loads amalgamate savings across a diverse range of industries. As such, the zonal average may not be completely representative of industrial savings on a more localized scale, such as within Southern Huron-Perth which may not align with that industrial loads mixture. Thus, the conservation savings for large industrial customers were based on known conservation initiatives being undertaken by these customers rather than estimated based on the zonal average.

Figure 5.4 shows the yearly estimate of the reduction to the demand forecast due to conservation for each of the residential, commercial and industrial consumers. As shown, conservation in the residential sector accounts for the largest contribution. Additional details are provided in Appendix A.

[2] Includes savings achieved through the wind-down of 2015-2020 Conservation First Framework and the 2019-2020 Interim Framework.

Figure 5.4 | Reduction to Demand Forecast due to Conservation by Sector (2019-2020 CDM Framework, 2015-2020 Conservation First Framework and Codes and Standards)

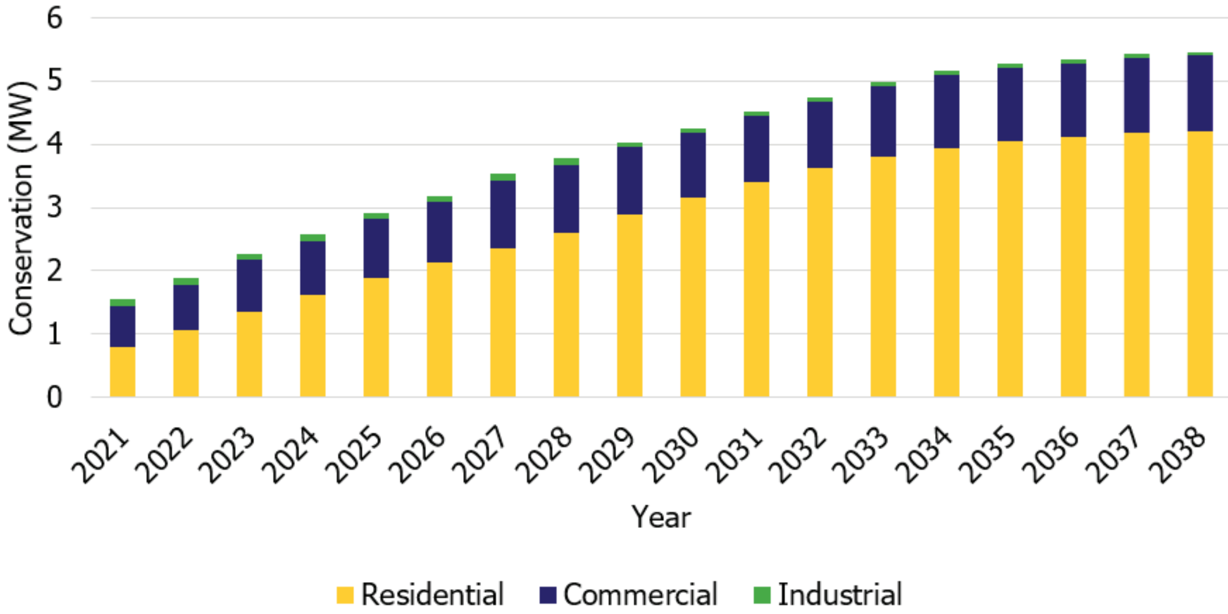
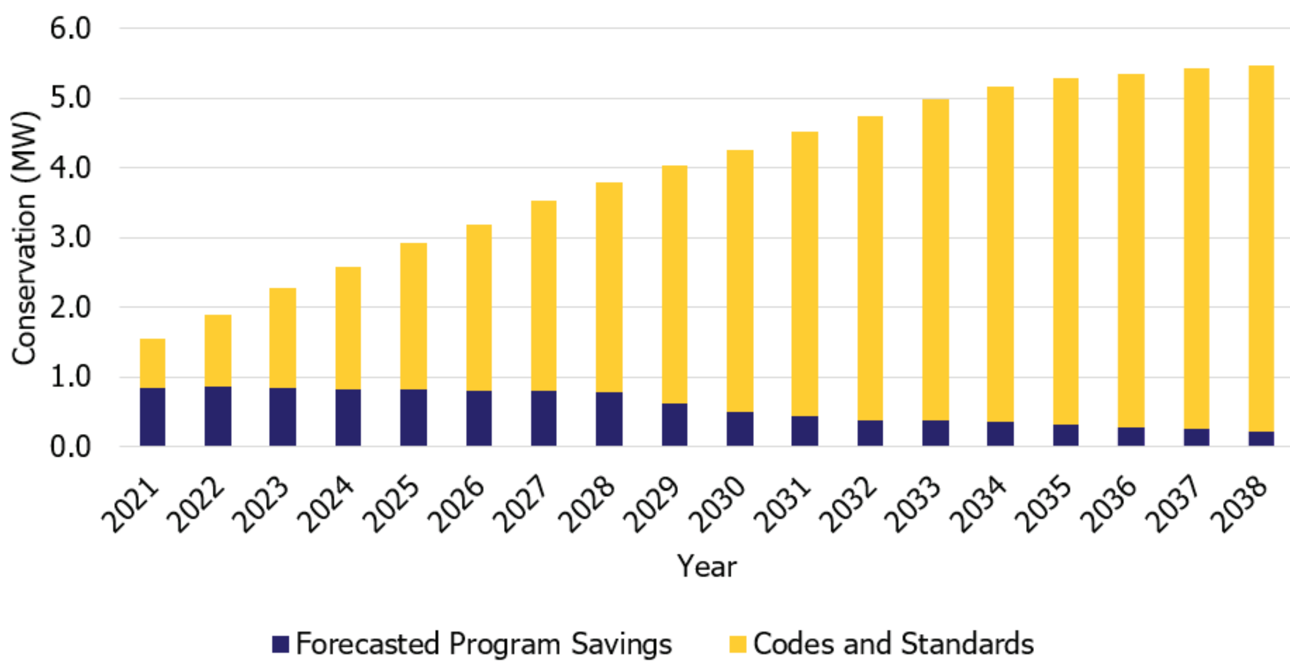


Figure 5.5 shows the yearly estimate of the reduction to the demand forecast due to conservation broken down by regulations and programs. As shown, codes and standards account for the largest contribution to conversation savings in this sub-region. The savings associated with the conservation programs considered in the forecast peaked in 2019-2020 – the target years for the Interim Framework – after which, savings begin to diminish as the conservation measures approach their effective useful life.

Figure 5.5 | Reduction to Demand Forecast due to Conservation by Program



On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework starting in January 2021. As this directive was received after the Southern Huron-Perth sub-region's load forecast was finalized its impact is not included in the forecast nor the above figure. However, it was factored into the conservation calculations during the options analysis in Section 7.

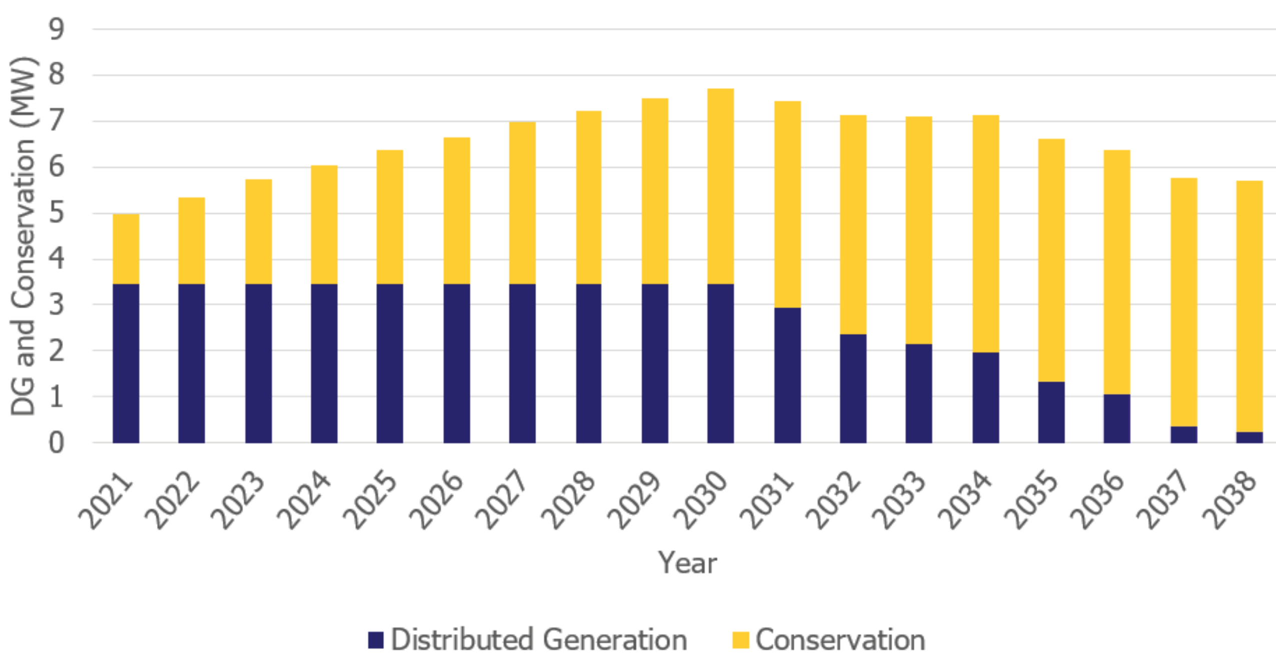
5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Southern Huron-Perth sub-region is also forecast to offset peak-demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's past FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted DG in the region.

Figure 5.6 shows the combined impact of the conservation and DG on reducing the demand forecast. In the long term, as the DG contribution diminishes due to contract expiry, conservation further contributes to reducing the demand and as a result the combined impact remains relatively constant.

Figure 5.6 | Reduction to Demand Forecast due to DG and Conservation



Note that any facilities without a contract are not currently included in the DG forecast.

5.6 Demand Forecast Scenarios

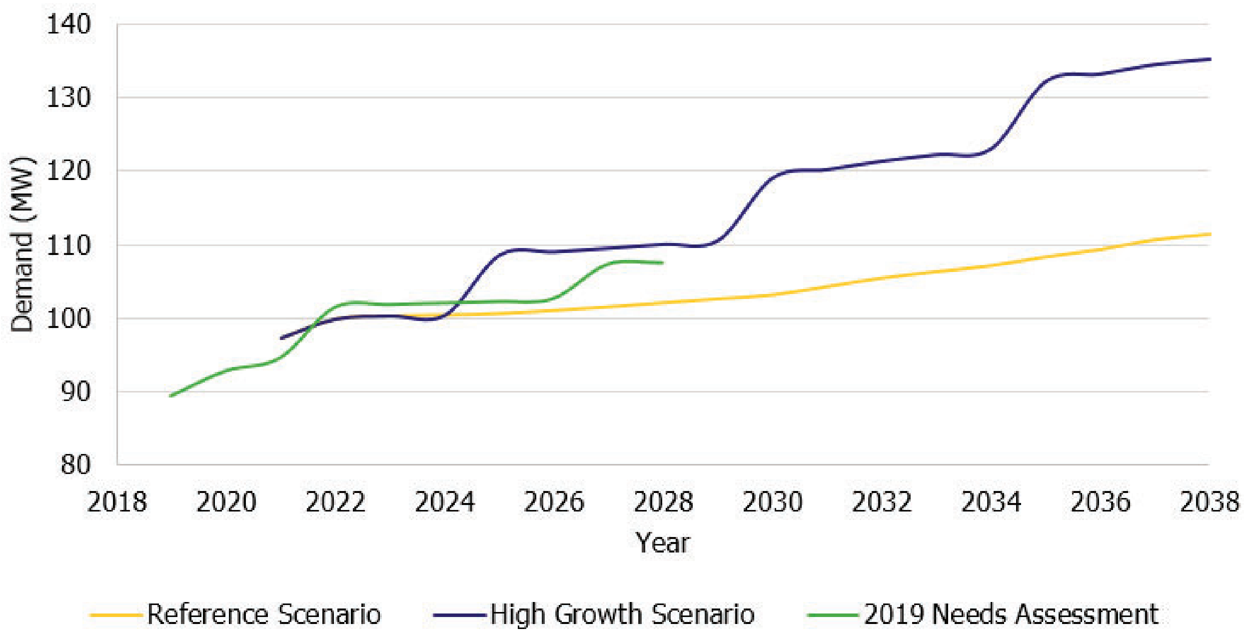
During the Needs Assessment, a significant industrial load project was expected in the sub-region, resulting in anticipated supply capacity needs. When the forecast was refined within the IRRP process, that industrial load project was deferred for at least five years, but with no firm target date. As well, subsequent updates received from stakeholders and communities have indicated there may be unforeseen impacts to the sub-region's demand as the COVID-19 pandemic has changed the way many people live and work.

In order to conduct a comprehensive assessment to identify solutions to address a supply capacity need, if/when the load growth materializes, two forecast scenarios were created:

- Reference Scenario: Following the process described in Section 5.1; and
- High Growth Scenario: The Reference Scenario, with additional 8 MW blocks of industrial growth every five years, starting in 2025.
- The intent of this approach is to identify actions required to address the reference scenario needs, and establish a plan to address the High Growth Scenario needs should they materialize, including if there are near-term actions required to maintain those long-term options. While the impetus for developing a High Growth Scenario was based on projected industrial load growth, this scenario also serves to understand what may be required if and when further load growth materializes, irrespective of the load growth driver.

The two planning forecast scenarios are shown in Figure 5.7, along with what was previously estimated in the 2019 Greater Bruce/Huron Needs Assessment.

Figure 5.7 | Demand Forecast Scenarios



5.7 Project to Consider for Next Cycle

The industrial load expansion project identified in the Needs Assessment was not accounted for in the Reference load forecast during this IRRP cycle because the in-service date was subsequently deferred and so it did not have a confirmed status or connection point. They were modelled in the High Growth Scenario, to outline actions that would be required to address needs if and when the load growth materialized. The Working Group will continue to monitor the situation and if required, a new IRRP cycle or addendum will be launched.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast (extreme weather, net demand), system capability, the transmitter's identified end-of-life asset replacement plans, and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL 001-4 Standard, the Working Group assessed electricity needs in the near-, medium- and long-term timeframe for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.
- **End-of-life Asset Replacement Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based asset demographics (e.g. equipment age). As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

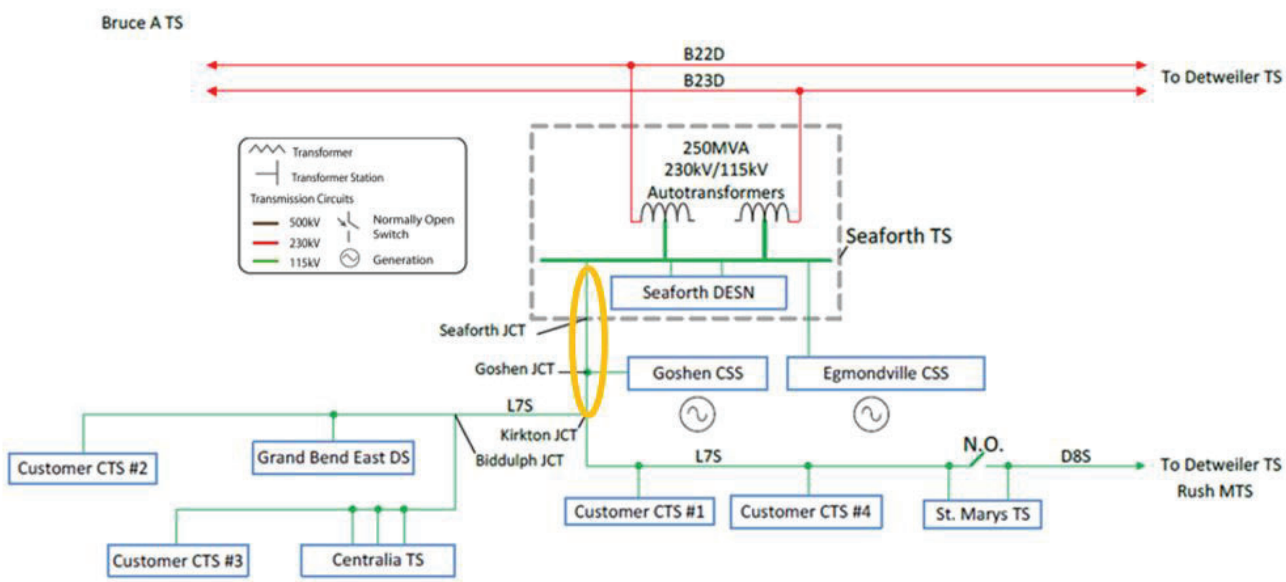
6.2 Needs Identified

The system was analyzed for all in-service conditions and single element contingencies, according to planning standards applicable to this sub-region. Within the Southern Huron-Perth sub-region, no needs were identified under the Reference Scenario, however, long-term supply capacity needs were observed under the High Growth Scenario for the Southern Huron-Perth sub-region. The needs are listed below:

- Possible long-term supply capacity needs under the High Growth Scenario on L7S, the 115 kV circuit from Seaforth TS, following the loss of 115 kV circuit D8S, of up to 11 MW by 2035; and
- Possible long-term supply capacity needs under the High Growth Scenario on L7S following the loss of Seaforth T6 with a prior outage on D8S, of up to 21 MW by 2030.

These supply capacity needs are limited by the same section of L7S circuit, as illustrated in Figure 6.1. As such these supply capacity needs overlap and are not cumulative.

Figure 6.1 | Needs Identified for the Southern Huron-Perth sub-region



7 Plan Options and Recommendations

In developing the plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

7.1 Long-term Needs

A potential long-term supply capacity need emerging in 2035, reaching 11 MW by 2038, was identified on L7S under the High Growth Scenario, following the loss of D8S. Under outage conditions to D8S, the supply need emerging in 2030, reaching 21 MW by 2038, was identified on L7S under the High Growth Scenario, following the loss of Seaforth T6.

The following sections outline the three main options considered to alleviate the potential supply capacity need:

- Load Transfers;
- Conservation and Demand Management; and
- L7S circuit upgrade.

Further details are provided in Appendix B.

Load Transfer

There is the ability to transfer up to 4.4 MW of load from Centralia TS to Seaforth TS, which is upstream of the limiting L7S supply circuit. This would cost approximately $6-12M for distribution buildout. While this would not alleviate the entire supply capacity need, it would defer the High Growth Scenario need until 2035 and could be achieved in a short period of time, i.e. within the year.

Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. The IESO is mandated to centrally deliver province-wide conservation and demand management programs for Ontario that target businesses, select residential customers and First Nations communities. The IESO offers incentives and rebates to electricity customers through a suite of Save on Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs.

Conservation savings that are expected to be achieved through codes and standards and IESO programs delivered in 2019 and 2020, have already been included in the planning forecast scenarios as described in Section Contribution of Conservation to the Forecast5.4.

Since the reference forecast for this IRRP was developed, new energy efficiency programs have been planned beyond 2020 by both federal and Ontario agencies, including the new 2021-2024 CDM Framework. The IESO's new 2021-2024 CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensure energy efficiency can continue to play a role in meeting the sub-region's needs.

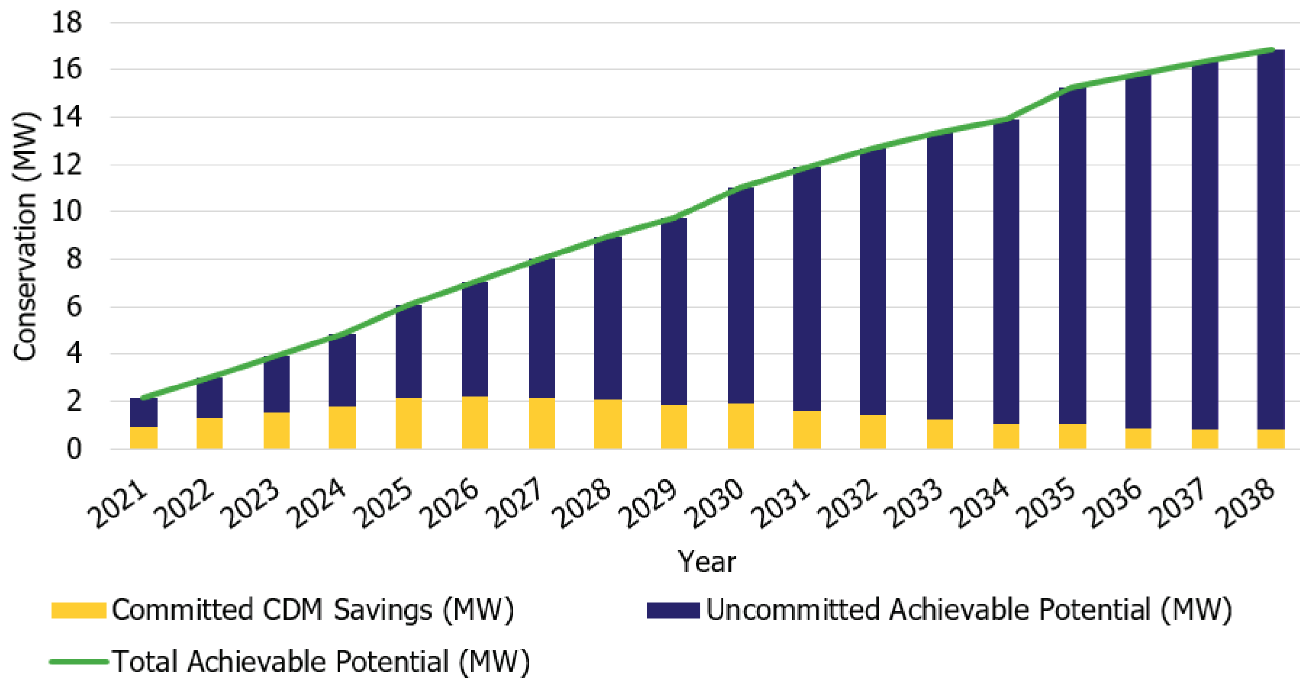
The delivery of the new CDM framework and new federal programs will result in planned reductions in net demand in the region beyond what was included in the forecast. These programs are expected to deliver 0.6 MW of planned savings under the High Growth Scenario by 2038, the end of the study period.[3]

Beyond the forecasted savings expected from the 2021-2024 CDM Framework and new federal programs, there is the potential for further demand reductions from conservation activities. In 2019, the IESO completed an integrated electricity and natural gas conservation Achievable Potential Study in partnership with the Ontario Energy Board. The 2019 Achievable Potential Study identified significant and sustained potential for conservation across all customer sectors throughout the study period. The study results were used to estimate uncommitted conservation opportunities within the Southern Huron-Perth sub-region that are cost effective from the system perspective (i.e., whether the incentive costs are outweighed by the benefits to the electricity system) and not already committed to be delivered under the 2021-2024 CDM Framework and federal programs. Some value is attributed to non-energy benefits, such as customer comfort or improved business productivity.

Based on the demand forecasted under the High Growth Scenario for this region, the total expected achievable potential for conservation savings that is cost effective to the system is 16.7 MW by 2038, as illustrated in Figure 7.1. An estimated 0.6 MW of this potential is expected to be achieved through the 2021-2024 CDM Framework and federal programs. Thus, there is 16.1 MW of uncommitted potential by 2038 under the High Growth Scenario. Implementing both committed and uncommitted savings would defer the need until 2035, for an estimated program cost of $26M, net present value. Although the cost is $26M, for the purpose of this non-wires options assessment a cost of $0 was assumed because these conservation savings are cost-effective to the system, meaning that there is a net benefit when comparing the program investment (cost) against the provincial average avoided costs of providing electricity (benefit).

[3] Similar to the forecasted conservation savings described in Section 5.5, savings expected under this program peak during the target program years, reaching up to 2.2 MW.

Figure 7.1 | CDM Savings Potential under the High Growth Scenario



Note, unlike the savings assumed in the forecast in Section 5.5, this does include potential CDM savings for the forecast industrial loads. Since the zonal average may not be completely representative of industrial savings on a more localized scale, conversations with the new industrial load customers may be required to better understand planned CDM activities. Excluding the savings associated to the new industrial loads,[4] the total achievable potential is 14.8 MW, approximately 14 MW of which is uncommitted.

The Local Initiatives Program (LIP) under the 2021-2024 CDM Framework can target CDM programs to regional and/or local areas to address local supply issues, in addition to, provincial supply issues. The IESO should explore options to target cost effective uncommitted savings to this area using the LIP and other mechanisms.

There are other potential benefits to non-wires investments, such as customer cost savings and reducing GHG emissions. As some of these other objectives may align with municipal energy plans in the sub-region, this may be useful input for identifying the potential for projects and strategies at the local level, while identifying where electrical system benefits and infrastructure deferral value may also exist.

[4] Note, the forecasts for existing transmission-connected industrial customers are calculated based on known CDM activities specific to those facilities, rather than using the zonal averages. Refer to Appendix A.5 for further details.

Transmission Upgrade

The final option considered was upgrading the L7S circuit. While reconductoring would only be required for the limiting section of L7S (between Seaforth TS and Kirkton JCT), this would require installation of new poles along the whole section. While this would provide 50 MW of capacity, more than meeting the supply need identified, it would take 4-5 years, and would cost $10-15M.

Recommendation

While the first two options cannot fully mitigate the High Growth Scenario needs individually, in combination, load transfers and CDM can address the identified need for a total cost of $6-12M and together represent the most cost-effective option. If CDM measures change, this combined option would still provide sufficient lead time to trigger an L7S upgrade, as required. When load levels are within approximately 4 MW of the sub-region's supply capacity, projected to occur within the next 5 years based on the Reference scenario, CDM programs can be pursued and load transfers can be implemented to bridge any potential gap.

Since the appropriate solution for this need is highly dependent on future electricity demand growth, namely the timing and magnitude of the projected industrial load described in Section 5, it is recommended to continue monitoring the situation and devise an appropriate solution when any new demand growth and associated future developments are sufficiently certain.

There may be opportunities for the Working Group to work with communities and local utilities to manage future electricity demand through the development of community-based solutions under the IESO's new CDM Framework, the Indigenous Community Energy Plan Program, or other mechanisms or opportunities that may evolve between planning cycles.

The IESO will monitor the situation and explore long-term solutions with the Working Group and communities, as appropriate, if the need can no longer be addressed without impacting reliability.

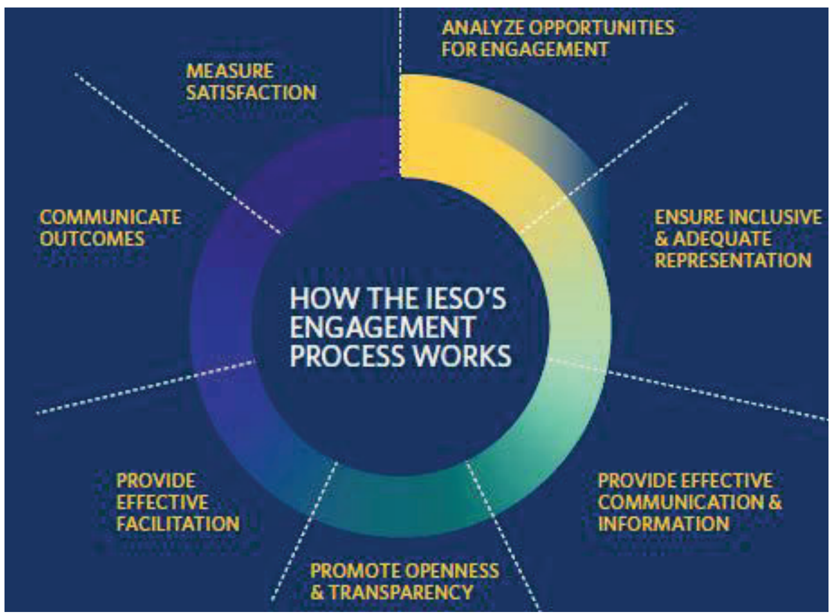
8 Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Southern Huron-Perth IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8.1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Southern Huron-Perth

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Targeted discussions to help inform the engagement approach for the planning cycle;
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Face-to-face meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region.

An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft Greater Bruce/Huron Scoping Assessment Report before it was finalized. Community feedback was received on increased expected economic development being driven by high growth in nearby urban centers such as the City of London that is pushing into areas such as Lucan-Biddulph and West Perth, as well as increased growth in agricultural, residential and industrial developments.

Following a written comment window, the final Scoping Assessment Outcome Report was published in September 2019 that identified the need for a coordinated planning approach done through an IRRP for the Southern Huron-Perth sub-region.

Following these initial discussions and finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the Greater Bruce/Huron region to ensure that all interested parties were made aware of this opportunity for input. Two public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. Both webinars received strong participation with cross-representation of stakeholders and community representatives attending the webinar, and submitting written feedback during a 21-day comment period.

The two stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work
2. The defined electricity needs for the sub-region, options evaluation and draft IRRP recommendations

All interested parties were kept informed throughout this engagement initiative via email to Greater Bruce/Huron region subscribers, municipalities and communities as well as the members of the Southwest Regional Electricity Network.

Based on the discussions both through the Southern Huron-Perth IRRP engagement initiative and broader network dialogue, it is clear that there is broad interest in several Southwestern Ontario communities to further discuss the potential for solutions that incorporate non-wires alternatives. The long-term nature of the Southern Huron-Perth sub-region's potential future electricity needs presents a valuable opportunity for communities to mobilize projects and initiatives to meet local growth targets and energy priorities. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Southern Huron-Perth IRRP engagement webpage.

8.4 Bringing Communities to the Table

The IESO held meetings with communities to seek input on their planning and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Southern Huron-Perth electricity planning sub-region or that may have interests in the sub-region throughout the development of the plan. This includes the communities of Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Chippewas of the Thames, Nawash First Nation, Saugeen First Nation, Historic Saugeen Métis, MNO Great Lakes Métis Council, Six Nations of the Grand River and Haudenosaunee Chiefs Confederacy Council. Further, the IESO endeavoured to identify opportunities for energy projects and initiatives in Indigenous Community Energy Plans for consideration in the long-term electricity planning for the Southern Huron-Perth sub-region. The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9 Conclusion

This report documents an IRRP that has been developed for the Southern Huron-Perth sub-region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. While no needs have been identified under the Reference Scenario, the IRRP lays out actions to monitor, defer, and address long-term needs projected under the High Growth Scenario.

To support the development of the plan, this IRRP includes recommendations with respect to monitoring load growth and efficiency achievements, such as through local initiatives and the Indigenous Community Energy Plan Program. Responsibility for these actions has been assigned to the appropriate members of the Working Group.

The Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Appendix A. Methodology and Assumptions for Demand Forecast

The sections that follow describe the IESO’s methodology to adjust the forecast for extreme weather, LDC methodologies to forecast demand in their respective service area, and the energy efficiency assumptions used to modify the demand based on expected energy efficiency savings. Table A.3 and Table A.4 show the final non-coincident and coincident extreme demand forecast, respectively, per station used for the Reference Scenario assessments. Table A.5 shows the final coincident extreme demand forecast per station used for the High Growth Scenario assessments. The coincident load forecast includes the estimated reduction due to CDM plus DG with the values shown in Table A.6. Table A.7 also shows the gross demand forecast per station as provided by LDCs.

A.1 Method for Accounting for Weather Impact on Demand

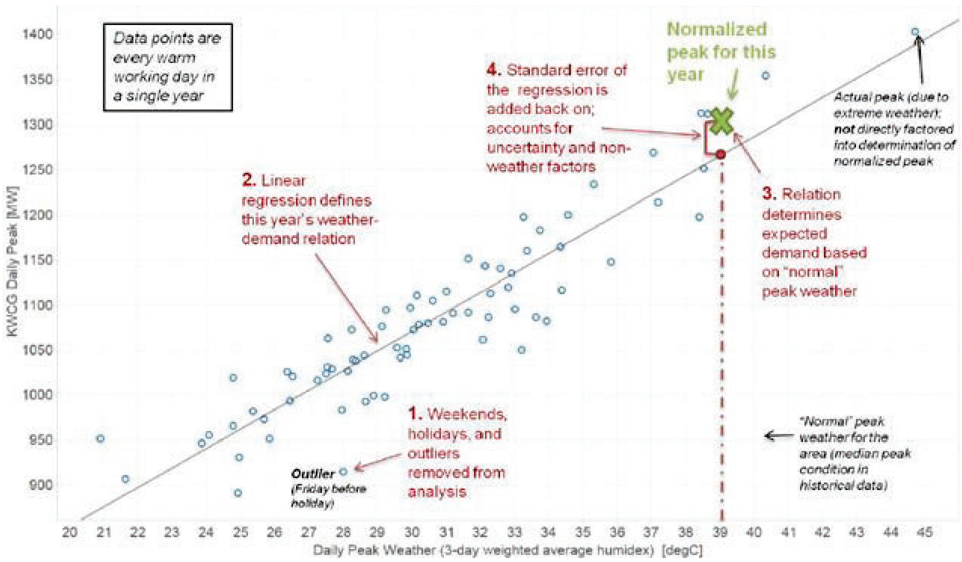
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (in this case 2018). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure A.1.

The 2018 median weather peak on a station and LDC load basis was provided to each LDC. This data was used as a reference stating point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves) are generally when the electricity system infrastructure is most stressed.

Figure A.1 | Method for Determining the Weather-Normalized Peak



A.2 Hydro One Forecast Methodology

Hydro One Distribution provides service across Ontario, including the to counties and townships within Southern Huron-Perth. Three step-down stations supply the distribution-connected customers in the area from the transmission system as follows:

- 115/27.6 kV Centralia TS supplied by 115 kV circuit L7S
- 115/27.6 kV Grand Bend East DS supplied by 115 kV circuit L7S
- 115/27.6 kV St. Marys TS supplied by 115 kV circuits L7S and D8S

There are about 1.4 million Hydro One Distribution retail customers directly connected to Hydro One's distribution system, of which Southern Huron-Perth represents about 8.7% of Hydro One's total electrical load. Hydro One Distribution's customer base within Southern Huron-Perth is comprised of primarily residential (68%) and commercial loads (25%), with some industrial loads (7%). There are two embedded LDCs connected to Hydro One's distribution system within Southern Huron-Perth.

A.2.1 Factors that Affect Electricity Demand

In the Southern Huron-Perth sub-region overall, the agricultural sector and population growth are the main factors of electrical demand growth, impacting the organic residential and commercial growth to support the economic development. The growth is expected to continue to occur around the developed areas in the sub-region. Summer peaks are also impacted by seasonal campground and trailer park loads. There is also an industrial manufacturing load, which may expand over the next few years, which has been accounted for in the High Growth Scenario.

A.2.2 Forecast Methodology and Assumptions

The methodology used was a combination of econometric and end-use forecasting models. These models measured growth from a predetermined baseline demand and took into account the effect of CDM. The following tables outline the growth rate and housing start assumptions used as inputs to the model to account for both provincial and local information.

Table A.1 | Growth Rates for Ontario's GDP (%)

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Growth rate	2.8	2.2	1.7	1.7	1.9	2.0	2.0	2.0	2.0	2.0

Table A.2 | Ontario's Housing Starts (in thousands)

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Housing Starts	9.1	78.4	72.1	70.4	71.7	71.1	71.0	68.7	68.9	68.3

A.3 Festival Hydro Forecast Methodology

Festival Hydro owns and operates the electricity distribution system in its licensed service areas of Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth and Zurich, providing power to 20,000 people.

The stations of concern for this IRRP are the following:

- 115/27.6 kV Grand Bend East DS supplied by 115 kV circuit L7S
- 115/27.6 kV St. Marys TS supplied by 115 kV circuits L7S and D8S

These stations represent 15-20% of Festival Hydro's total electrical load. Festival Hydro's customer base within Southern Huron-Perth is comprised of primarily residential (21%) and industrial loads (56%), along with commercial loads (18%) and mixed commercial/industrial use loads (5%). These loads are supplied through the Hydro One transmission system at primary voltages of 115 kV. Electricity is then distributed through Festival Hydro's service area by two transformer stations within Southern Huron-Perth.

A.3.1 Factors that Affect Electricity Demand

The main variable affecting electricity demand within Festival Hydro's service territory within Southern Huron-Perth is related to population growth and economic development, typically attributed to residential service upgrades and new in-fill development. There is little to no residential development or commercial/industrial load growth is known at this time.

A.3.2 Forecast Methodology and Assumptions

Festival Hydro's load forecast was based on 5-year average plus 0.5% growth each year starting in 2019, following the trend of the last 5 years.

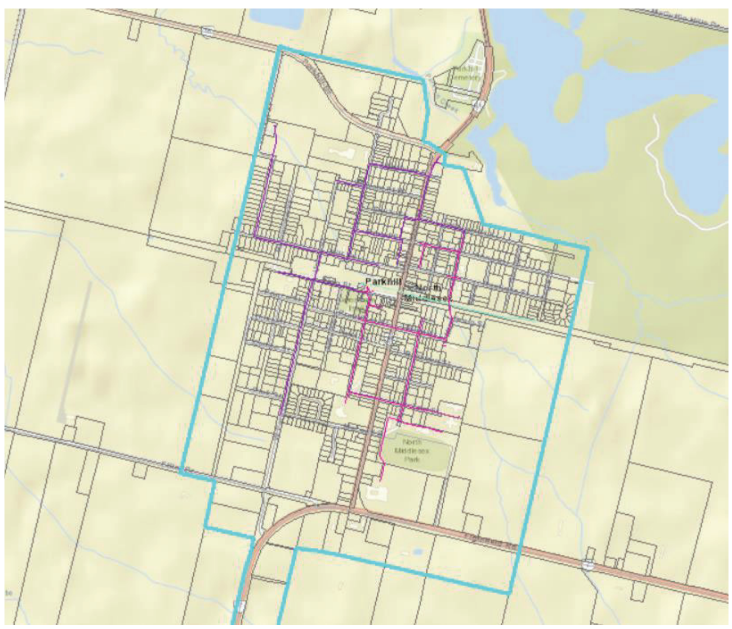
There is also small distribution-connected battery storage facility within Festival Hydro's Southern Huron-Perth service area. For the purposes of this IRRP forecast, this was not relied on to provide any capacity relief because of uncertainties in their behavior at the time of peak demand as it is a non-contracted behind-the-meter facility.

A.4 Entegrus Powerlines Inc. Forecast Methodology

Entegrus is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity and carry on the business of an electricity distributor within its licensed service area. Entegrus owns, operates and manages the assets associated with the distribution of electrical power to approximately 59,000 customers in 17 Southwestern Ontario communities. Entegrus is owned by the Municipality of Chatham-Kent, the City of St. Thomas, and Corix utilities, and is made up of four divisions, including Entegrus Powerlines Inc.

Entegrus provides safe, sustainable and reliable power to Entegrus customers in Blenheim, Bothwell, Chatham (including a portion of the Township of Raleigh known as the "Bloomfield Business Park"), Dresden, Dutton, Erieau, Merlin, Mount Brydges, Newbury, Parkhill, Ridgetown, St. Thomas, Strathroy, Thamesville, Tilbury, Wallaceburg and Wheatley. For the Southern Huron Perth sub-region, the only area served by Entegrus in this region is the town of Parkhill. Entegrus serves approximately 774 customers within this town. This town represents the furthest North community served by Entegrus. The image below represents the Parkhill Entegrus service boundaries. Entegrus' customer base within Southern Huron-Perth is comprised of primarily residential (87%) and commercial loads (13%), supplied through the Hydro One transmission system at primary voltages of 115 kV. Electricity is then distributed through Entegrus' service area by one transformer station within Southern Huron-Perth.

Figure A.2 | Entegrus' Licensed Utility Service Area within Southern Huron-Perth – Parkhill



A.4.1 Factors that Affect Electricity Demand

Parkhill has not seen a lot of growth, nor does the town have any pending connection or generation requests at this time. Projected growth is based on organic

Note, the type of forecasts provided varies based on region and amount of information Entegrus knows at the time of the forecast generation. For example, other areas served by Entegrus with known development, municipal growths plans, and large spot load connections will be incorporated into the forecast. Parkhill historically has been very stable with little growth.

A.4.2 Forecast Methodology and Assumptions

The historical peaks generated in the load forecast template are measured from the Entegrus demarcation wholesale meter and occurred under normal operating conditions. The historical peaks are the metered values for summer and winter. The forecast provided is the net load, i.e., gross peak load minus any existing distributed generation. The town of Parkhill has little generation offsetting the peak. The town is only fed from one supply, so there is no ability for Entegrus to consider load transfers when recording peak data. The town is summer peaking, but the differential between winter and summer month peaks are minor, approximately 300 kW. The town of Parkhill's net load summer peak represents approximately 1% of the entire Entegrus aggregated system peak. The load forecast for Parkhill is primarily based off linear regression (historical net load trend).

A.5 Conservation Assumptions in Demand Forecast

Conservation measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Conservation Programs. The assumptions used for the Southern Huron-Perth IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2019 Annual Planning Outlook, which was the latest provincial planning product when this IRRP was developed, the savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from provincial level to the Southwest transmission zone and then allocated to Southern Huron-Perth sub-region. This appendix describes the process and methodology used to estimate energy efficiency savings for the Southern Huron-Perth sub-region and provides more detail on how the savings for the two categories were developed.

A.5.1 Estimate Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Southwest zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region.

Consistent with the gross demand forecast, 2018 was used as the base year. New peak demand savings from codes and standards were estimated from 2019 to 2038. The residential annual peak reduction percentages of each year were applied to the forecast residential demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2038, the residential sector in the region is expected to see about 7.1% peak demand savings through standards. The same is done for the commercial sector, which will see about 4.9% peak-demand savings through codes and standards by 2038. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. There are no savings from codes and standards considered to be associated with the industrial sector.

A.5.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of conservation programs reduces electricity demand. The impact of existing and committed conservation programs were analyzed, which include the Conservation First Framework wind-down and the Interim Framework. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Southwest zone to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages of program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Southwest transmission zone. They were then applied to sectoral gross peak forecast of each station in the region. By 2020, the residential sector in the region is expected to see about 0.6% peak demand savings through programs, while commercial sector and industrial sector will see about 2.3% and 0.7% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

Note, for all larger industrial customers, this general method is not used to allocate savings to the specific locations. Instead, specific activities undertaken by those facilities are identified based on targeted engagement to include only the savings that are planned.

Since the demand forecast was established in 2019, the subsequent federal and Ontario 2021-2024 programs were not included in the estimated savings. However, when calculating the total achievable potential savings, this is accounted for under the committed savings amount, with costs allocated to the existing program. Accounting for both federal and Ontario programs between 2019-2024, by 2024 the residential sector in the region is expected to see about 0.6% peak demand savings through programs, while commercial sector and industrial sector will see about 6% and 3.2% peak reduction respectively. Similarly, those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

A.5.3 Total Conservation Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector for each forecast category, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

Table A.3 | Reference Summer Non-Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	37	40	41	41	41	41	42	42	42	42	43	43	44	44	44	45	46	46
Grand Bend East DS	22	22	22	22	22	22	22	22	22	22	23	23	23	23	24	24	24	24
St. Marys TS	28	28	28	28	28	29	29	29	29	30	30	30	31	31	31	31	32	32
CTS #4	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
CTS #1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
CTS #3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CTS #2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total	117	120	121	121	121	122	122	123	124	124	125	126	127	128	129	130	132	133

Table A.4 | Reference Summer Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	34	36	37	37	37	37	37	38	38	38	38	39	39	40	40	40	41	42
Grand Bend East DS	16	16	16	16	16	17	17	17	17	17	17	17	17	17	18	18	18	18
St. Marys TS	25	26	26	26	26	26	27	27	27	27	27	28	28	28	29	29	29	30
CTS #4	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
CTS #1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CTS #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total	97	100	100	101	101	102	102	103	103	104	104	105	106	107	108	109	110	111

Table A.5 | High Growth Summer Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	34	36	37	37	40	40	40	40	41	44	44	45	45	46	49	50	51	51
Grand Bend East DS	16	16	16	16	16	16	17	17	17	17	17	17	17	17	18	18	18	18
St. Marys TS	25	26	26	26	31	31	31	31	32	37	37	38	38	38	44	44	44	45
CTS #4	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
CTS #1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CTS #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total	97	100	100	100	109	109	110	110	111	119	120	121	122	123	132	133	135	135

Table A.6 | CDM and DG Contribution (MW) Considered in Reference Coincident Extreme Peak Demand Forecast

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	2.8	3.0	3.2	3.4	3.5	3.7	3.9	4.0	4.2	4.3	4.1	3.8	3.9	3.9	3.9	3.7	3.1	3.1
Grand Bend East DS	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.0	2.1	2.0	2.0	1.5	1.5	1.5	1.5
St. Marys TS	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.3	1.3	1.4	1.3	1.3	1.2	1.2	1.3	1.3	1.2	1.1
CTS #4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5.0	5.3	5.7	6.0	6.4	6.6	7.0	7.2	7.5	7.7	7.4	7.1	7.1	7.1	6.6	6.4	5.8	5.7

Table A.7 | Reference Summer LDC Coincident Gross Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	37	40	41	41	42	42	42	43	43	43	44	44	44	45	45	45	46	46
Grand Bend East DS	21	21	21	21	22	22	22	22	22	22	22	23	23	23	23	23	23	23
St. Marys TS	26	27	27	27	28	28	28	28	29	29	29	29	30	30	30	30	31	31
CTS #4	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
CTS #1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
CTS #3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CTS #2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total	115	118	119	120	121	121	122	123	124	124	125	126	127	127	128	129	129	130

Appendix B. Solution Options to Supply Capacity Need in the High Growth Scenario

Table B.1 | Comparison of Solution Options for High Growth Scenario Needs

Option	Description	Load Supply Capability (MW)	Total Cost	Cost per Additional MW of Supplied Load
1	Transfer load from Centralia TS to Seaforth TS	4.4*	$6-12M	$136-273k
2	Conservation and Demand Management	16.1**	$26M***	$1.62M***-
3	Upgrade limiting section of L7S 115 kV circuit	50	$10-15M	$200-300k

*This is will will require a new feeder position at Seaforth TS, included in the costs.
**Maximum uncommitted CDM potential, net of the 0.9 MW of comitted CDM from forecast and planned provincial and federal CDM programs. This potential would be achieved through new initiatves. Costs are based on historic CDM program costs.
*** Cost for these system cost-effective resources will be recovered through a provincial program.

Appendix C. Development of the Plan

C.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the OEB convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a needs assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a scoping assessment to determine what type of planning is required for a region. A scoping assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused RIP can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure C.1, three levels of electricity system planning are carried out in Ontario:

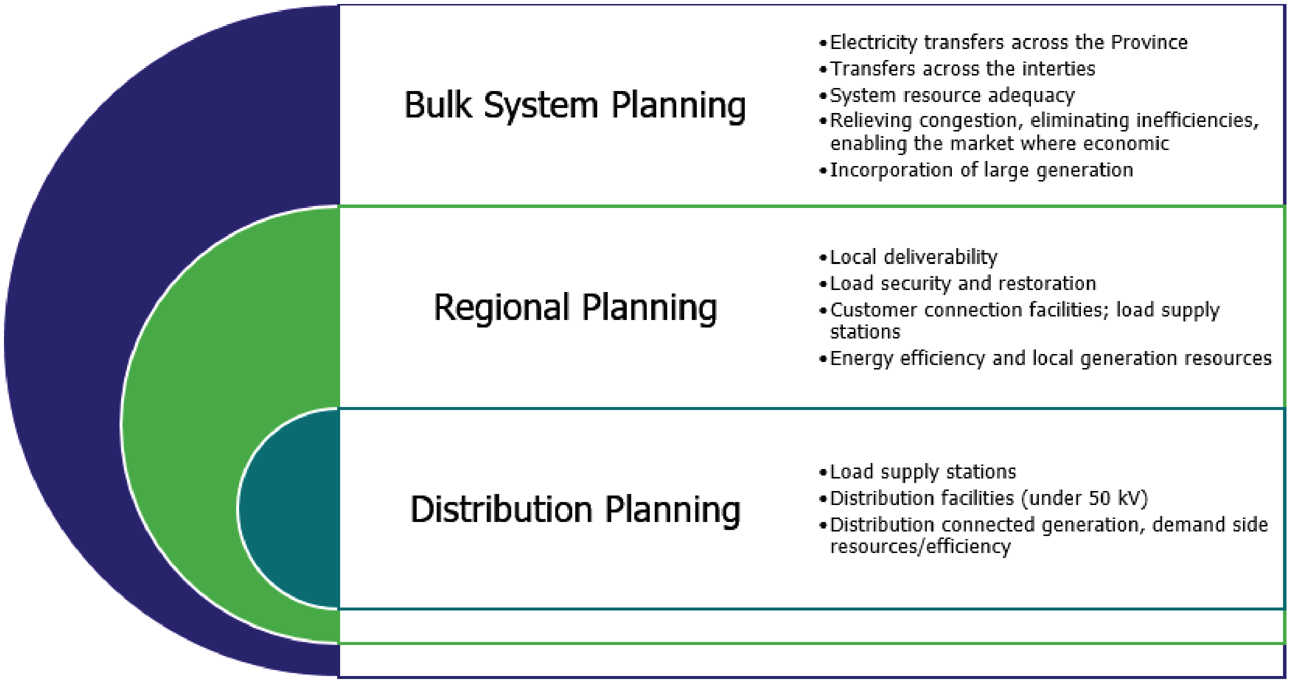
- Bulk system planning;
- Regional system planning; and
- Distribution system planning.

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Figure C.1 | Levels of Electricity System Planning



C.2 IESO's Approach to Regional Planning

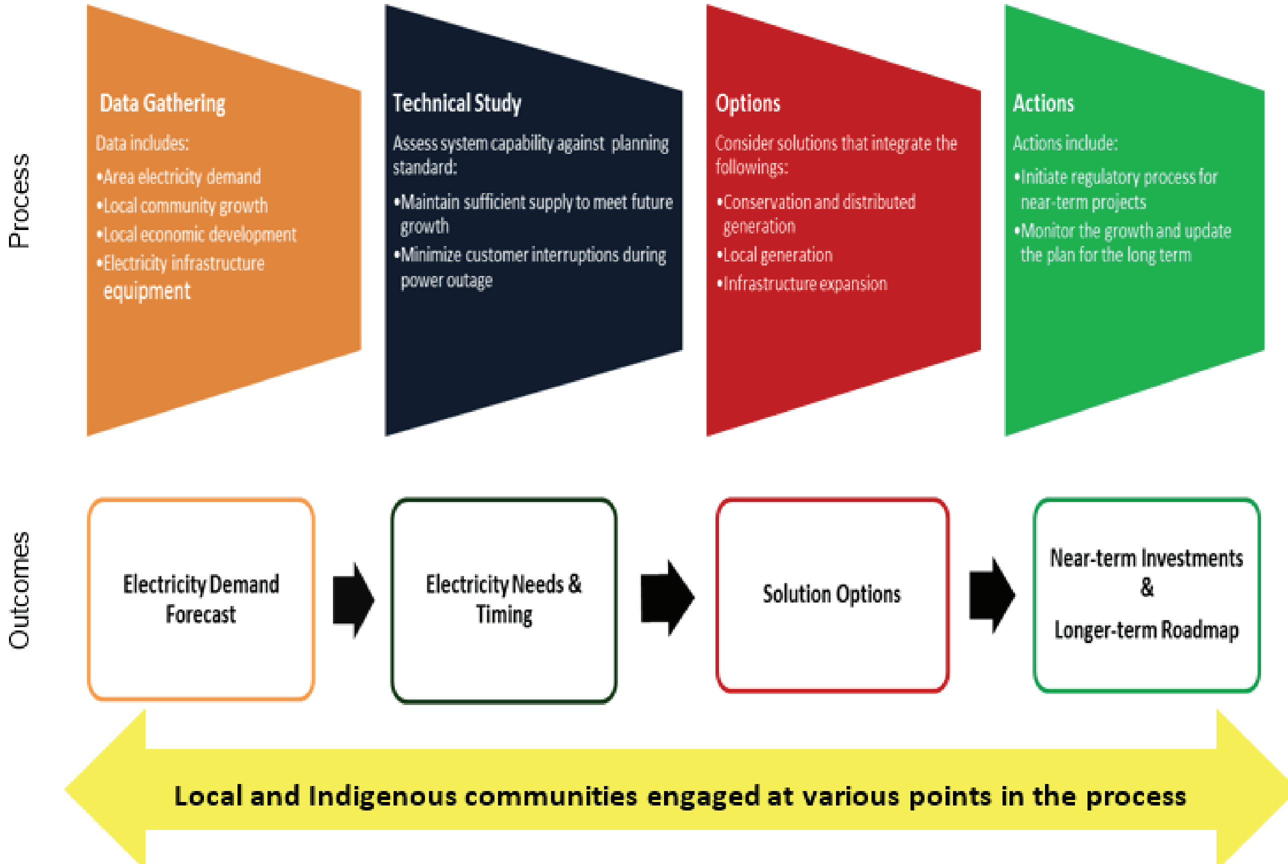
IRRPs assess electricity system needs for a region over a 20-year period, enabling near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

The IRRP describes the Working Group's recommendations for mitigating reliability and cost risks related to end-of-life asset replacement and demand forecast uncertainty associated with large load customers or due to any changes in the existing provincial conservation targets. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

In developing an IRRP, the IESO and the study team follow a process, with a clearly defined series of steps (see Figure C.2). These includes developing electricity demand forecasts; conducting technical studies to determine electricity needs and the timing of these needs; considering potential options; and creating a plan with recommended actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and Indigenous communities who may have an interest in the area.

The IRRP report documents the inputs, findings and recommendations developed through this process, and outlines recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

Figure C.2 | Steps in the IRRP Process



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APPENDIX E. System Capability Assessment for Renewable Energy Generation

This appendix is applicable to distributors that have incurred or expect to incur costs to accommodate and connect renewable generation facilities that are eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the Ontario Energy Board Act, 1998.

A distributor's investments to accommodate and connect REG (including connection assets, expansions and/or renewable enabling improvements) are part of its DSP. This includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the Ontario Energy Board Act, 1998. REG investments can be stand-alone or integrated into a project/program; and are to be categorized for the purposes of section 5.4 in the same way as any other investment.

A distributor should provide information on the capability of its distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity should also be provided.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) Applications from renewable generators over 10 kW for connection in the distributor's service area

b) The number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the IESO and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown must be provided)

c) The capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area

d) Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter)

e) Constraints for an embedded distributor that may result from the connections

ERTH POWER

Renewable Energy Generation (REG) Plan

The following document has been created to examine Renewable Energy Generation within ERTH Power's service territories, identify any constraints limiting new connections and discuss expected investments as a result.

UPDATED:
May, 2024

Contents

Executive Summary

The following document has been created to examine Renewable Energy Generation (REG) within ERTH Power's service territories, identify any constraints limiting new connections and discuss expected investments as a result. ERTH has currently[1] connected **35.992 MW** (35,992kW) of renewable energy generation.

ERTH has REG capacity constraints on various feeders, throughout our service territory including:

- Belmont: <10MW & >10kW
- Thamesford: <10kW (limited capacity, 700kW available under Threshold Allocation HONI# 49,380)
- Clinton F2: <10kW
- Embro: <10kW
- Goderich M3: <10kW (1MW Threshold Capacity Allocation applied for to allow micro) as well

ERTH currently has twelve (12) micro-NET metering projects totalling 105kW, seven (7) large-NET metering projects totalling 1,115kW, and three (3) Load Displacement project totalling 7,647kW in our queue. The province of Ontario is anticipating significant growth in distributed generation over the coming years, however, ERTH Power is unable to quantify the pace and scale of these installations in the short to long term.

ERTH participates in two (2) regional planning groups: the London Area and the Greater Bruce/Huron Area which have both been initiated in Q2 of 2024; we are unable to confirm if any capital investments will be required but are not anticipating any.

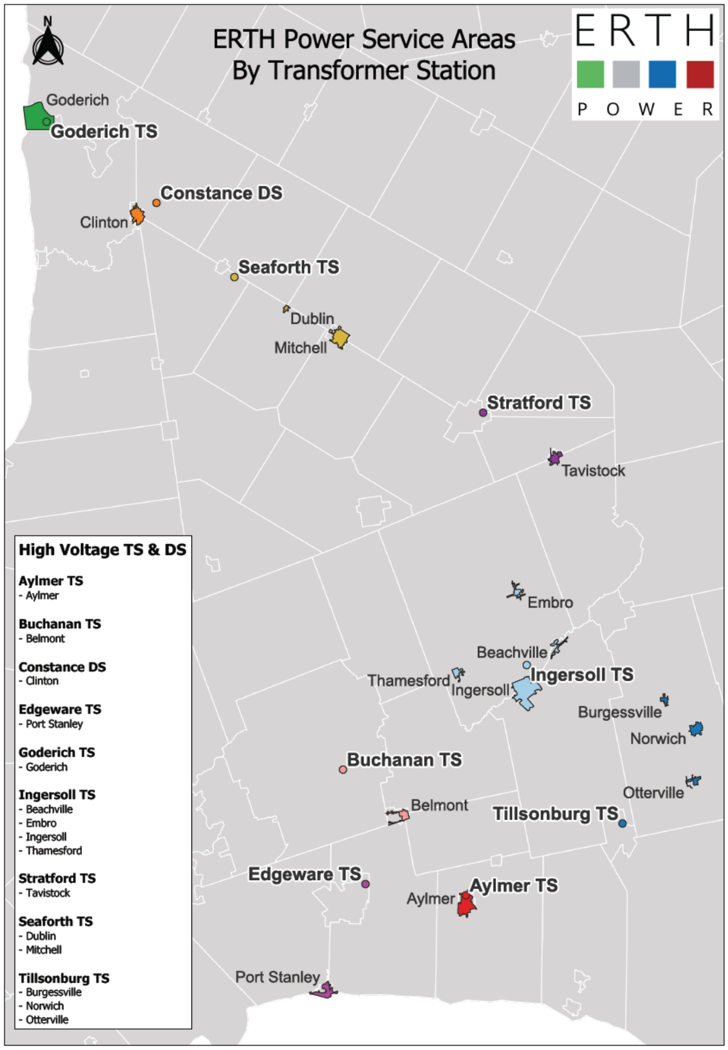
[1] Renewable Energy Connections (REG) updated as of May 2024.

System Overview

The majority of ERTH's fifteen (15) municipalities are embedded and supplied from various Hydro One distribution circuit(s) with the Town of Aylmer and the Town of Goderich having the only TX connected supply points. ERTH is supplied by eight (8) Transmission Stations, one (1) high voltage Distribution Station, and three (3) Distribution Stations owned and operated by Hydro One as detailed below.

Municipality	Hydro One Supply Station	Feeder ID	Supply Voltage (kV)	Connection Level
Aylmer	Aylmer TS	M3	27.6Y/16	**TX**
		M4	27.6Y/16	**TX**
		M5	27.6Y/16	**TX**
Beachville	Ingersoll TS	M44	27.6Y/16	DX
Belmont	Buchanan TS	M21	27.6Y/16	DX
	Belmont DS (via Buchanan M21)	F1	8.32Y/4.8	DX
Burgessville	North Norwich DS (via Tillsonburg M3)	F2	8.32Y/4.8	DX
Clinton	Constance DS	F2	27.6Y/16	DX
		F4	27.6Y/16	DX
Dublin	Dublin DS (supplied by Seaforth TS)	F1 (Seaforth M2)	8.32Y/4.8	DX
Embro	Ingersoll TS	M46	27.6Y/16	DX
Goderich	Goderich TS	M3	27.6Y/16	**TX**
		M4	27.6Y/16	**TX**
		M5	27.6Y/16	**TX**
Ingersoll	Ingersoll TS	M49	27.6Y/16	DX
		M50	27.6Y/16	DX
		M51	27.6Y/16	DX
		M52	27.6Y/16	DX
Mitchell	Seaforth TS	M2	27.6Y/16	DX
Norwich	Tillsonburg TS	M3	27.6Y/16	DX
Otterville	Tillsonburg TS	M1	27.6Y/16	DX
	Otterville DS (via Tillsonburg M1)	F1	8.32Y/4.8	DX
Port Stanley	Edgeware TS	M3	27.6Y/16	DX
Tavistock	Stratford TS	M7	27.6Y/16	DX
Thamesford	Ingersoll TS	M43	27.6Y/16	DS
	Ingersoll TS	M45	27.6Y/16	DS

The figure below shows the location of each municipality relative to the respective Hydro One owned supply station.

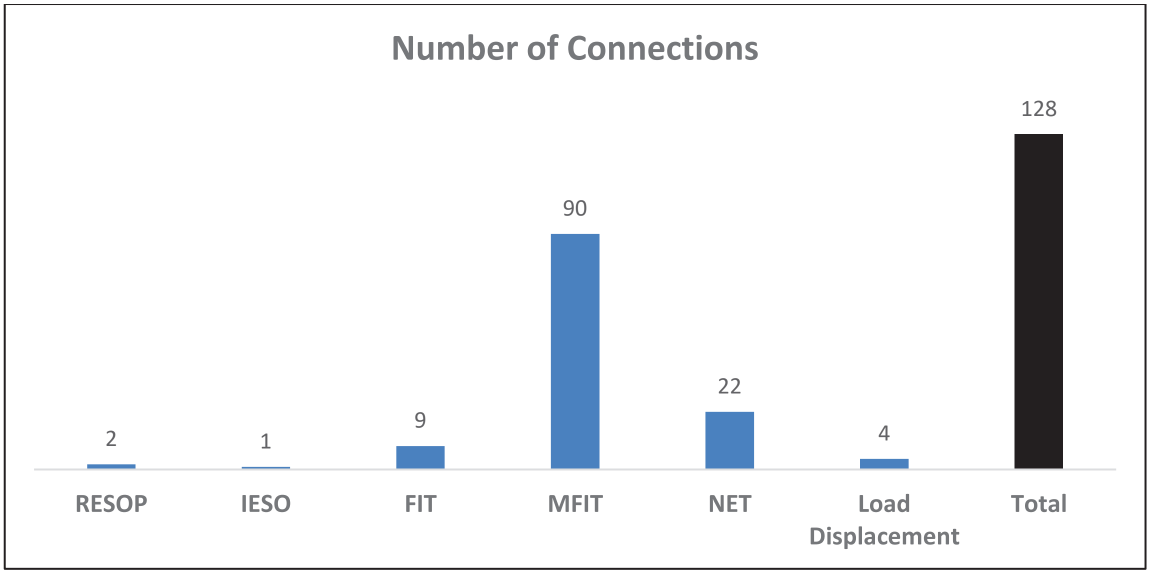


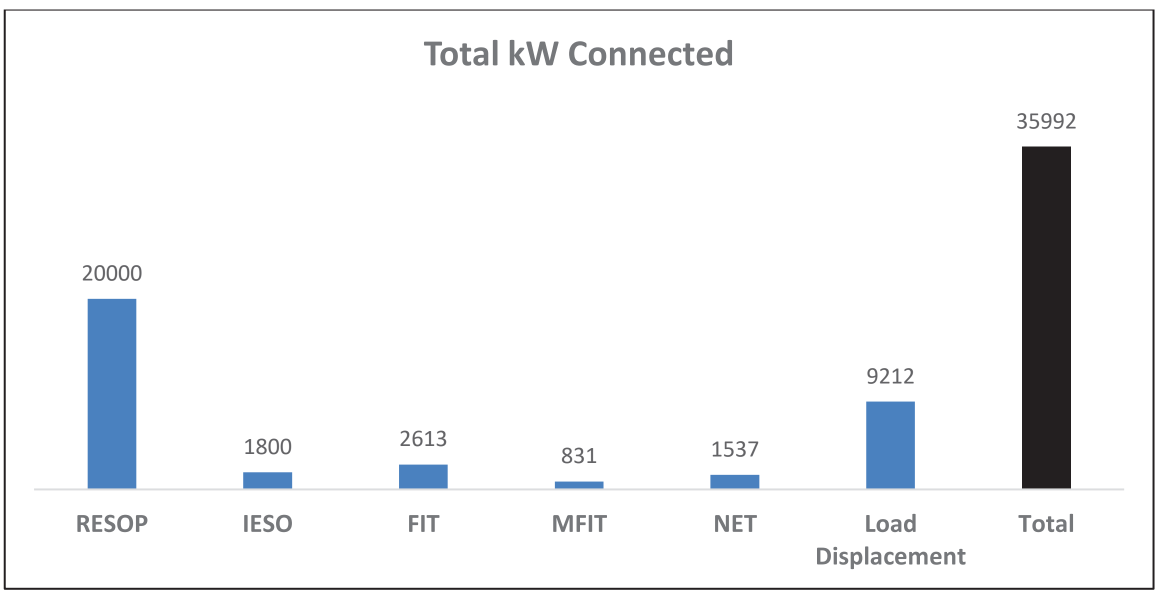
In addition, ERTH owns ten (10) municipal substations, converting voltages from 27.6Y/16kV to 4.19Y/2.4kV.

Municipality	Station ID	# of Feeders
Aylmer	MS1	2
	MS2	4
Beachville	MS1	1
Clinton	MS1	3
Ingersoll	MS1	2
Port Stanley	MS1	1
Tavistock	MS1	2
Goderich	MS2	2
	MS3	2
	MS4	2

REG Connection by Program

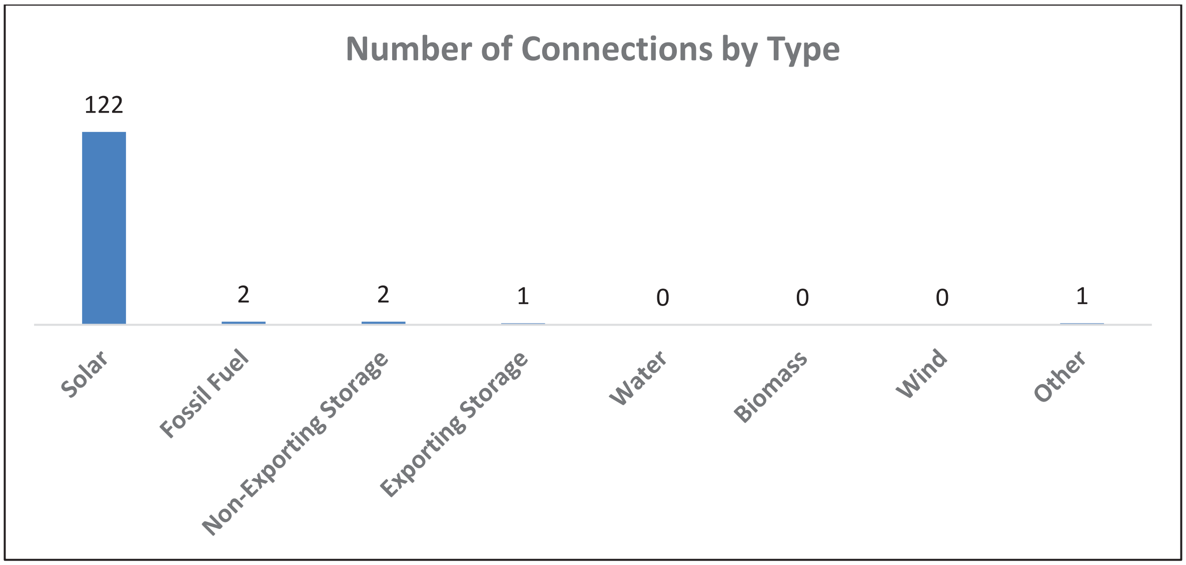
	RESOP	IESO	FIT	MFIT	NET	Load Displacement	Total
Number of Connections	2	1	9	90	22	4	128
Total kW	20000	1800	2613	831	1537	9212	35992

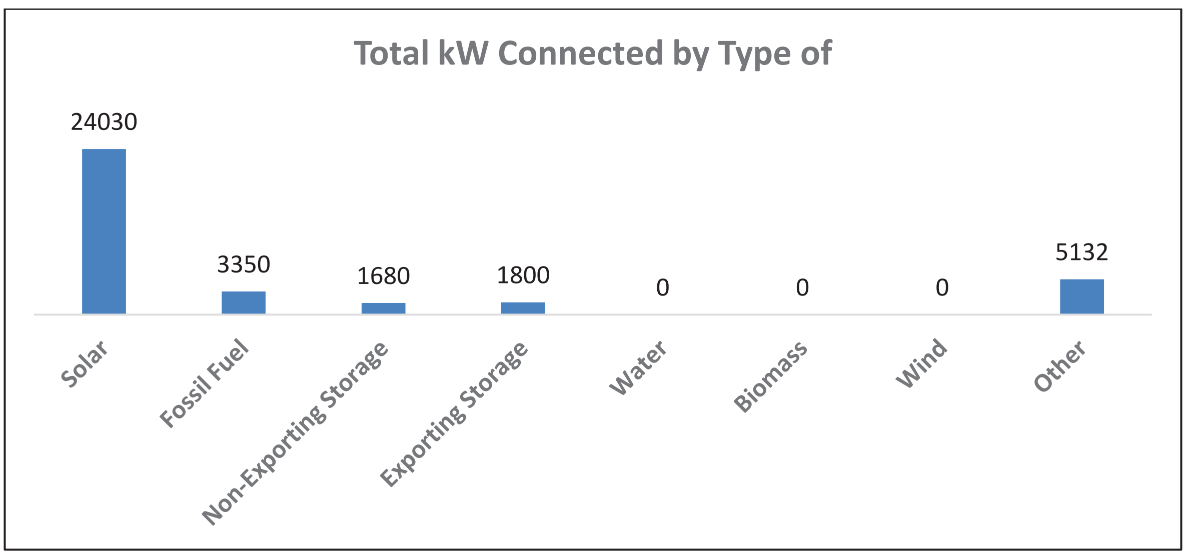




REG Connections by Type

	Solar	Fossil Fuel	Non-Exporting Storage	Exporting Storage	Water	Biomass	Wind	Other
Number of Connections	122	2	2	1	0	0	0	1
Total kW	24030	3350	1680	1800	0	0	0	5132





REG Capacity Considerations (Constraints)

As per the recent DECRP, ERTH Power has posted its capacity constraints publically by feeder on our website located at the following address:

https://www.erthpower.com/sustainability/distributed-energy-resources-ders/der-connection-process-and-forms/

Large, >10 kW Capacity Limitations

Large, >10kW generators are connected through a well structured process that includes a CIA (Connection Impact Assessment) that evaluates capacity and the ability to connect proposed generator at a specific location. As a preliminary capacity check, ERTH utilizes the published Hydro One capacity limitations resulting in the following capacity within our system:

Service Territory	Transformer Station	Feeder	Feeder Limit kW (Max 400A, 200A)	Remaining Generation Capacity (kW)	Hydro One Station and Feeder Capacity Calculator (Exporting only)
Aylmer	Aylmer TS	M3	19,121	15,650	15,000
Aylmer	Aylmer TS	M4	19,121	19,095	15,000
Aylmer	Aylmer TS	M5	19,121	19,121	15,000
Beachville	Ingersoll TS	M44	19,121	19,074	15,640
Belmont	Buchanan TS	M21	19,121	0	Constrained
Burgessville	Norwich North DS (supplied by Tillsonburg TS)	F2 (Tillsonburg M3)	2,882	2,882	2,720
Clinton	Constance DS	F2	19,121	16,094	14,250
Clinton	Constance DS	F4	19,121	19,121	14,250
Dublin	Dublin DS (supplied by Seaforth TS)	F1 (Seaforth M2)	2,882	2,882	2,090
Embro	Ingersoll TS	M46	19,121	7,711	7,590
Goderich	Goderich TS	M3	2,850	1,040	2,835
Goderich	Goderich TS	M4	19,121	19,121	2,835
Goderich	Goderich TS	M5	19,121	2,835	2,835
Ingersoll	Ingersoll TS	M49	19,121	15,650	15,625
Ingersoll	Ingersoll TS	M50	19,121	10,925	15,640
Mitchell	Seaforth TS	M2	19,121	15,750	15,630
Norwich	Tillsonburg TS	M3	19,121	15,775	15,640
Otterville	Tillsonburg TS	M1	19,121	19,048	3,182
Otterville	Otterville DS (supplied by Tillsonburg TS)	F1 (Tillsonburg M1)	19,121	19,091	1,800
Port Stanley	Edgeware TS	M3	19,121	19,111	18,650
Tavistock	Stratford TS	M7	2,882	2,882	2,850
Thamesford	Ingersoll TS	M45	19,121	19,095	10

Micro, <10kW Capacity Limitations

ERTH Power must comply with the Hydro One TIR (Technical Interconnection Requirements) with respect to connection of micro-generation. This includes a requirement to limit the total generation connected to our line section to 7% of the annual line section, peak load; this excludes generators that cannot export power from the customer's site. (7% Rule) As a result, ERTH Power has constraints in certain municipalities as outlined in the table below:

Service Territory	Transformer Station	Feeder	DG % Limit	Allowable Generation 3Ph (kW)	Allowable Generation 1Ph (kW)	Available Generation Red (kW)	Available Generation White (kW)	Available Generation Blue (kW)
Aylmer	Aylmer TS	M3	7%	366	122	119	119	111
Aylmer	Aylmer TS	M4	7%	611	204	201	201	183
Aylmer	Aylmer TS	M5	7%	599	200	200	200	200
Beachville	Ingersoll TS	M44	7%	70	23	4	6	13
Belmont	Buchanan TS	M21	7%	221	74	CONSTRAINED		
Burgessville	Norwich North DS (supplied by Tillsonburg TS)	F2 (Tillsonburg M3)	7%	31	10	10	10	10
Clinton	Constance DS	F2	7%	225	75	CONSTRAINED		
Clinton	Constance DS	F4	7%	214	71	71	71	71
Dublin	Dublin DS (supplied by Seaforth TS)	F1 (Seaforth M2)	7%	31	10	10	10	10
Embro	Ingersoll TS	M46	7%	80	27	CONSTRAINED		
Goderich	Goderich TS	M3	7%	550	183	CONSTRAINED		
Goderich	Goderich TS	M4	7%	1,175	392	392	392	392
Goderich	Goderich TS	M5	7%	593	198	190	188	174
Ingersoll	Ingersoll TS	M49	7%	722	241	241	241	241
Ingersoll	Ingersoll TS	M50	7%	967	322	160	147	138
Mitchell	Seaforth TS	M2	7%	681	227	217	194	197
Norwich	Tillsonburg TS	M3	7%	291	97	84	84	94
Otterville	Tillsonburg TS	M1	7%	39	13	3	13	13
Otterville	Otterville DS (supplied by Tillsonburg TS)	F1 (Tillsonburg M1)	7%	80	27	27	27	27
Port Stanley	Edgeware TS	M3	7%	279	93	87	83	83
Tavistock	Stratford TS	M7	7%	522	174	62	81	35
Thamesford	Ingersoll TS	M45	7%	129	43	10	10	CONSTRAINED

Threshold Capacity Allocation (TA)

ERTH has begun to utilize a relatively new application called the Threshold Allocation (TA) with Hydro One, that allows an embedded distributor to apply for allocation of generation connection capacity on a feeder. Once evaluated and approved by Hydro One, ERTH can connect the following without having Hydro One conduct a formal review of the connection under Section 6.2.1.1(a) of the Distribution System Code (DSC).

(a) *Embedded Generation Facility (including Load Displacement and Net Metered Generation Facilities) with a nameplate rated capacity that does not exceed 250 kW;*

(b) *Storage Facility with a capacity that does not exceed 250 kW; and*

(c) *Micro-Embedded Generation Facility (≤ 10 kW);*

REG Forecast

ERTH currently has twelve (12) micro-NET metering projects totalling 105kW, seven (7) large-NET metering projects totalling 1,115kW, and three (3) Load Displacement project totalling 7,647kW in our queue. These projects are anywhere from an initial customer inquiry to pending construction.

The province of Ontario is anticipating significant growth in distributed generation over the coming years, driven by advances in renewable energy technologies, supportive government policies, and increasing consumer interest in sustainable energy solutions. This growth is expected to see a substantial rise in the installation of distributed energy resources (DERs) at residential, commercial, and industrial sites. That being said, ERTH Power is unable to quantify the pace and scale of these installations in the short to long term.

REG Investment Expectations

ERTH participates in two (2) regional planning groups: the London Area and the Greater Bruce/Huron Area.

The London Area has completed two (2) planning cycles (2015 & 2020) with the latter being completed with the publication of the Regional Infrastructure Plan (RIP) report in August of 202. The next planning cycle for this region has just been initiated in May of 2024; as a result, of the third cycle, just commencing <u>ERTH does not have sufficient information regarding any capital investment requirements; however, none are expected at this time</u>

The Greater Bruce/Huron Area has completed two (2) planning cycles (2016 & 2019) which was completed with a RIP in April 2022. The next planning cycle for this region has just recently commenced in April 2024. As a result, of the third cycle, just commencing <u>ERTH does not have sufficient information regarding any capital investment requirements; however, none are expected at this time.</u>

As outlined in the Capacity Constraint tables above, ERTH will not be able to connect generation on certain feeders. Due to the nature of these constraints, <u>ERTH again does not expect any capital expenditure into the system as a result.</u>

Appendix A: Restricted Feeder List

DER CONNECTION PROCEDURES
RESTRICTED FEEDER LIST

Report Date: January 1, 2024 Next Release: January 1, 2025

Town	Station	Feeder	Voltage (kV)	Restricted
Aylmer	Aylmer TS	34M3	27.6/16	No
	AYL-MS1 (Forest)	AYL-1F1	4.16/2.4	No
	AYL-MS1 (Forest)	AYL-1F2	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F1	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F2	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F3	4.16/2.4	No
	AYL-MS2 (McBrien)	AYL-2F4	4.16/2.4	No
	Aylmer TS	34M4	27.6/16	No
	Aylmer TS	34M5	27.6/16	No
Beachville	Ingersoll TS	38M44	27.6/16	No
	BEA-MS1	BEA-1F1	4.16/2.4	No
Belmont	Buchanan TS	19M21	27.6/16	Yes
	Belmont DS	F1	8.32/4.8	Yes
Burgessville	Tillsonburg TS	20M3	27.6/16	No
	Norwich North DS	F2	8.32/4.8	No
Clinton	Constance DS	F2	27.6/16	No
	CLI-MS1	CLN-1F1	4.16/2.4	No
	CLI-MS1	CLN-1F2	4.16/2.4	No
	CLI-MS1	CLN-1F3	4.16/2.4	No
	Constance DS	F4	27.6/16	No
Dublin	Seaforth TS	61M2	27.6/16	No
	Dublin DS	F1	8.32/4.8	No
Embro	Ingersoll TS	38M46	27.6/16	No
Goderich	Goderich TS	31M3	27.6/16	No
	GDE-MS2	GDE-2F2	4.16/2.4	No
	GDE-MS2	GDE-2F3	4.16/2.4	No
	Goderich TS	31M4	27.6/16	No
	Goderich TS	31M5	27.6/16	No
	GDE-MS3	GDE-3F3	4.16/2.4	No
	GDE-MS3	GDE-3F4	4.16/2.4	No
	GDE-MS4	GDE-4F1	4.16/2.4	No
	GDE-MS4	GDE-4F3	4.16/2.4	No
Ingersoll	Ingersoll TS	38M49	27.6/16	No
	Ingersoll TS	38M50	27.6/16	No
	ING-MS1	ING-1F1	4.16/2.4	No
	ING-MS1	ING-1F2	4.16/2.4	No
	Ingersoll TS	38M51	27.6/16	No
	Ingersoll TS	38M52	27.6/16	No
Mitchell	Seaforth TS	61M2	27.6/16	No
	TX#1517	F1	4.16/2.4	No
Norwich	Tillsonburg TS	20M3	27.6/16	No
Otterville	Tillsonburg TS	20M1	27.6/16	No
	Otterville DS	F1	8.32/4.8	No
Port Stanley	Edgeware TS	27M3	27.6/16	Yes
	PTS-MS1	PTS-1F1	4.16/2.4	Yes
Tavistock	Stratford TS	68M7	27.6/16	No
	TAV-MS1	TAV-1F2	4.16/2.4	No
	TAV-MS1	TAV-1F3	4.16/2.4	No
Thamesford	Ingersoll TS	38M45	27.6/16	No

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APPENDIX F. 2023 ERTH Power Reliability Report

ERTH
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2023
ERTH Power Reliability Report

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1. Definitions

System Average Interruption Duration Index (SAIDI): the minutes of non-momentary electric interruptions, per year, the average customer experienced.

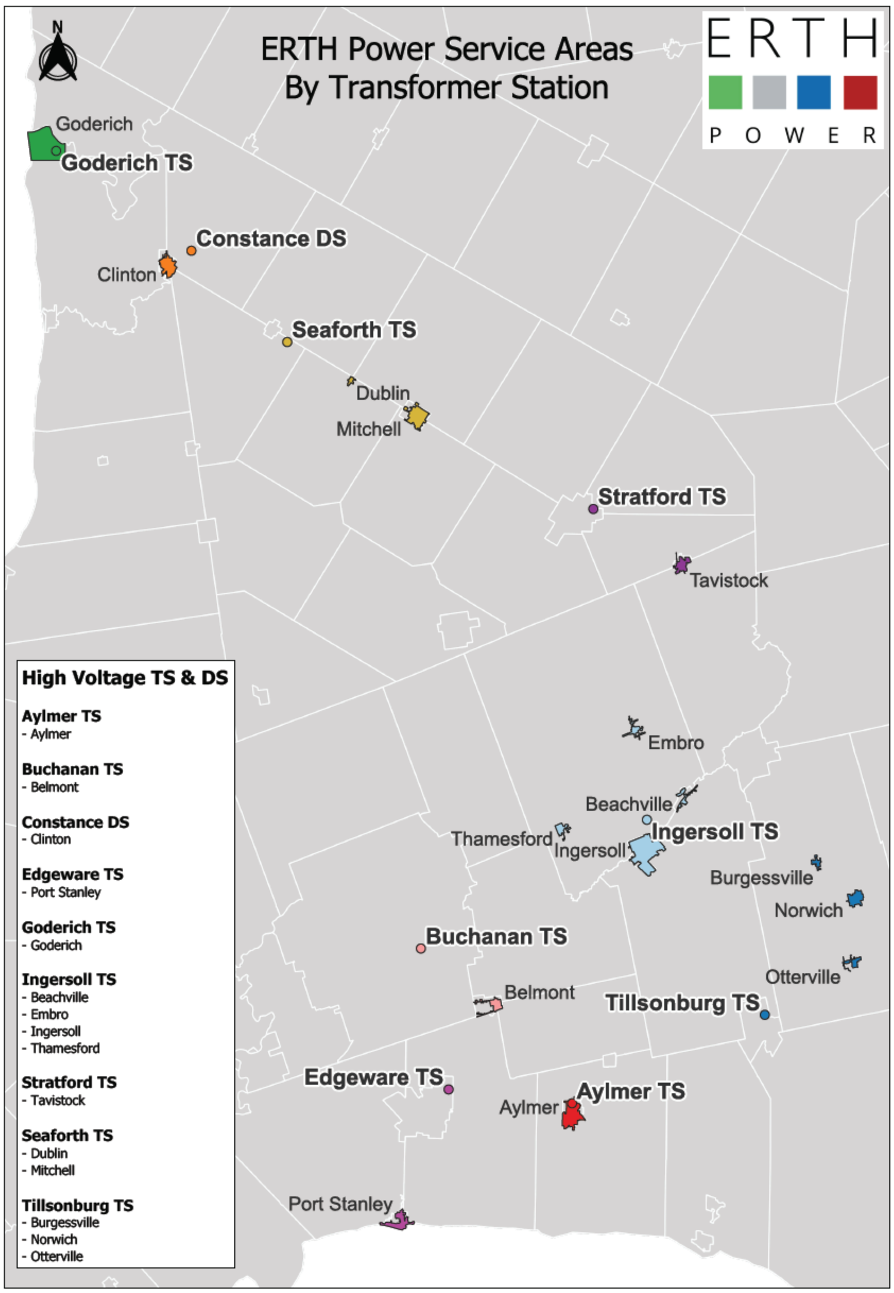
System Average Interruption Frequency Index (SAIFI): It is the number of non-momentary electric interruptions, per year, the average customer experienced.

Momentary Outages: typically refers to a brief interruption in electrical service, generally defined as an interruption of less than one minute in duration.

Major Event Days or Major Events (MEDs): a large event (single day or continuous) causing large customer outages (number and/or duration) that when evaluated as per the prescribed IEEE methodology can be separated when reporting reliability metrics.

2. System Overview

The majority of ERTH's fifteen (15) municipalities are embedded and supplied from various Hydro One distribution (DX) circuit(s) with the Town of Aylmer and the Town of Goderich having the only transmission (TX) connected supply points. ERTH is supplied by eight (8) Transmission Stations, one (1) high voltage Distribution Station, and three (3) Distribution Stations owned and operated by Hydro One In addition, ERTH owns ten (10) municipal substations, converting voltages from 27.6Y/16kV to 4.19Y/2.4kV.



28KV SUPPLY POINTS (HYDRO ONE DX OR TX CONNECTION)

Municipality	Hydro One Supply Station	Feeder ID
Aylmer	Aylmer TS	34M3
		34M4
		34M5
Beachville	Ingersoll TS	38M44
Belmont	Buchanan TS	19M21
	Belmont DS (via Buchanan M21)	BEL-F1
Burgessville	North Norwich DS (via Tillsonburg M3)	NNDS-F2
Clinton	Constance DS	CON-F2
		CON-F4
Dublin	Dublin DS (supplied by Seaforth TS)	DUB - F1 (61M2)
Embro	Ingersoll TS	38M46
Goderich	Goderich TS	31M3
		31M4
		31M5
Ingersoll	Ingersoll TS	38M49
		38M50
		38M51
		38M52
Mitchell	Seaforth TS	61M2
Norwich	Tillsonburg TS	20M3
Otterville	Tillsonburg TS	20M1
	Otterville DS (via Tillsonburg M1)	OTT-F1
Port Stanley	Edgeware TS	27M3
Tavistock	Stratford TS	68M7
Thamesford	Ingersoll TS	38M43 (legacy)
	Ingersoll TS	38M45

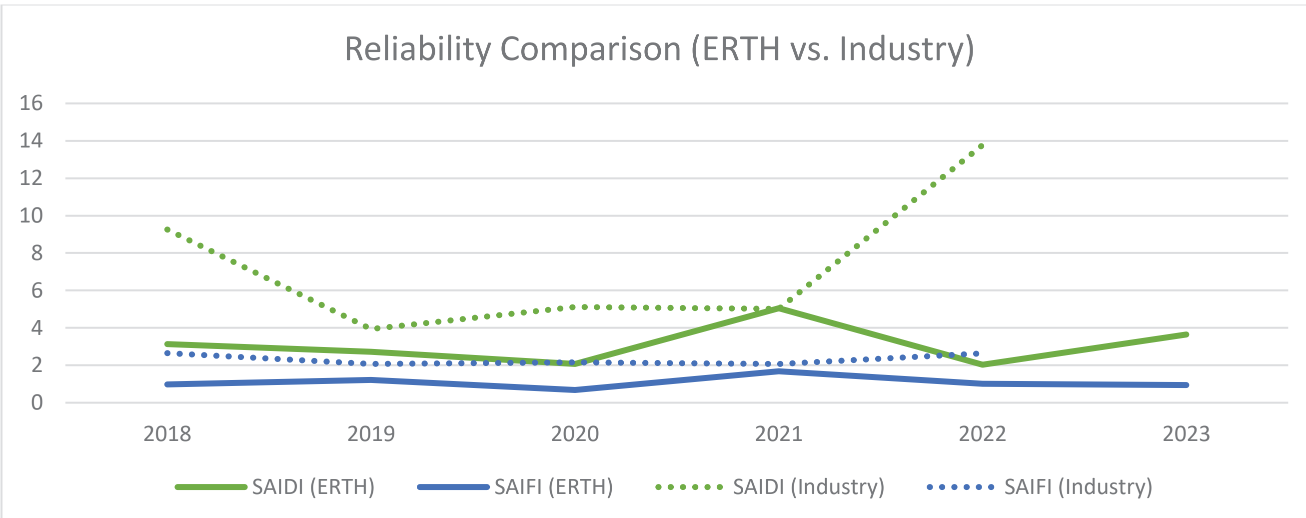
4KV SUPPLY POINTS (ERTH OWNED MUNICIPAL SUBSTATIONS)

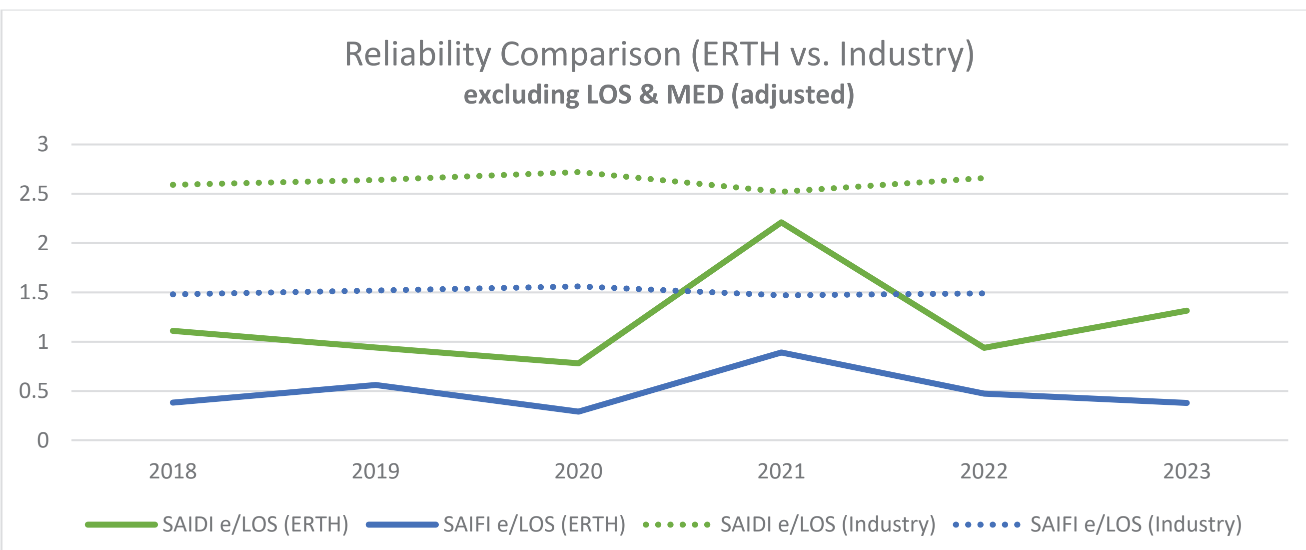
Municipality	Municipal Substation ID	Feeder ID(s)
Aylmer	MS1	AYL-1F1, AYL-1F2, AYL-1F3
	MS2	AYL-2F1, AYL-2F2, AYL-2F4
Beachville	MS1	BEA-1F1
Clinton	MS1	CLN-1F1, CLN-1F2, CLN-1F3
Ingersoll	MS1	ING-1F1, ING-1F3
Port Stanley	MS1	PTS-1F3
Tavistock	MS1	TAV-1F2, TAV-1F3
Goderich	MS2	GDE-2F2, GDE-2F3
	MS3	GDE-3F3, GDE-3F4
	MS4	GDE-4F1, GDE-4F3

3. Major Event Days or Major Events (MEDs)

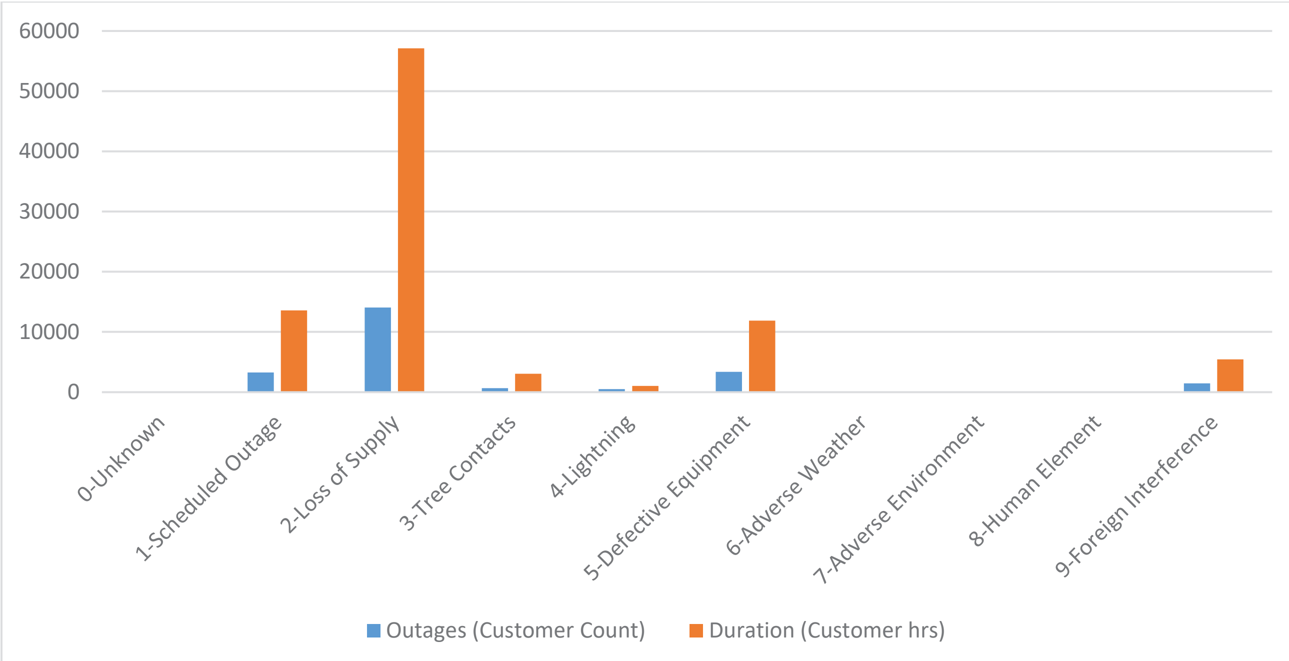
- No Major Event Days to report

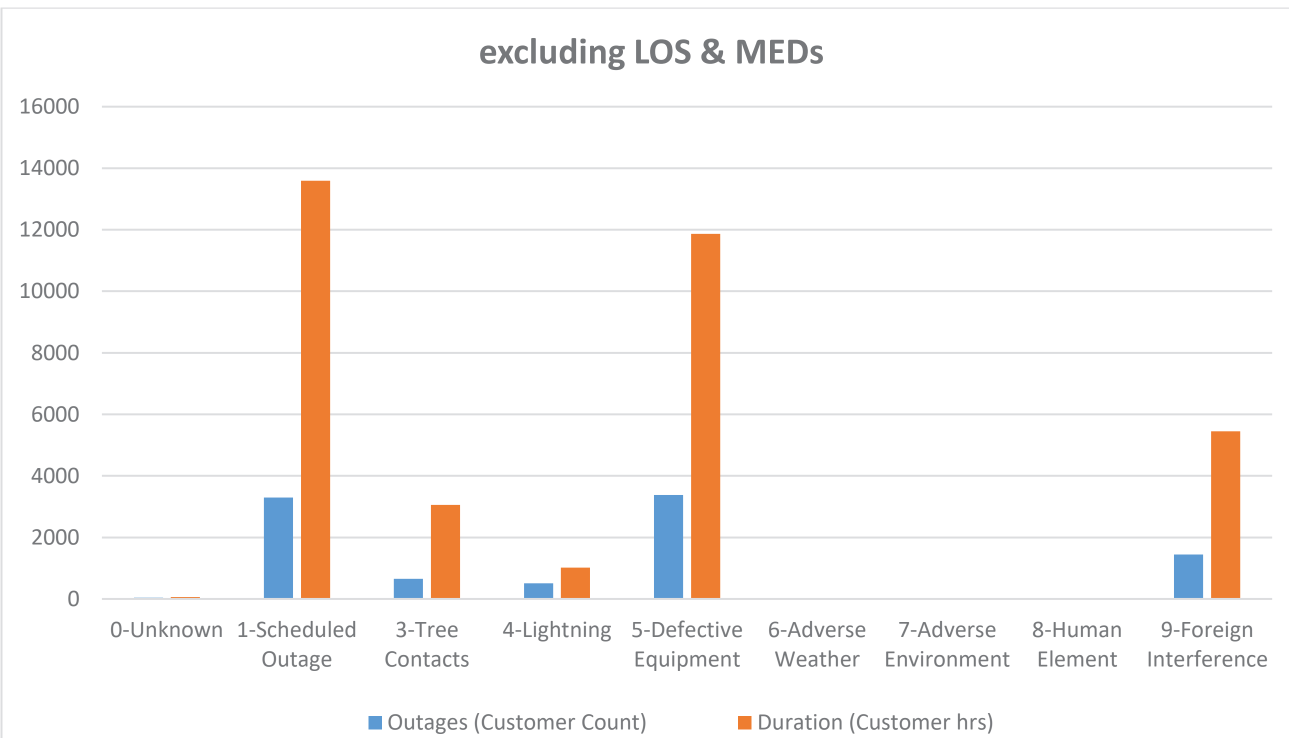
4. SAIDI & SAIFI (5 Year Comparison)



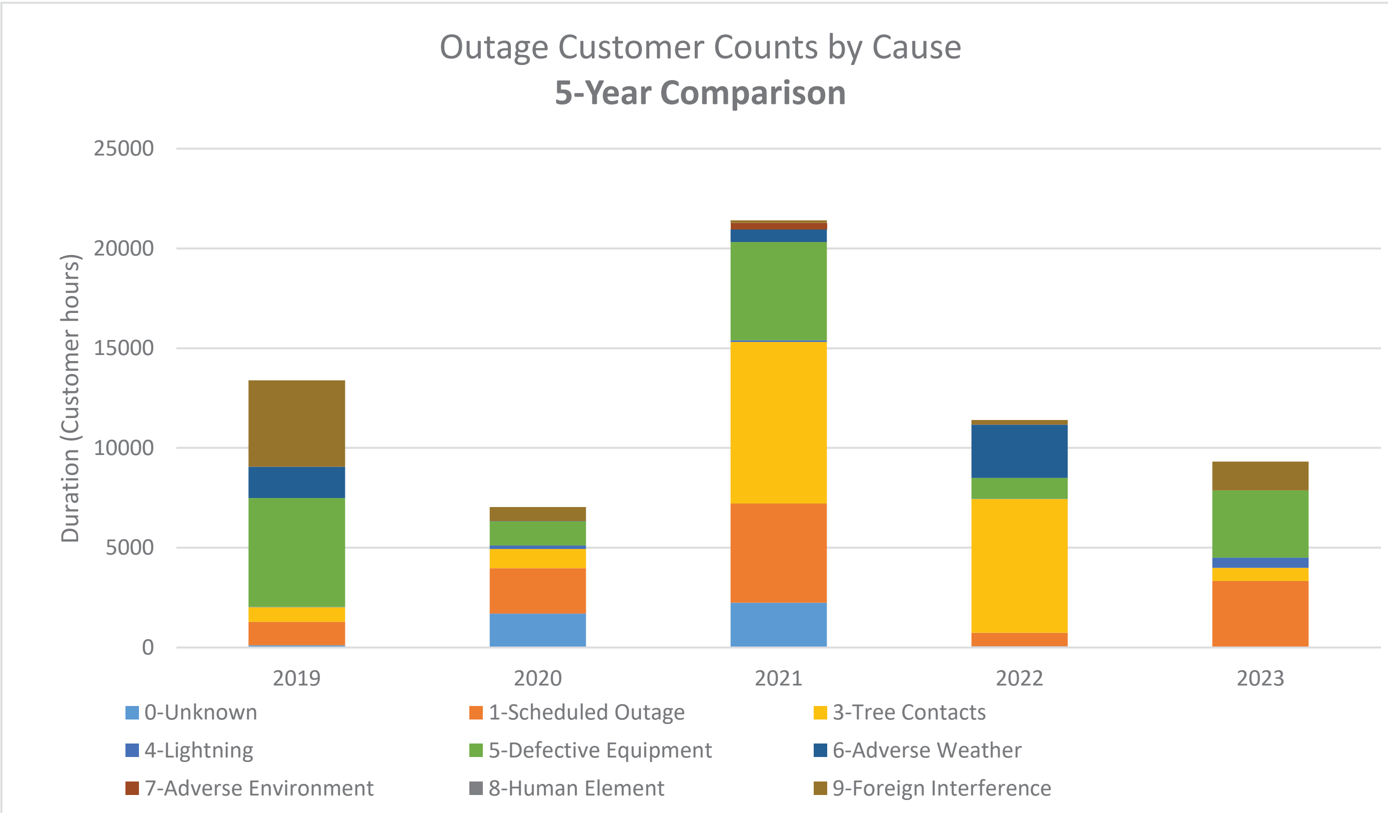


5. 2023 Outages by Cause



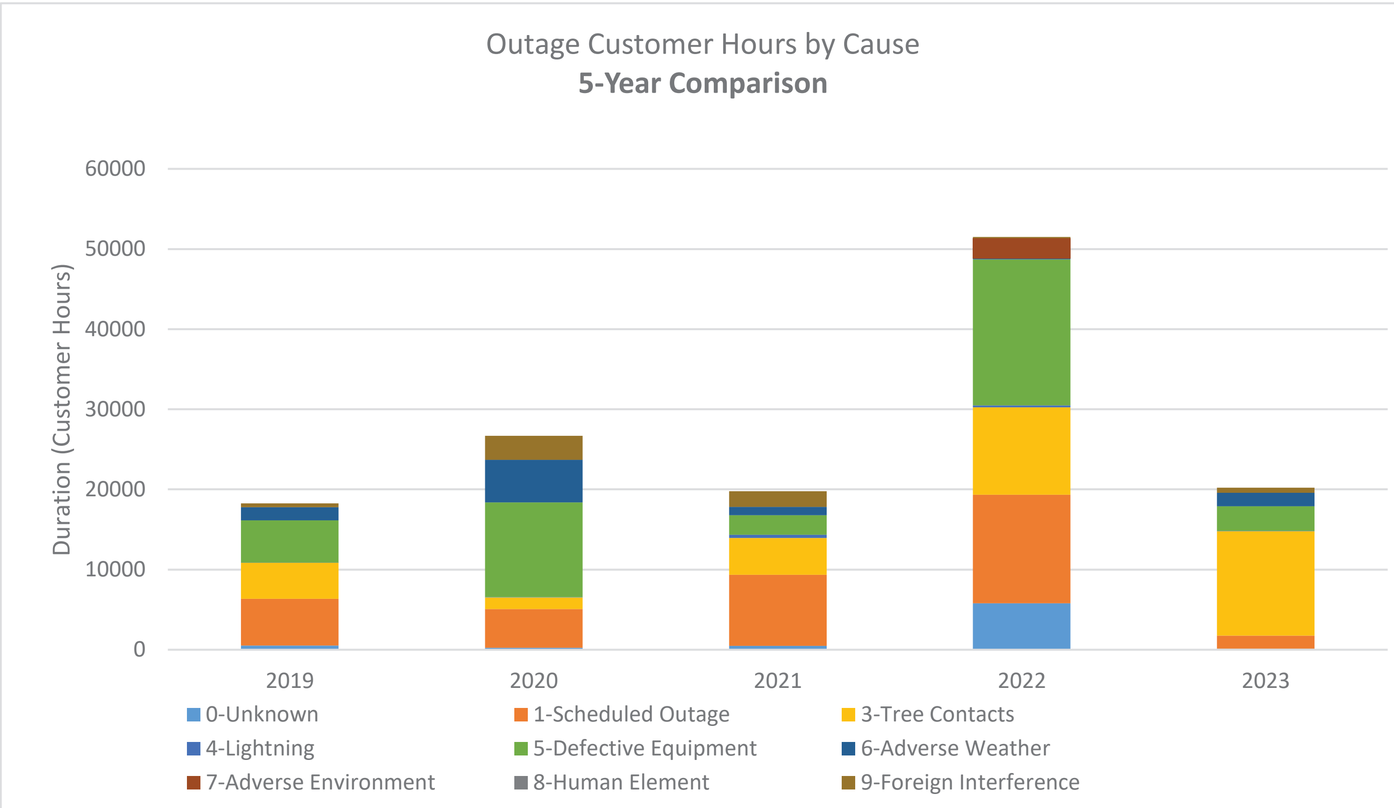


6. Five (5) Year - Outages by Cause



Frequency (Customer Count)

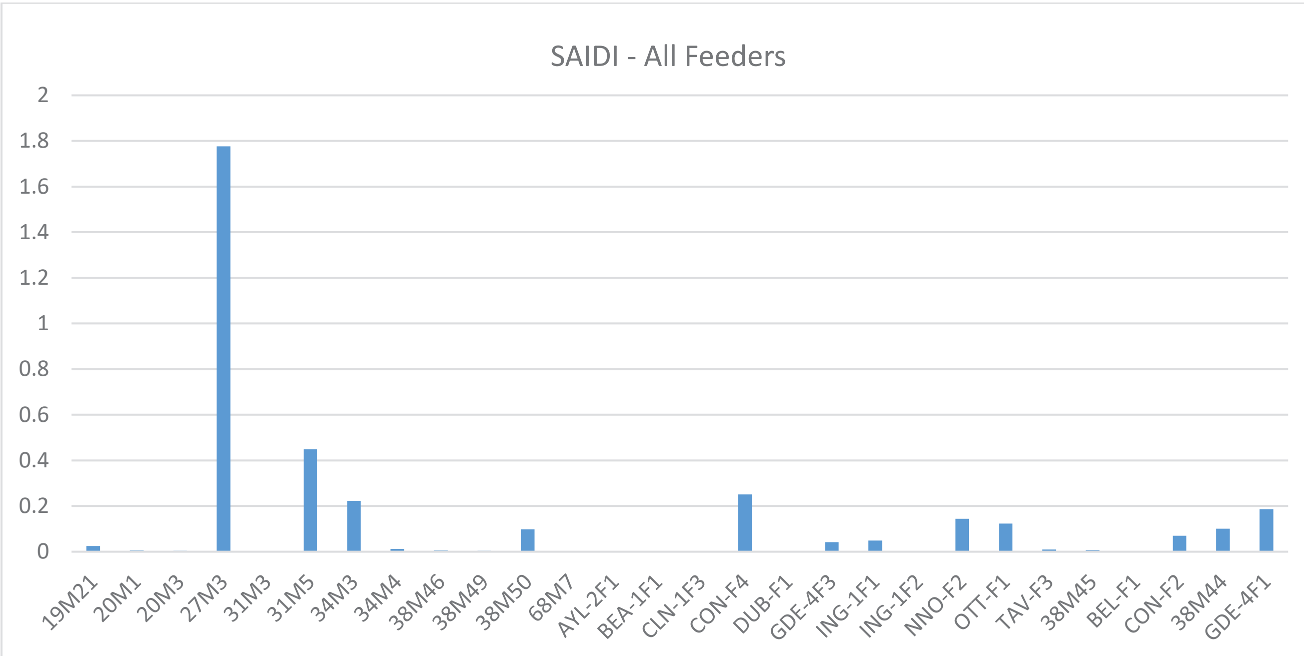
	2016	2017	2018	2019	2020	2021	2022	2023	Total	%
0-Unknown	448	28	402	109	1693	2249	69	41	5039	2.69%
1-Scheduled Outage	658	567	1371	1179	2285	4965	666	3299	14990	7.99%
2-Loss of Supply	12562	6422	11728	15830	9292	18861	12906	14079	101680	54.21%
3-Tree Contacts	5825	1688	1435	740	958	8094	6702	652	26094	13.91%
4-Lightning	0	175	1	3	185	94	18	511	987	0.53%
5-Defective Equipment	846	1616	2656	5452	1198	4917	1042	3378	21105	11.25%
6-Adverse Weather	1161	210	1511	1581	14	646	2665	0	7788	4.15%
7-Adverse Environment	0	0	0	0	0	311	0	0	311	0.17%
8-Human Element	0	0	0	0	0	0	20	0	20	0.01%
9-Foreign Interference	77	2597	85	4324	700	129	217	1441	9570	5.10%
Total	21577	13303	19189	29218	16325	40266	24305	23401	187584	100.00%

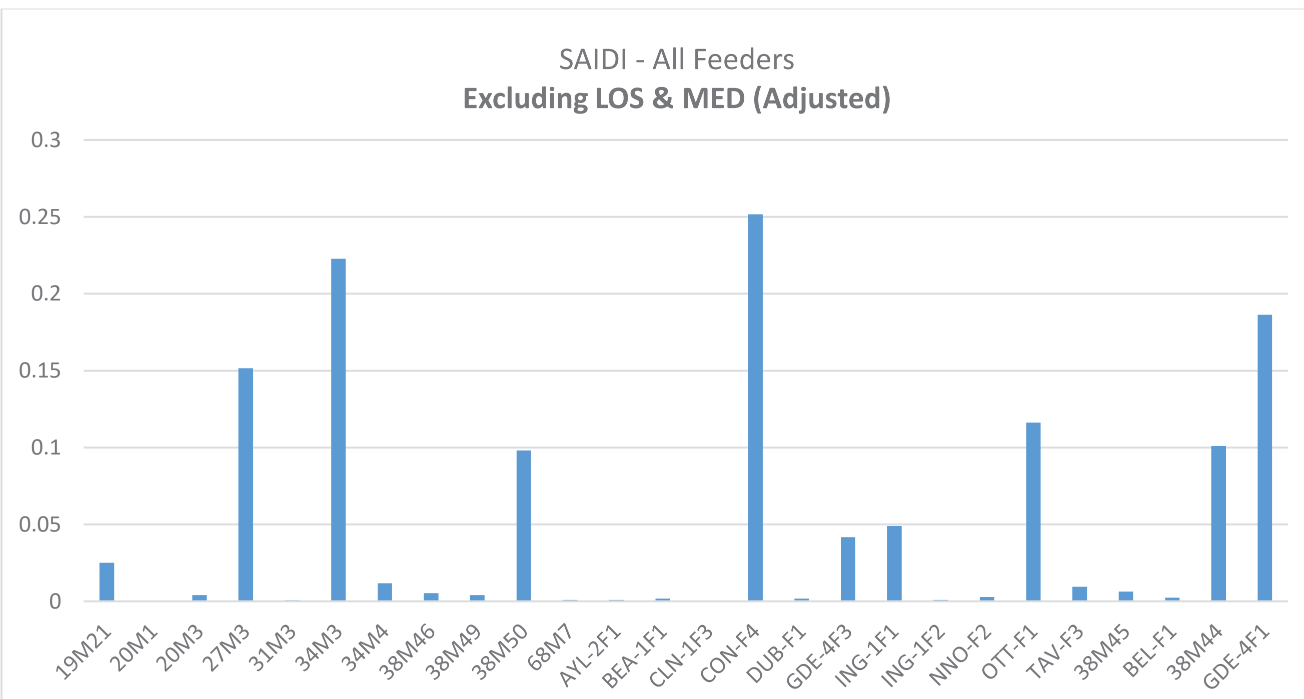


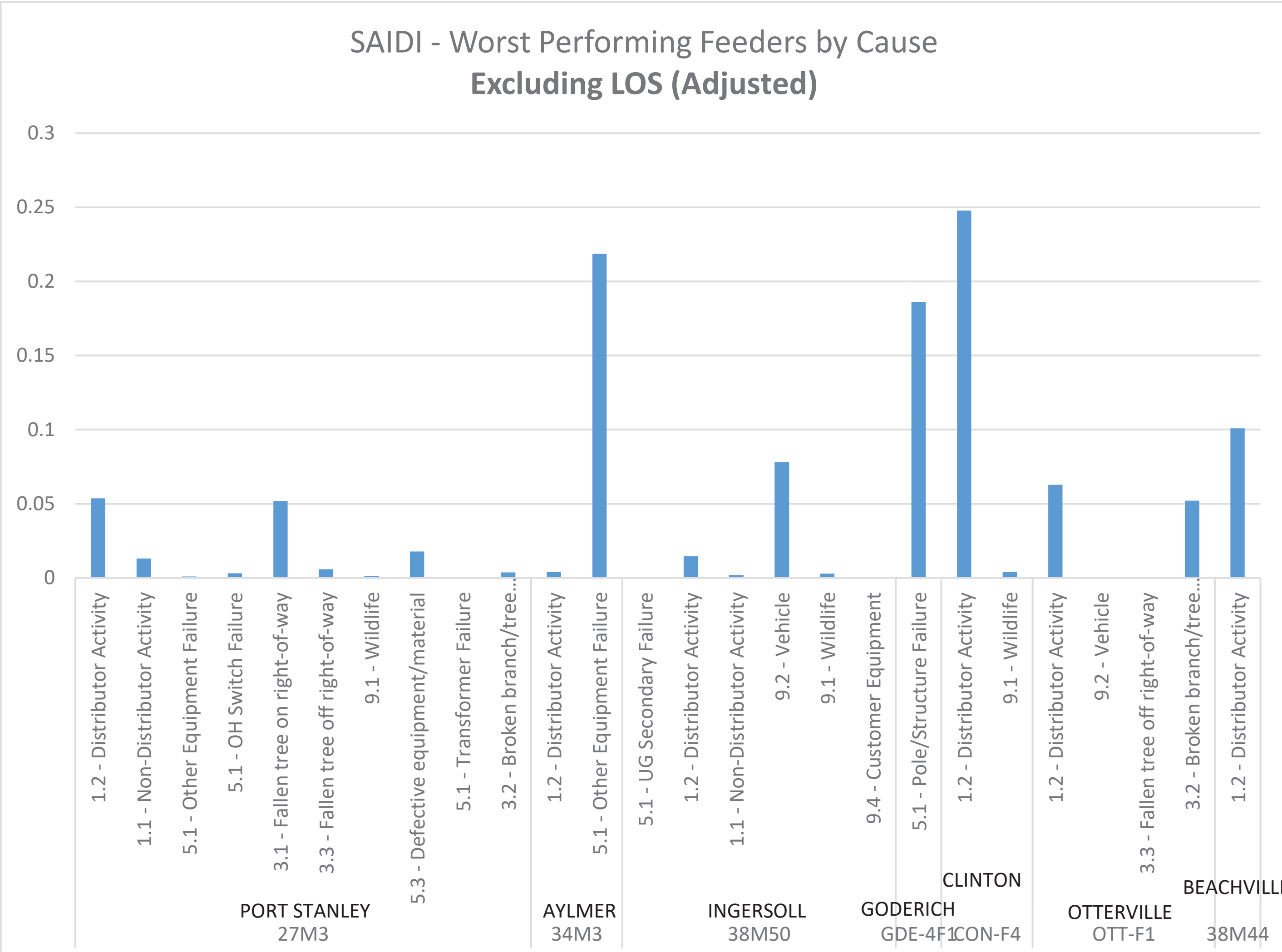
Duration (Customer hrs)

	2016	2017	2018	2019	2020	2021	2022	2023	Total	%
0-Unknown	1011	57	537	231	486	5800	124	61	8307	1.51%
1-Scheduled Outage	4472	2691	5836	4832	8852	13531	1631	13594	55439	10.06%
2-Loss of Supply	39869	18594	39803	42636	31467	67975	26440	57129	323913	58.75%
3-Tree Contacts	9851	2134	4512	1457	4605	10925	13038	3054	49577	8.99%
4-Lightning	0	294	1	23	387	218	40	1022	1985	0.36%
5-Defective Equipment	2021	4870	5243	11843	2463	18232	3056	11865	59593	10.81%
6-Adverse Weather	18338	1639	5318	1049	114	1687	4128	0	32273	5.85%
7-Adverse Environment	0	0	0	0	0	2532	0	0	2532	0.46%
8-Human Element	0	0	0	0	0	0	3	0	3	0.00%
9-Foreign Interference	202	5809	478	3007	1950	169	661	5444	17721	3.21%
Total	75764	36088	61728	65078	50324	121069	49121	92170	551342	100.00%

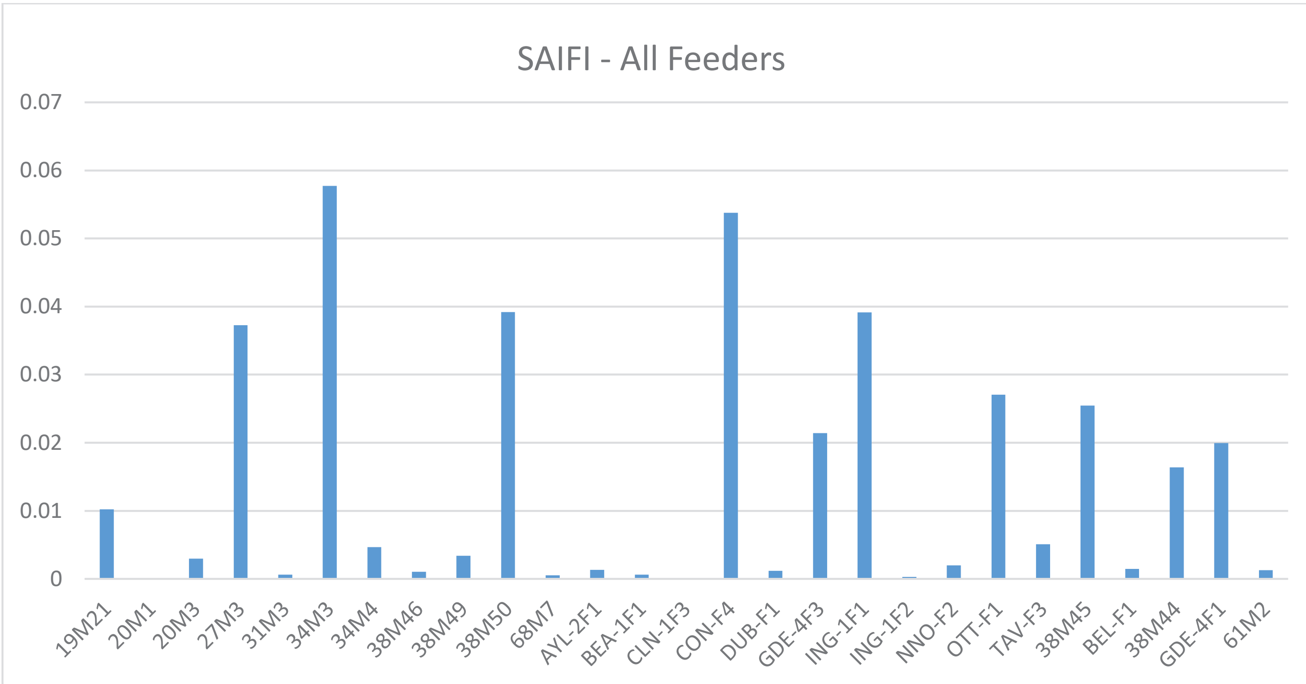
7. 2023 Worst Performing Feeder (SAIDI)

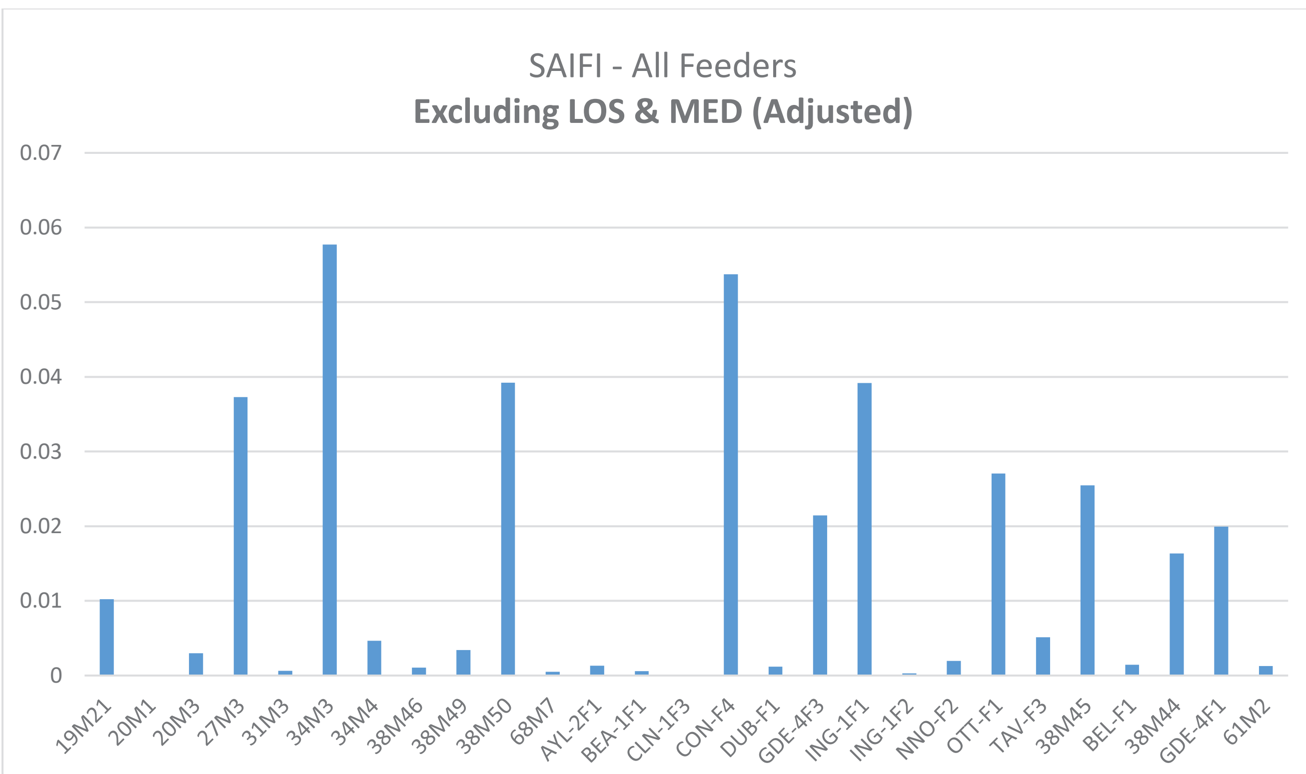


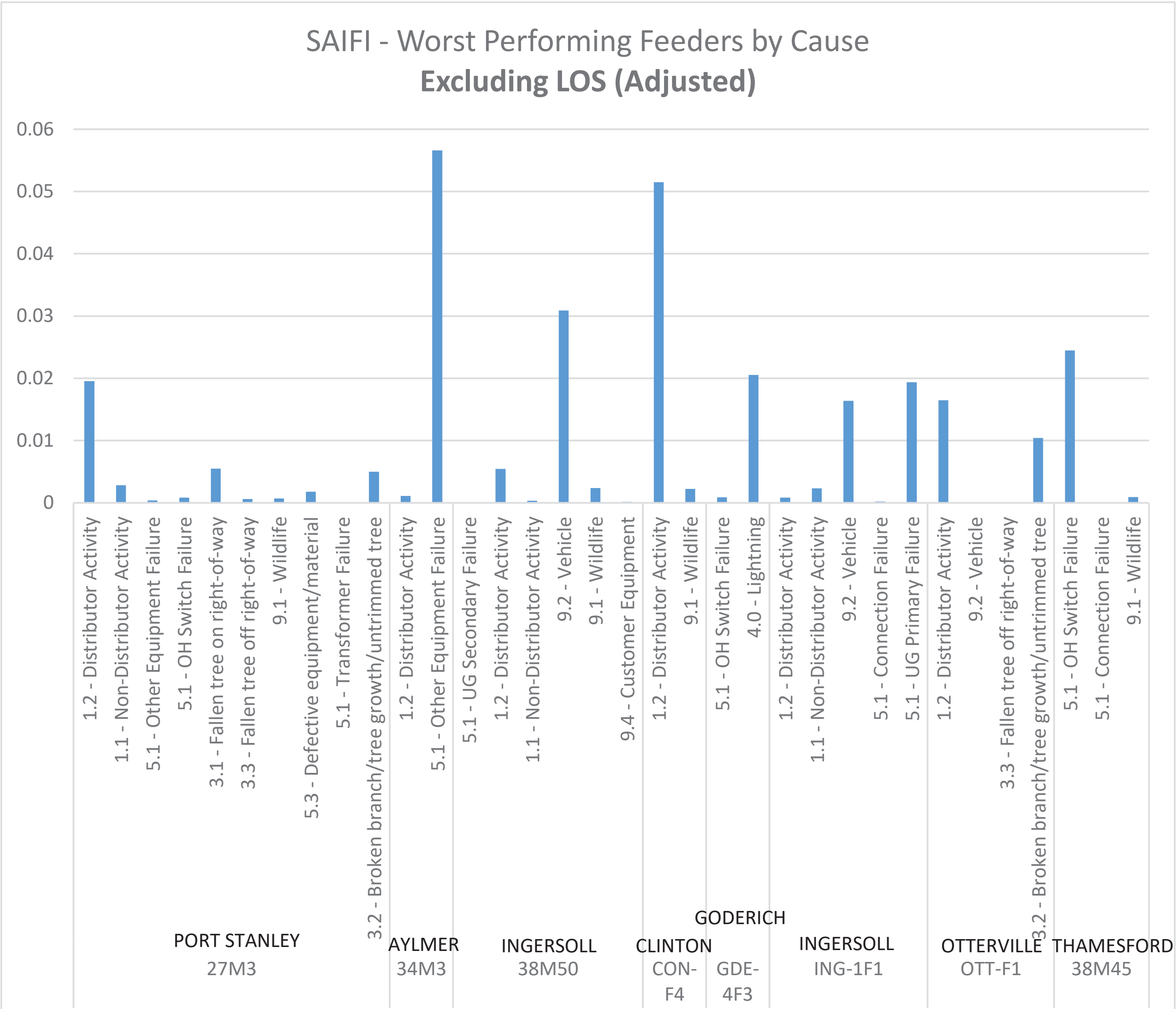



SAIDI - Worst Performing Feeders by Cause
Excluding LOS (Adjusted)
0.3
0.25
0.2
0.15
0.1
0.05
0
1.2 - Distributor Activity
1.1 - Non-Distributor Activity
5.1 - Other Equipment Failure
5.1 - OH Switch Failure
3.1 - Fallen tree on right-of-way
3.3 - Fallen tree off right-of-way
9.1 - Wildlife
5.3 - Defective equipment/material
5.1 - Transformer Failure
3.2 - Broken branch/tree...
1.2 - Distributor Activity
5.1 - Other Equipment Failure
5.1 - UG Secondary Failure
1.2 - Distributor Activity
1.1 - Non-Distributor Activity
9.2 - Vehicle
9.1 - Wildlife
9.4 - Customer Equipment
5.1 - Pole/Structure Failure
1.2 - Distributor Activity
9.1 - Wildlife
1.2 - Distributor Activity
9.2 - Vehicle
3.3 - Fallen tree off right-of-way
3.2 - Broken branch/tree...
1.2 - Distributor Activity
PORT STANLEY
27M3
AYLMER
34M3
INGERSOLL
38M50
GODERICH
GDE-4F1
CLINTON
CON-F4
OTTERVILLE
OTT-F1
BEACHVILLE
38M44

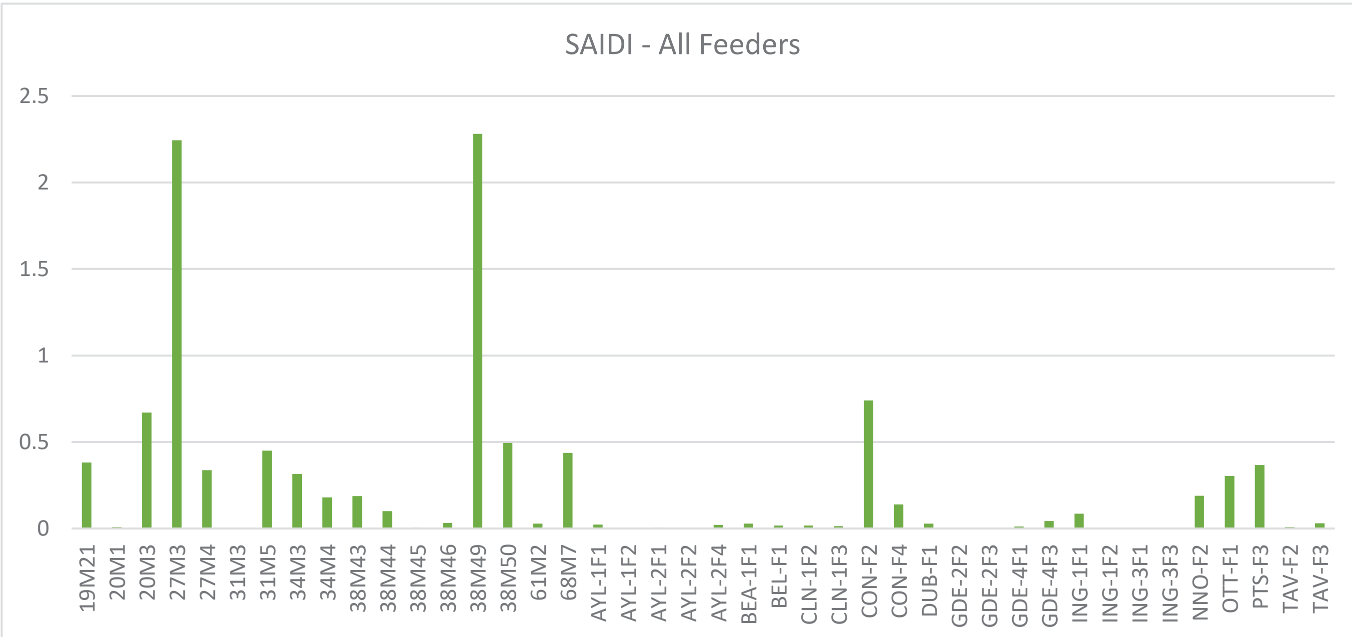
8. 2023 Worst Performing Feeders (SAIFI)

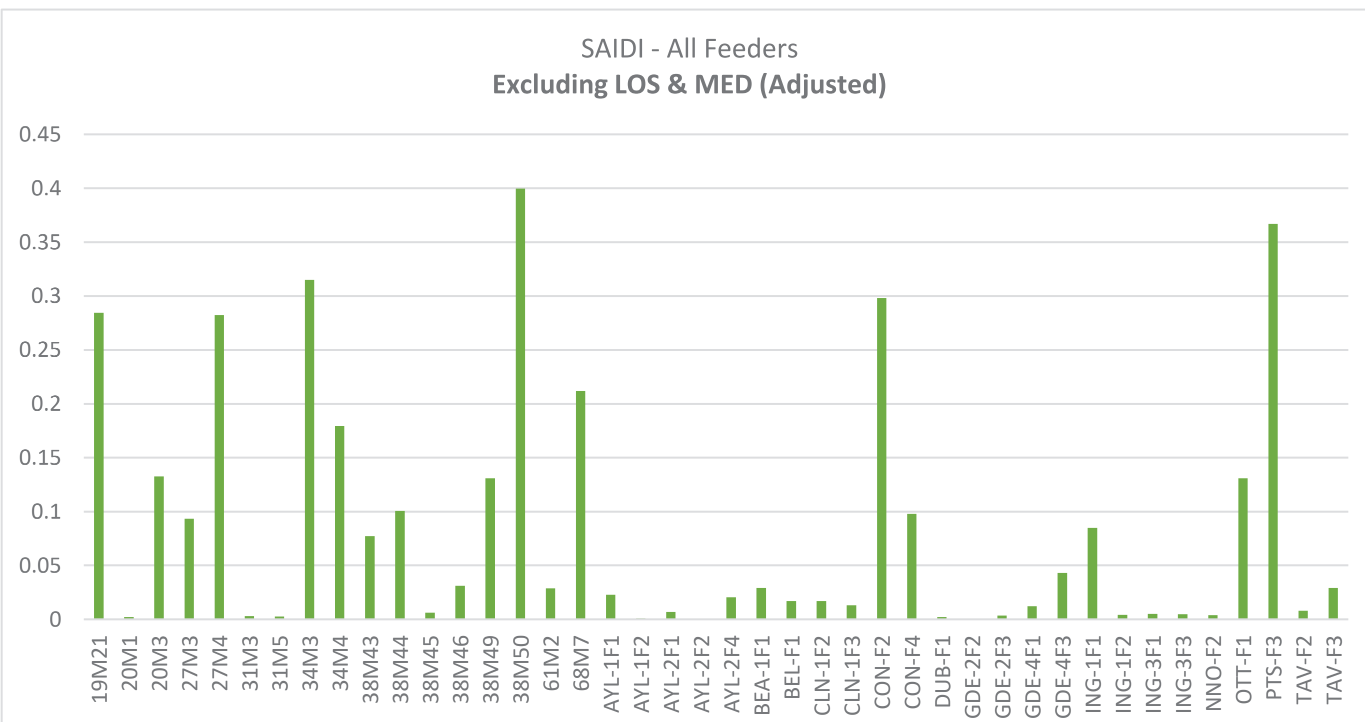


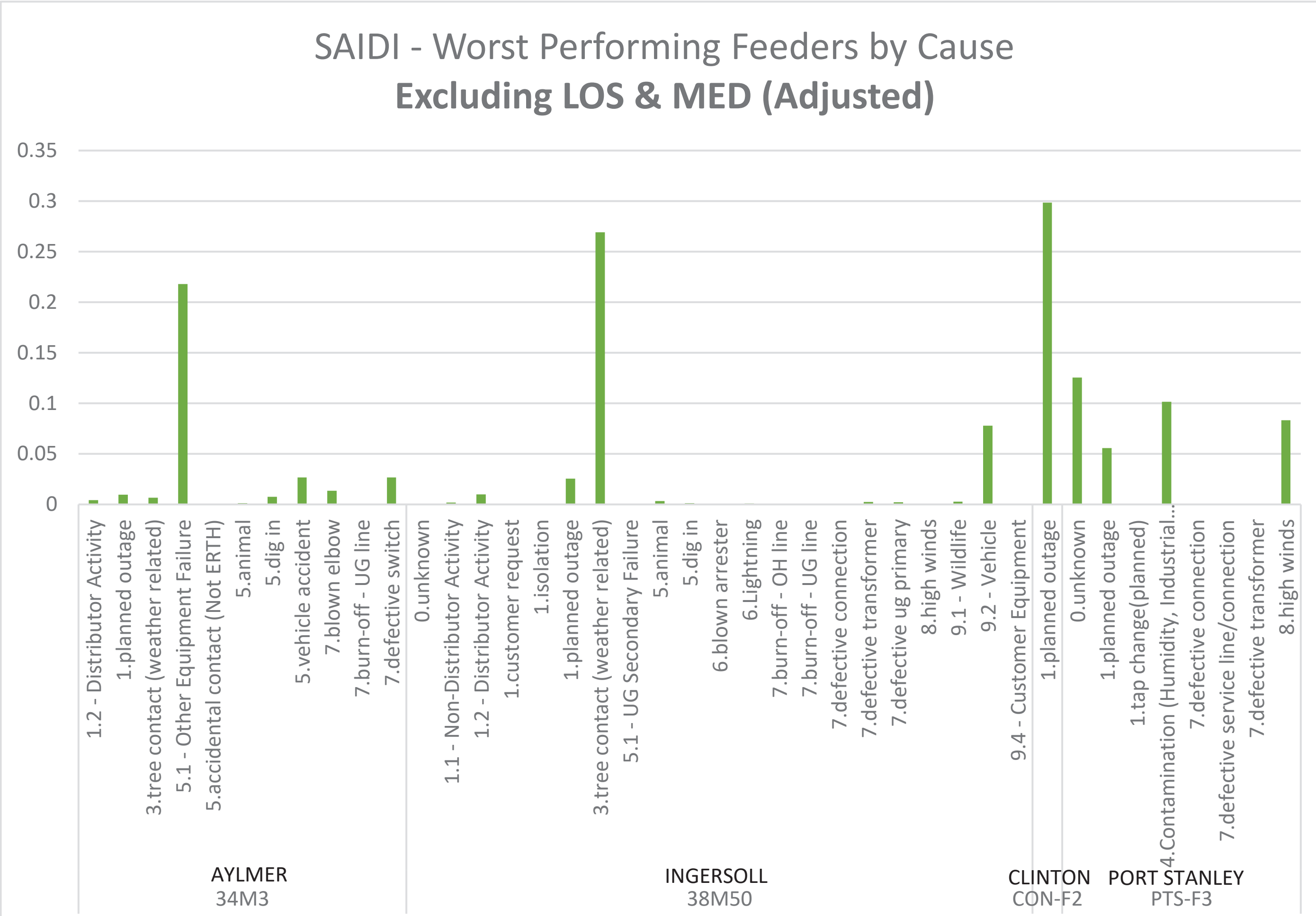



SAIFI - Worst Performing Feeders by Cause
Excluding LOS (Adjusted)
0.06
0.05
0.04
0.03
0.02
0.01
0
1.2 - Distributor Activity
1.1 - Non-Distributor Activity
5.1 - Other Equipment Failure
5.1 - OH Switch Failure
3.1 - Fallen tree on right-of-way
3.3 - Fallen tree off right-of-way
9.1 - Wildlife
5.3 - Defective equipment/material
5.1 - Transformer Failure
3.2 - Broken branch/tree growth/untrimmed tree
1.2 - Distributor Activity
5.1 - Other Equipment Failure
5.1 - UG Secondary Failure
1.2 - Distributor Activity
1.1 - Non-Distributor Activity
9.2 - Vehicle
9.1 - Wildlife
9.4 - Customer Equipment
1.2 - Distributor Activity
9.1 - Wildlife
5.1 - OH Switch Failure
4.0 - Lightning
1.2 - Distributor Activity
1.1 - Non-Distributor Activity
9.2 - Vehicle
5.1 - Connection Failure
5.1 - UG Primary Failure
1.2 - Distributor Activity
9.2 - Vehicle
3.3 - Fallen tree off right-of-way
3.2 - Broken branch/tree growth/untrimmed tree
5.1 - OH Switch Failure
5.1 - Connection Failure
9.1 - Wildlife
PORT STANLEY
27M3
AYLMER
34M3
INGERSOLL
38M50
CLINTON
CON-F4
GODERICH
GDE-4F3
INGERSOLL
ING-1F1
OTTERVILLE
OTT-F1
THAMESFORD
38M45

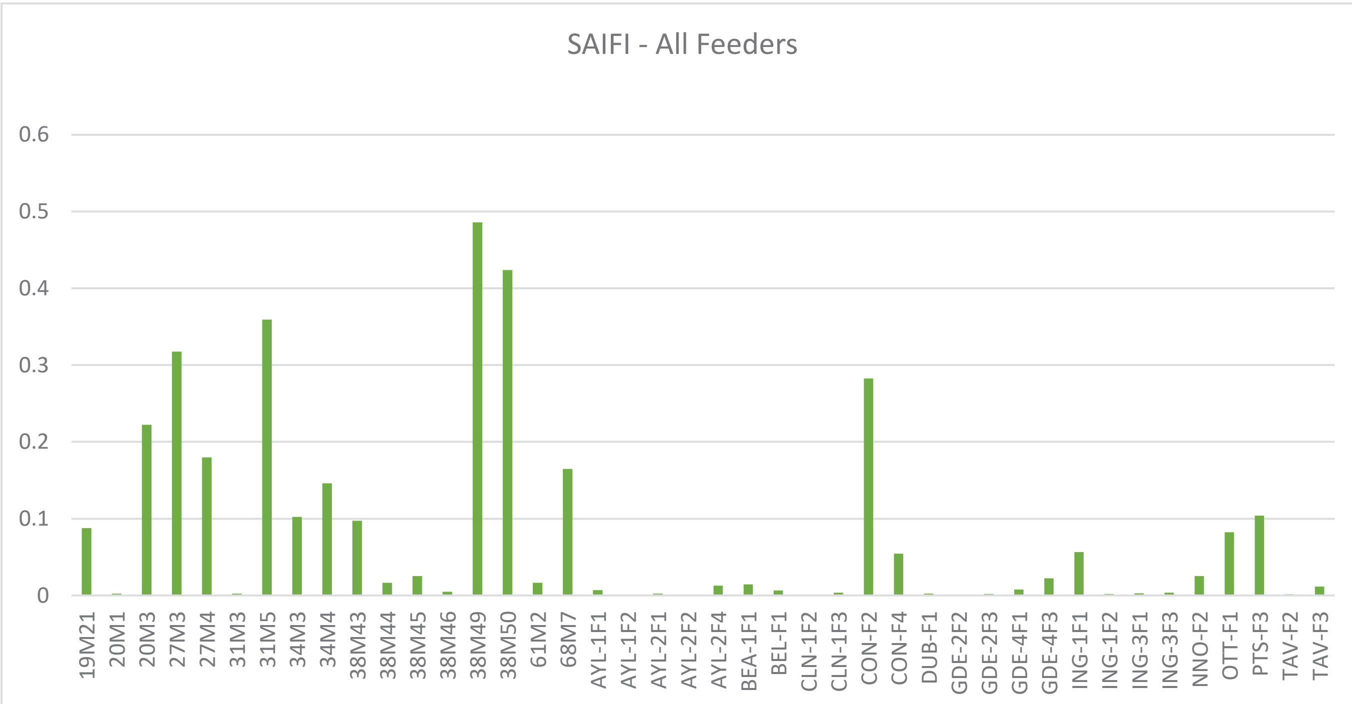
9. 2020 - 2023 Worst Performing Feeder (SAIDI)

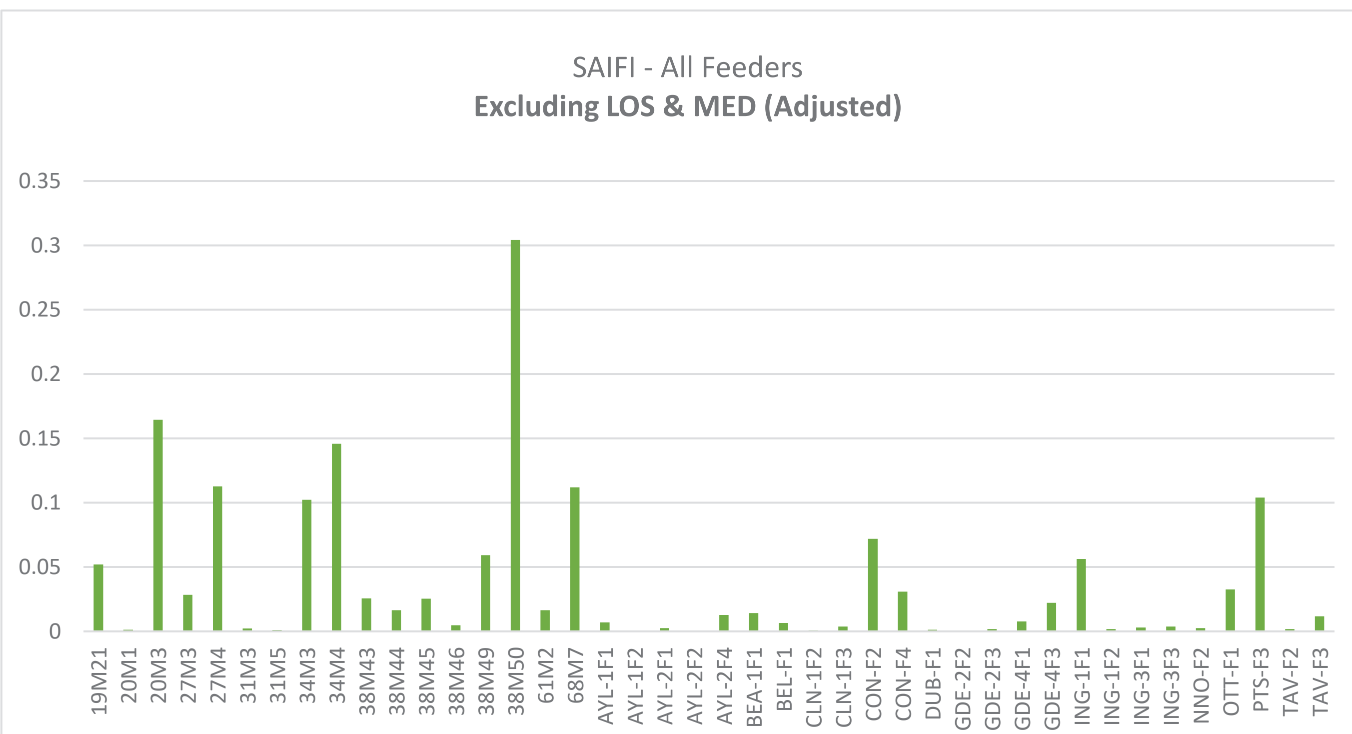


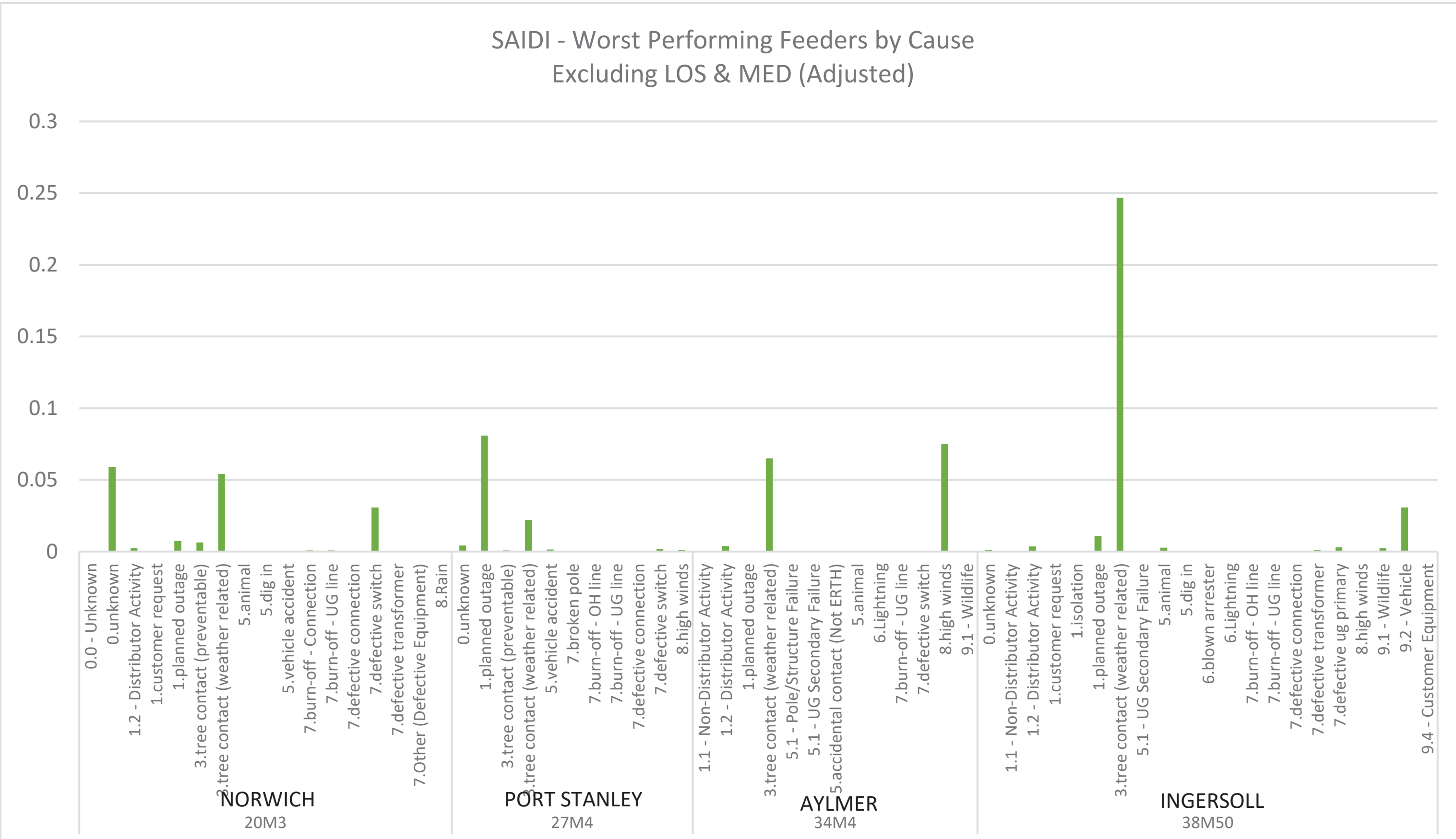



SAIDI - Worst Performing Feeders by Cause
Excluding LOS & MED (Adjusted)
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
1.2 - Distributor Activity
1.planned outage
3.tree contact (weather related)
5.1 - Other Equipment Failure
5.accidental contact (Not ERTH)
5.animal
5.dig in
5.vehicle accident
7.blown elbow
7.burn-off - UG line
7.defective switch
0.unknown
1.1 - Non-Distributor Activity
1.2 - Distributor Activity
1.customer request
1.isolation
1.planned outage
3.tree contact (weather related)
5.1 - UG Secondary Failure
5.animal
5.dig in
6.blown arrester
6.Lightning
7.burn-off - OH line
7.burn-off - UG line
7.defective connection
7.defective transformer
7.defective ug primary
8.high winds
9.1 - Wildlife
9.2 - Vehicle
9.4 - Customer Equipment
1.planned outage
0.unknown
1.planned outage
1.tap change(planned)
4.Contamination (Humidity, Industrial…
7.defective connection
7.defective service line/connection
7.defective transformer
8.high winds
AYLMER
34M3
INGERSOLL
38M50
CLINTON
CON-F2
PORT STANLEY
PTS-F3

10. 2020 - 2023 Worst Performing Feeder (SAIFI)







11. Momentary Outages by Feeder

- Not currently analyzed

12. Analysis

- ERTH is generally performing better than industry standards comparing overall SAIDI and SAIFI metrics to other LDC's

- **Loss of Supply Outages** are the largest cause of outages affecting ERTH Power Customers
  - SAIFI (frequency) - **54%** of the total customer outages are **LOS** since 2016.
  - SAIDI (duration) - **59%** of the total customer hours are **LOS** since 2016.

- Excluding Loss of Supply the largest cause of outages are Defective Equipment, Tree Contacts & Scheduled Outages since 2016.
  - SAIFI (frequency) - **14%** of the total customer outages are **Tree Contacts**
    - **11%** of the total customer outages are **Defective Equipment**
  - SAIDI (duration) - **10%** of the total customer outages are **Scheduled Outages**
    - **11%** of the total customer outages are **Defective Equipment**

- Worst Performing Feeder(s) for **SAIDI (Duration)** - 2020 to 2023
  - **Including LOS** the 27M3 (Port Stanley) and the 38M49 (Ingersoll) have been the worst performing feeders.
  - **Excluding LOS** the 38M50 (Ingersoll), 34M3 (Aylmer), CON-F2 (Clinton) and PTS-F3 (Port Stanley) have been the worst performing feeders
    - 38M50 - Tree Contact (weather related)
    - 34M3 - Equipment Failure
    - CON-F2 - Planned Outage (MS1 Maintenance)
    - PTS-F3 - Various Causes

- Worst Performing Feeder(s) for **SAIFI (Frequency)** - 2020 to 2023
  - **Including LOS** the 38M50 (Ingersoll), 38M49 (Ingersoll), 31M5 (Goderich) and 27M3 (Port Stanley) have been the worst performing feeders.
  - **Excluding LOS** the 38M50 (Ingersoll), 20M3 (Norwich), and 34M4 (Aylmer) have been the worst performing feeders
    - 38M50 - Tree Contact (weather related)
    - 20M3 - Tree Contact (weather related), Defective Switch & Unknown
    - 34M4 - Tree Contact (weather related), High Winds

13. Recommendations (O&M, Capex etc.)

- Generally one large outage drives WPF's even when considering multiple years; especially on feeders with more customers.
- Review tree trimming schedule and cutbacks
- Increased pole replacement budget to catch up on bad condition poles
- Porcelain switch replacement programs in capital and as a trouble call policy
  - Supply chain issues make this a difficult solution on 27kV
- Reduce Scheduled Outages via Mobile Substation investment

14. Develop for Future

- Outages shown in a graphical format (GIS Mapping)
- Recommendation Tracking.
- Momentary Outages - tracking & analysis - investigating options in SCADA system

APPENDIX G. Asset Condition Assessment Report (2024)

ERTH Power Corporation

2024 Asset Condition Assessment

BBA Document No. / Rev.: 8560001-40-ERA-0001 / R0
Client Document No.: 0001
May 21st, 2024

Revision 0

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BBA Document No. / Rev.: 8560001-40-ERA-0001 / R0

REVISION HISTORY

Revision	Document Status – Revision Description	Date
IFR	Issued for Review	2024-04-26
R0	Revision 0	2024-05-21

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Executive Summary

This report relays the findings of an Asset Condition Assessment ("ACA") of select distribution and station assets of ERTH Power Corporation ("ERTH") – a licensed electricity distributor operating in southwestern Ontario. Aside from relaying the results of the quantitative assessment of the available asset demographics and condition data, the report also discusses the role of the ACA in the utility Asset Management ("AM") frameworks. The report concludes with a series of recommendations related to the incremental enhancement of ERTH's data collection practices and recommends several potential AM metrics that the utility may wish to implement to track the progress of its enhancements in the AM space and derive new operating and strategic insights.

Context of the Study

ERTH engaged BBA E&C Inc. ("BBA") to complete an ACA study. ERTH aims to understand the current health of key distribution and station assets. To assist ERTH in this work, this report includes an expanded discussion on the role that ACA results play in the modern evidence-based AM frameworks and provides a series of recommendations aimed at the establishment of a comprehensive and sustainable AM practice over time.

ERTH has taken steps to consolidate the data collection and analysis practices across its service territory, enabling it to undertake consistent asset health analysis in current and future ACA iterations.

Being a relatively new phenomenon in Ontario's electricity distribution sector, quantitative ACA studies such as this report continue encountering material data availability gaps, both in terms of availability of specific types of information commonly expected in asset HI formulations and availability of data across the entire asset base. This report is not an exception to this relatively common – but generally improving – data availability trend. In the instances where data gaps within a given asset class did not enable us to calculate asset HIs for the entire population, BBA identified these assets as having an "Invalid HI" in the respective sections presenting the results of our assessment.

In most cases, the above classification signals the fact that a given asset does not currently have the requisite number of recorded HI parameters to meet the data availability threshold commonly employed in the industry.

Scope of the Study

Our study covers ten asset classes, which collectively represent the bulk of material assets owned by the utility.

- Overhead system assets:
  - Wood poles;
  - Concrete poles;
  - Steel poles;
  - Pole-mounted transformers; and
  - Overhead switches.
- Underground system assets:
  - Underground cable;
  - Pad-mounted transformers;
  - Pad-mounted distribution switchgear; and
  - Junction boxes.
- Station assets:
  - Station power transformers.

Methodology and Findings

For all asset classes that underwent assessment, BBA used a consistent scale of asset health, containing five categories – from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, given as a score from 0 to 100. The HI formulations for individual asset classes represent weighted averages of numerical scores for individual HI subcomponents, known as degradation factors, scored on a scale from 0 to 100. The numerical score ranges, condition categories, and typical characteristics of an asset are described in Table 1.

Table 1: Definition of HI Scores

Score (%)	Condition Category	Description
85-100	Very Good	Some evidence of aging or minor deterioration of a limited number of components
70-85	Good	Significant deterioration of select components to be managed through normal maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components
30-50	Poor	Widespread serious deterioration across multiple components
0-30	Very Poor	Extensive serious deterioration – an asset has reached its end-of-life

The relative contribution of various degradation factor scores on the aggregate HI results is a function of weighting – assigned by an engineer to each HI subcomponent prior to commencing calculations. Using this methodology, BBA calculated HI results for every asset class in the scope of our assessment. BBA's findings for each asset class developed using this methodology are provided in Figure 1 and are also described in more detail in Section 4. The findings were also extrapolated to cover the asses with an Invalid HI as shown in Figure 2.

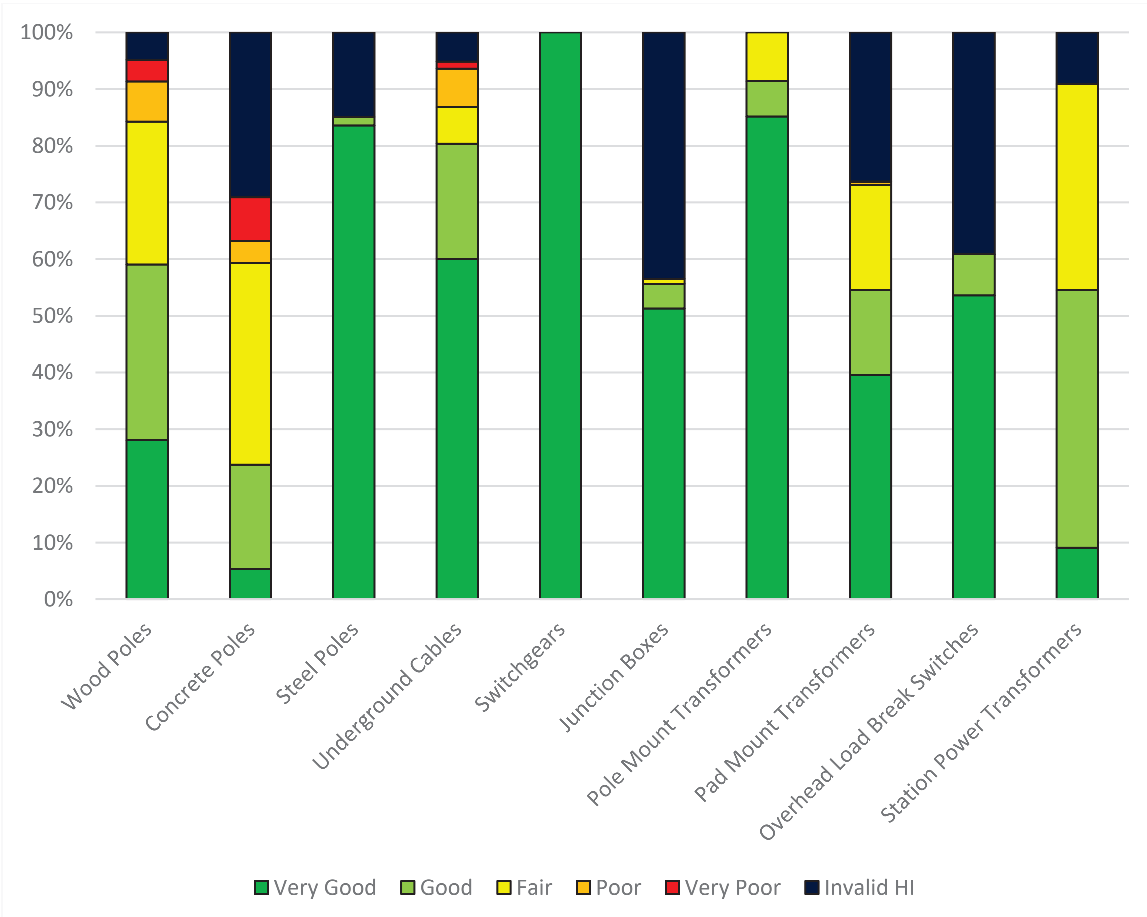

Figure 1: Overall Asset Condition Assessment Results

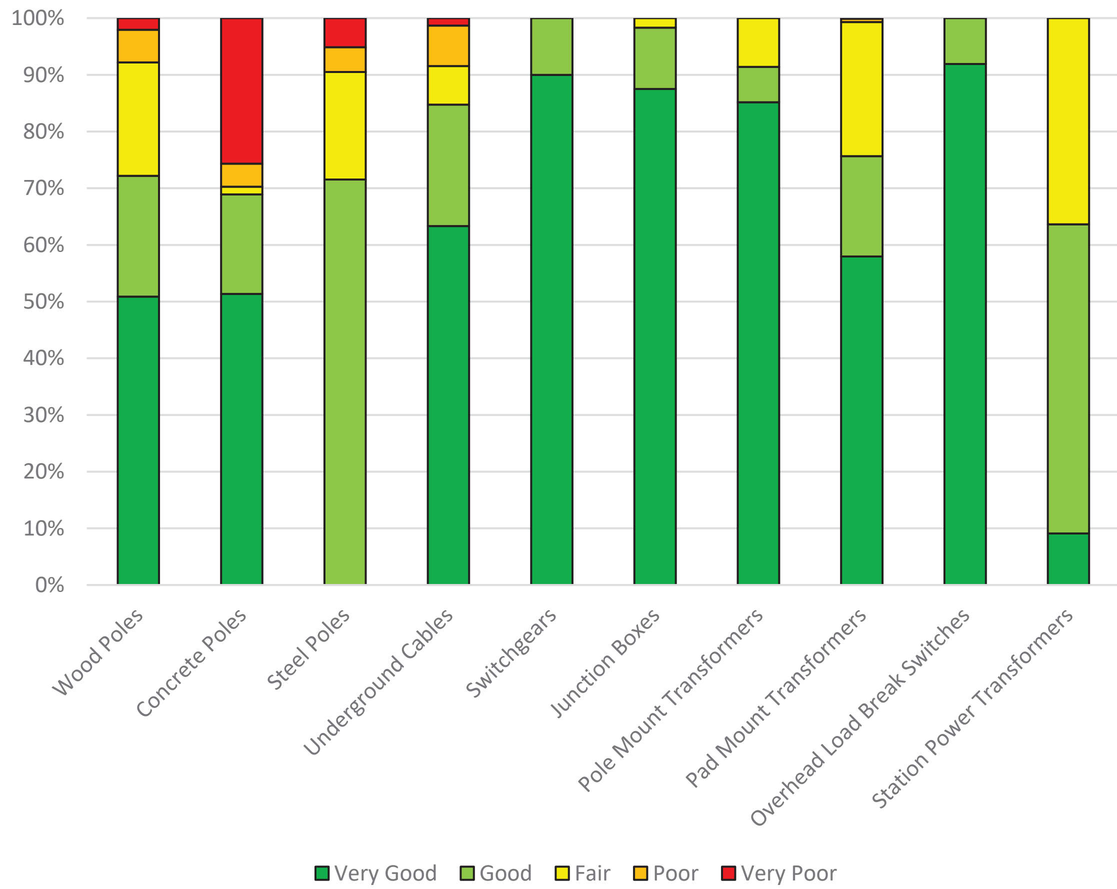

Figure 2: Extrapolated Asset Condition Assessment Results

As the above figures indicate, the vast majority of ERTH's assets are in Good condition or better based on our assessment, with relative contributions of Poor or Very Poor components being relatively minor and not indicative of extensive deterioration across the system or any concerns with the manner in which assets have been managed in the past.

Notably, there are several municipalities within ERTH's service area that could benefit from extra attention during inspections and are good candidates for asset replacements or refurbishment projects. These municipalities are Aylmer, Goderich, and Ingersoll. These municipalities host the largest quantity of assets in Fair to Very Poor condition and are also likely to contain a large portion of assets with unknown locations. In Aylmer, there are approximately 525 wood poles in Fair or worse condition as well as 36 and 57 Fair condition pole mount and pad mount transformers, respectively. Goderich has 313 wood poles in Fair or worse condition, 69 pole mount transformers in Fair condition, and 47 pad mount transformers in Fair or worse condition. Ingersoll has 464 wood poles in Fair or worse condition, 20 steel poles in Fair or worse condition, and approximately 9 km of underground cables in Fair or worse condition.

Certain asset classes have Invalid HI scores corresponding to the individual units where the number of available data inputs falls below the required threshold – below which the HI cannot be reliably calculated.

ERTH's Current Health Index Maturity and Continuous Improvement

In a couple cases, ERTH's current asset data records contain less than three degradation factors for each asset class – a numerical threshold that qualifies an asset health score to be formally viewed as an Asset HI. In these cases, we labelled the results of our analysis as two-parameter assessments but presented the results across all asset classes in a consistent format. Overall, we found ERTH to have a material amount of data that enabled us to conduct analysis that should yield meaningful managerial insights to the utility's planners.

With respect to the core distribution utility assets like station power transformers, we were able to construct relatively advanced multi-factor health indices. While comparatively less information is available for some other asset classes, the lack of availability or data diversity relative to other distributors' practices need not be automatically equated to a gap or an oversight on the part of the utility. As with other operating dimensions, utility decisions regarding the scope of data collection represent strategic trade-offs in the environment of multiple priorities and constrained operating costs.

As we note at the outset of this study, ERTH is relatively early into its existence, with a long-term approach to AM data collection, and use in decision-making remaining under development. BBA fully expects ERTH to consolidate its asset condition collection and analysis activities to determine which additional parameters (if any) it will collect going forward. We expect that ERTH will make these determinations based on the recommendations contained in this report, balancing the improvement considerations with the opportunity cost of other activities it will be required to undertake.

1. Introduction

ERTH Power Corporation ("ERTH" or "the utility") serves approximately 25,000 customers within the municipalities of Aylmer, Port Stanley, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Clinton, Mitchell, Dublin and Goderich. BBA E&C Inc. ("BBA") developed a health index ("HI") framework for ERTH's fixed electrical distribution and substation assets. To assist ERTH with further asset condition data efforts, Section 5 of this report contains a set of recommendations for the utility's management to consider going forward.

In preparation of this report, BBA relied on the following data sources:

- Asset inspection and testing data collected by ERTH staff or external contractors;
- Trouble reports for certain types of equipment completed by employees; and
- Interviews with ERTH's engineering and asset management ("AM") staff.

BBA employed an objective threshold-based approach related to the percentage of assets for which data was available to determine whether a given parameter would be included in the Health Index ("HI") calculation as per the broadly accepted methodology. BBA recommends that ERTH's AM function concentrate its efforts on ensuring that the data already being collected for some assets is captured for all the assets in the system rather than investing in new types of asset information.

To assist ERTH in its ongoing work to define the scope and nature of its asset management strategy, this report contains a number of recommendations identifying specific types of data to be collected for the asset classes examined.

In recognition of ERTH's current efforts to define its AM strategy, this report also provides a set of recommendations for advanced AM metrics that the utility can choose to deploy to derive additional managerial insights from the data collected in the field. We provide our recommendations solely for the purposes of helping the utility consider the range of approaches to advancing its AM capabilities and expect that ERTH will exercise its discretion as to their suitability based on careful consideration of their value proposition relative to the opportunity cost of other strategic initiatives.

2. Asset Condition Assessments as Inputs into Broader Asset Management Planning

2.1. Evidence-Based Asset Management for Distribution Utilities

At its core, the discipline of AM helps organizations derive optimal economic value from their existing and contemplated capital investments in a financially sound and responsible manner. Like modern organizations in other asset-intensive sectors, electric utilities face numerous pressures and opportunities to invest their invariably scarce resources into projects that generate the greatest amount of value for their shareholders and customers. While several potential reference points exist that an organization can choose as a benchmark for structuring its AM processes, there is a general consensus in the electricity transmission and distribution sector that the methodology most suitable for the sector's needs is articulated in the ISO 5500x group of standards (which includes Standards 55000, 55001 and 55002). The core purpose of these standards is the establishment, utilization, and continuous enhancement of AM systems.

An AM System is a group of activities that integrate the collection of asset information and its application to asset planning and investment decision-making process. AM Systems enable utilities to prolong the operating lives and good performance of their assets in a manner that optimizes both short-term and long-term costs while maximizing other objectives valued by the organization and its key stakeholders including safety, environment, reputation, affordability, and others. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM System;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous Improvement stage - those looking to assess and progressively enhance an AM System already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organization can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.

Since it involves the allocation of inherently scarce resources, modern utility AM is about making informed and explicit trade-offs, supported by data that objectively evaluates the necessity and urgency of a given investment – be it in and of itself, relative to other investments, or no investment taking place at all. Key sources of supporting data for an electric utility can take many forms, and typically include:

- Information on the current state of the assets across the service territory:
  - Physical condition of equipment (e.g., wear/tear, natural degradation, etc.);
  - Equipment demographic data (age, manufacturer, material, location); and
  - Manner and extent of equipment's utilization (e.g., average loading vs. top capacity).
- Data on the likelihood of events that an investment seeks to prevent, or bring about:
  - Information on past failure occurrences (how, when, where);
  - Results of statistical analysis of the underlying causes of failures (why); and
  - Past trends of actualized demand growth and known future development plans.
- Data on impact (value gains or losses) of events that investments seek to prevent or facilitate:
  - Cost of potential repairs if an asset fails unexpectedly;
  - Costs sustained by customers due to loss of supply;
  - Safety costs of potential injuries to employees and public, or environmental costs; and
  - Presence of redundancies and other capabilities to mitigate any negative impact.

2.1.1. Key Analytical Inputs into Asset Management Systems and Strategies

An effective AM System entails a constant feedback loop, where results of operations are analyzed against the original planning assumptions and past results, enabling adjustments to strategy and analytical tools. This feedback loop provides organizations with inputs for the development of near-term, and longer-term AM Plans, Policies, or Strategies. These formal (and usually ever-green) documents articulate the manner in which a utility will utilize its AM Systems to achieve its AM objectives, such as liquidation of known equipment deficiencies, compliance with new requirements, improvement of performance levels, integration of new load, and many others. As Figure 3 illustrates, AM Systems, Plans, and Strategies must balance multiple forms of Inputs (performance data, stakeholder preferences, etc.) and Constraints (funding availability, regulatory requirements, etc.) to achieve their stated objectives.

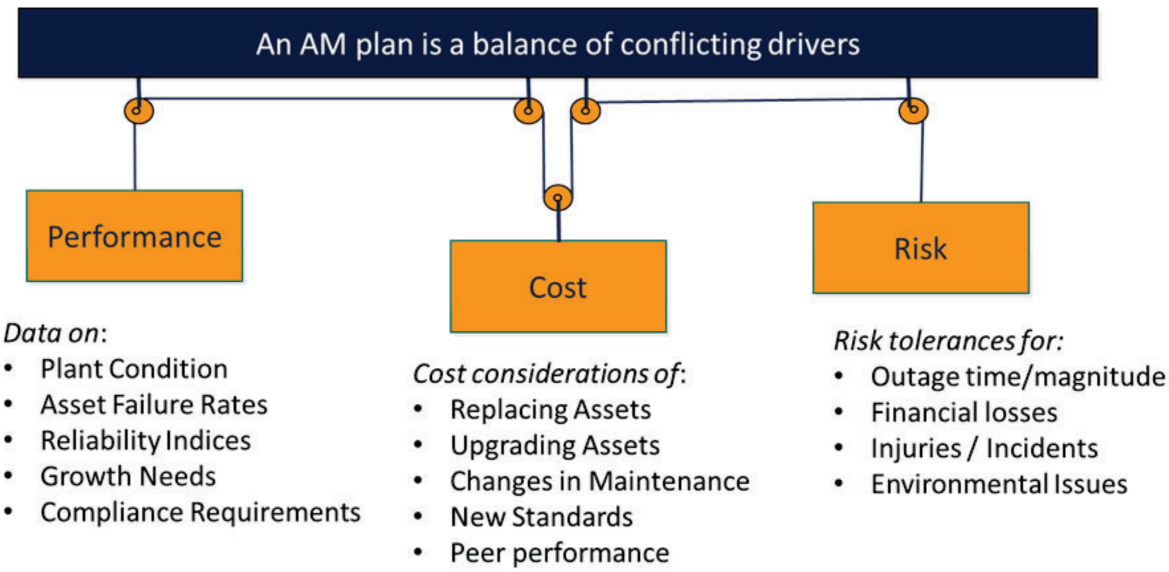

Figure 3: Key AM Plan Inputs and Considerations

While most of these inputs, drivers, and constraints have existed for as long as utilities have been in business, the way in which utilities articulate, analyze, and reconcile these factors is undergoing significant changes in line with the continued development of engineering and economic science. The knowledge and experience of utility subject matter experts continue to play an important role in the development of AM plans. However, technology is changing the customer and regulator expectations as to how (the inevitably subjective) judgment of experts can be supported by objective assessment and prediction of the likelihood, impact, and cost of events that AM plans seek to prevent or bring about.

As can be gleaned from the above discussion of information sources and constraints, an organization's decision to conduct an ACA position it to collect and leverage the information consistent with the first of the three major types of AM decision-making inputs categorized in section 2.1. An ACA is often the first step in establishing (or executing – if already established) a utility's broader AM System – an overall organizational approach to making decisions associated with the continued extraction of value from the assets at its disposal to achieve its core objectives. Underlying any AM System are transparent and evidence-based tools and principles that seek to maximize the expected value of investments over their lifetimes.

2.1.2. Asset Condition Assessments as Long-Term Value Drivers

An ACA is most often thought of as a snapshot in time of the health of a utility's asset base, and by extension, the inputs into planning for addressing its short-term and medium-term intervention needs. Yet, when utilized to its fullest potential, an ACA can yield several other useful insights to asset planners, including:

- The degree to which the current pace of asset interventions (i.e., maintenance, replacement, refurbishment activities) is contributing (positively or negatively) to the overall scope and magnitude of risks managed by the organization;
- The anticipated pace of asset degradation in the future and the ensuing opportunities for making intelligent trade-offs (i.e., by accepting the risks of further degradation on some assets or parts of the system while proactively intervening in others);
- The relationship between the observed/calculated asset degradation parameters and the assets' propensity for failure or misoperation in a manner that the organization deems to be unacceptable (i.e., by tracking and constructing condition-based failure curves);
- The cost-benefit trade-offs of any potential changes to the mix of capital vs maintenance work that a utility may wish to implement to manage its total expenditures, (e.g., deploying labour-minimizing online sensor technology while reducing manual testing);
- The approximate magnitude of capital expenditures that the utility may need to plan to undertake over the longer-term (i.e., when the ACA results are presented in the form of financial metrics, such as replacement cost-weighted condition grade distribution);
- The magnitude of operating expenses and the sequencing/prioritization of ensuing activities to enhance the utility's overall AM framework, as gleaned from the identified asset Data Availability Index ("DAI") and/or other recommendations; and
- The scope and functionalities of advanced AM Information or Operational Technology investments are contemplated as a part of strategic discussions towards the digitization of utility operations.

The above list of potential insights is neither exhaustive nor wholly applicable to ERTH's current state of operations or its strategic priorities. Instead, we present this list as an important reminder that utilities should see the ACA documents as organizational assets in and of themselves – insofar as they represent monetary investments to obtain an objective reading of the state of an organization's core assets. Beyond explicitly informing asset intervention plans, ACAs can act as critical objective inputs into a range of decisions that inherently involve value-based judgment on the part of decision-makers.

3. Asset Health Index Calculation Methodology

ACA is the process of determining an HI, which is a quantitative expression of an asset's current condition. A brand-new asset should have an HI of 100% and an asset in very poor health should have an HI below 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 2 presents the HI ranges and the corresponding asset condition.

Table 2: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of 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 the unit's 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	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on the assessment

3.1. Degradation factors

Degradation factors of the asset are characteristic properties that are used to derive the overall HI. Degradation factors are specific to each asset class. A degradation factor can be comprised of many sub-degradation factors. For example, the oil quality ("OQ") degradation factor of an asset belonging to the station power transformer class includes multiple sub-degradation factors such as acid number, interfacial tension, dielectric strength, and water content.

To determine the overall HI for an asset, formulations are developed based on degradation factors that can be expected to contribute to the degradation and eventual failure of that particular asset type. A weight is assigned to each degradation factor to indicate the amount of influence the condition has on the overall health of the asset. Figure 4 provides an example of an HI formulation table.

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Figure 4: HI Formulation Components

The scale used to determine an asset's score for a degradation factor is called the Degradation factor. Each degradation factor is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a Degradation factor of 4 represents the best grade, whereas a Degradation factor of 0 represents the worst grade. In some cases where there are multiple sub-degradation factors contributing to a single degradation factor, the lowest sub- Degradation factor is taken as the overall Degradation factor for that parameter. This prevents deficiencies in an asset's health from being covered up by averaging processes during the HI calculation.

The conversion from alphabetic ranking to numerical grade and a brief character description of the grade is provided in Table 3.

Table 3: Sample Letter - Numerical Conversion Chart

Letter/Number Grade	Grade Description
A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

3.1.1. Final Asset Health Index Formulation

The final HI, which is a function of the Degradation factors and weights, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} W_i * CI_i}{CI_{max.}}\right) \times 100\%$$

where:

- i corresponds to the degradation factor number within the HI formulation;
- CIi represents the Degradation factor as determined from the testing or field-inspection procedure that is associated with degradation factor i;
- Wi represents the relative importance of degradation factor i within the HI based on the impact of the parameter on the asset's overall failure probability;
- CImax represents the highest numerical grade that can be assigned to the asset and is being used to normalize the final HI score between 0 and 100; and
- HI represents the asset health index as a percentage.

3.1.2. Asset Health Index Results

An asset's HI is given as a percentage; the HI is calculated only if sufficient degradation factor data for a given asset is available. The subset of the total population with sufficient data parameters is called the sample size. HI results can be analyzed on a per-asset, per-asset-class, or per-system basis depending on the granularity required in the analysis.

3.2. Data Sources

To assess the condition of ERTH's stations and distribution systems, BBA was provided with available asset inspection and maintenance data for the asset classes in scope. The data provided included asset registries, visual inspection records, and testing records. Most of this data came from primary sources such as equipment inspection forms completed by ERTH staff or by third parties.

3.2.1. Data Availability Index

The Data Availability Index ("DAI") is a measure of the availability of degradation factor data for a specific asset, as they pertain to the construction of the HI score. The DAI is determined by comparing the sum of the weights of the degradation factors available to the total weight of the degradation factors used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} W_i * \alpha_i}{\sum_{i=1} W_i}\right) \times 100\%$$

where:

- i iterates through the degradation factors within the HI formulation;
- Wi is the weight assigned to degradation factor i;
- ai represents the data availability coefficient, which is equal to 1 if data is available, and equal to 0 when data is unavailable; and
- DAI represents the Data Availability Index as a percentage.

An asset with all degradation factor data available will have a DAI value of 100% independent of the asset's HI score. Assets with a higher DAI will correlate to HI scores with a higher degree of confidence.

3.2.2. Data Gaps

The HI formulations calculated in this study are based only on available data provided by ERTH. In almost all instances, additional degradation factors or tests exist that can be performed on an asset to further ascertain its state of degradation. In certain cases, degradation factors may be available for one or several assets in a class, but unavailable for others in the same class. This scenario represents a data gap, wherein the planner must determine whether the number of assets for which a particular parameter is available is sufficient to include it in the calculation of the overall HI.

An asset with all degradation factor data available will have a DAI value of 100%, independent of that asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For all asset classes, the DAI threshold is 70%. Where missing data are assumed to be infrequent and random, the HI may be extrapolated across the asset category, and in other cases, the data may be flagged for collection.

3.1. HI Extrapolation Methodology

HI was extrapolated by ten-year age-bands. Based on the distribution of assets with Valid His in that ten-year age band, the condition of assets with Invalid HIs can be estimated. In cases where both age is unknown and the HI is invalid, the extrapolation is done based on the full set of assets with known HI scores instead of using ten-year age bands.

3.2. Use of Age as a Degradation factor

There is a degree of debate within the electrical utility industry regarding the appropriateness of including age as a degradation factor for calculating asset Health Indices. At the core of the argument against the use of age in assessing asset condition is the notion that age implies a linear degradation path for an asset that does not always match the experience in the field.

While some assets lose their structural integrity faster than would be expected with time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, BBA attempts to limit the instances where it relies on age as a parameter explicitly incorporated into the calculation of asset HI. In some cases, however, the limited number of degradation factors available for the calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing the condition of complex equipment (e.g., power transformers) – which contain a number of internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing – age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

In the context of the current study, the availability of data on degradation factors varied significantly across asset classes. Where BBA deemed the number of available degradation factors as insufficient to calculate a reliable HI for a particular asset class, and especially where the available information amounted to factors that do not represent the most significant degradation factors for a particular type of equipment, we included age as one of the degradation factors where nameplate data was available.

4. Asset Condition Assessment Results

This section presents the current HI formulation for each asset class, the calculated HI scores, and the data available to perform the study.

For most of the assets, an HI was developed based on industry best practices and then modified based on a reasonable expectation of data availability. In some cases, only demographic information is given because condition data is not available. In other cases, the only data available is demographic (age) data taken from the asset registry along with the results of visual field inspections. While two data points are not sufficient for a rigorous HI (which requires a minimum of three input parameters to qualify as a full HI), the availability of some condition data is significantly better than none.

In these cases, the comment is made that a two-parameter assessment was conducted. For the sake of consistency in reviewing the study's results, however, all of our findings are presented in the same visual distribution format – separating assets into five condition bands between "Very Poor" and "Very Good" with the sixth category of "Invalid HI" to identify the number of assets where data availability was insufficient to meet the threshold. Where missing data are assumed to be infrequent and random, the HI may be extrapolated across the asset category. Ideally, for extrapolation to be carried out for an asset class, a minimum of 40 known values per age band is usually required which is based on a 95% data confidence interval.

Table 4 and Figure 5 present the results of our ACA study in numerical and graphical formats, respectively.

Table 4: System-wide Summary Results

Asset Category	Population	Health Index Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Wood Poles	9273	46%	19%	17%	5%	2%	11%	88%
Concrete Poles	75	51%	17%	1%	4%	25%	1%	78%
Steel Poles	232	0%	42%	11%	3%	3%	41%	49%
Underground Cables	167 (km)	60%	20%	6%	7%	1%	5%	96%

Asset Category	Population	Health Index Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Switchgears	10	90%	10%	0%	0%	0%	0%	100%
Junction Boxes	120	88%	11%	2%	0%	0%	0%	83%
Pole Mount Transformers	1618	85%	6%	9%	0%	0%	0%	81%
Pad Mount Transformers	1134	51%	16%	21%	1%	0%	12%	94%
Overhead Load Break Switches	69	57%	4%	0%	0%	0%	39%	52%
Station Power Transformers	11	9%	55%	36%	0%	0%	0%	88%

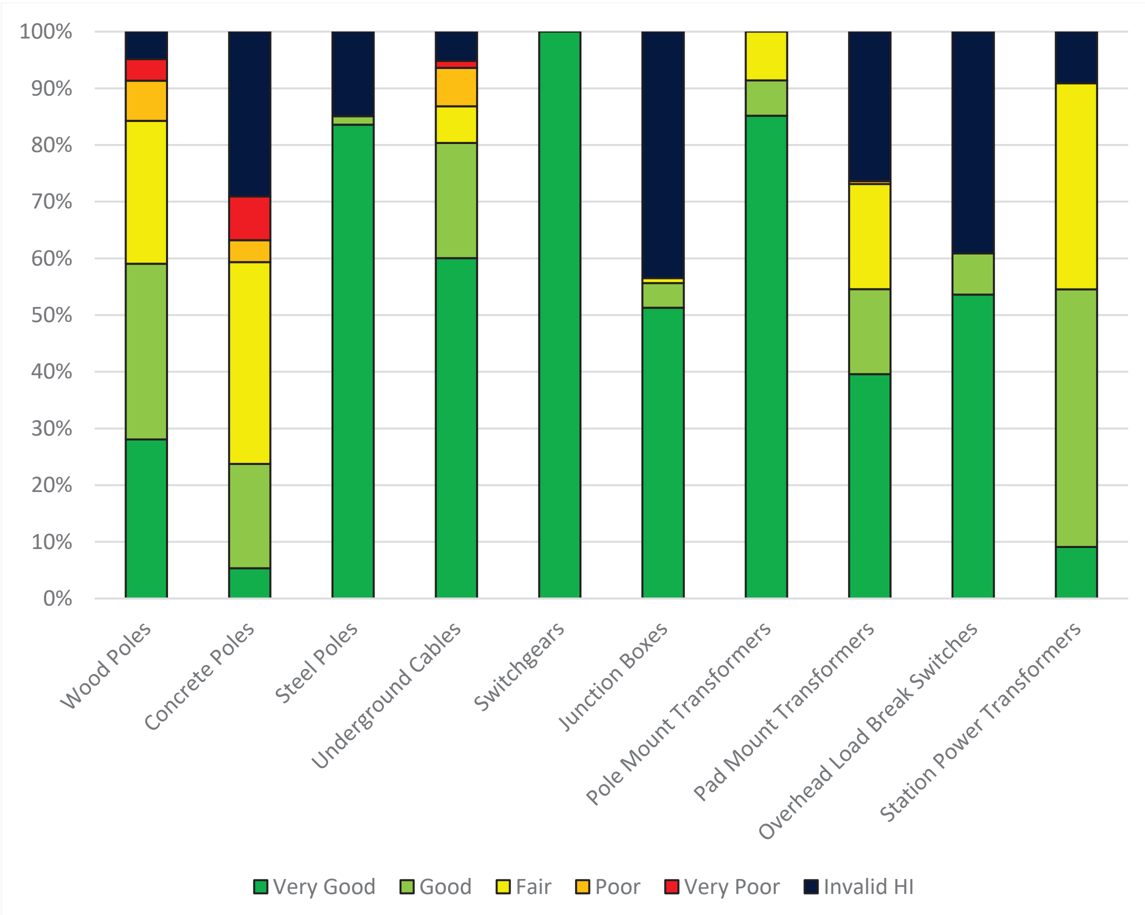

Figure 5: System-wide Summary Results

As the above results indicate, the vast majority of ERTH's assets are in a Good condition or better, with relatively minor portions of assets receiving Poor or Very Poor grades. As such, the results are indicative of a relatively healthy system – with no signs of material deterioration consistent with poor AM practices. The extrapolated system-wide summary results can be seen in Figure 6 and extrapolations for each asset class can be found within its section.

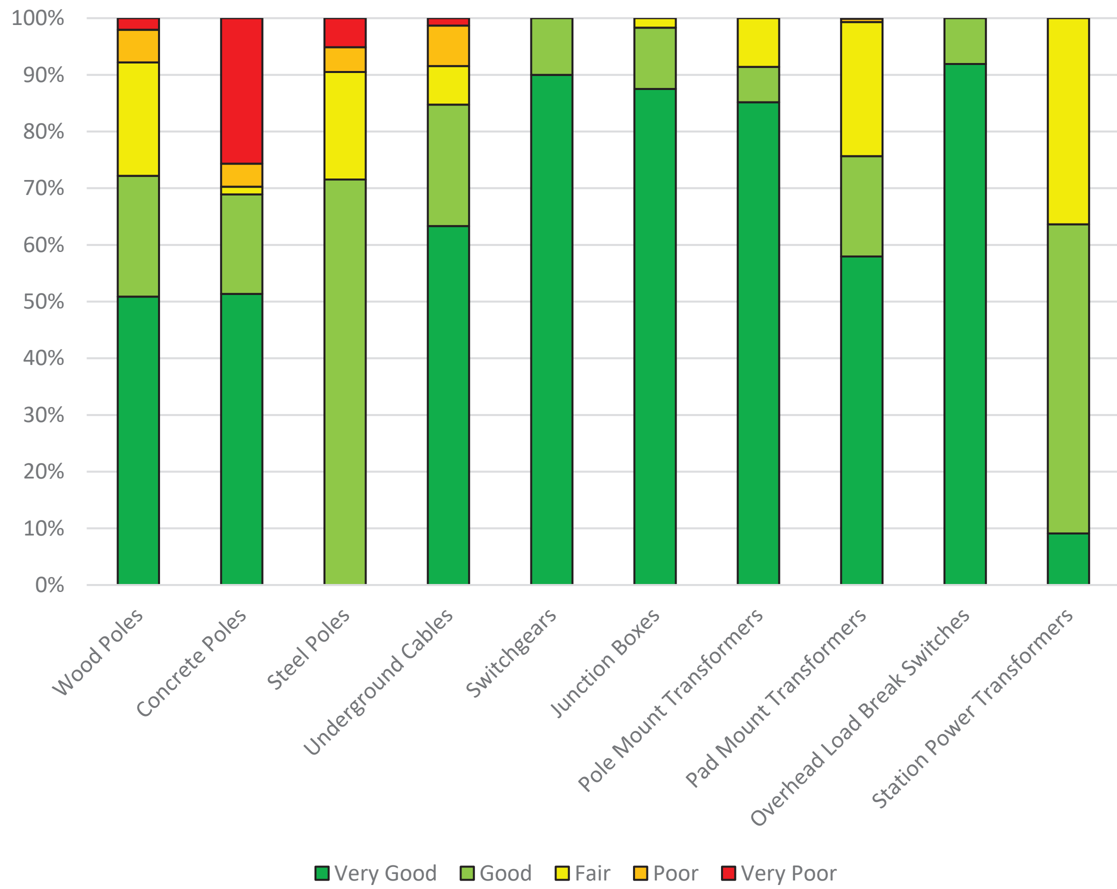

Figure 6: Extrapolated System-wide Summary Results

Being a relatively new entity, ERTH is still in the process of defining its long-term AM strategy and refining its data collection and storage processes. As it continues to evolve, we expect it to revisit the scope and nature of data collection practices across its asset classes using the recommendations contained in the remainder of this report.

4.1. Distribution Assets

4.1.1. Wood Poles

4.1.1.1. Condition Assessment Methodology

Wood poles are the most common asset owned by an electrical utility and are an integral part of the distribution system. Poles are the support structure for overhead distribution lines as well as assets such as overhead transformers, switches, and reclosers.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation processes for wood poles involve biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather which can impact the mechanical strength of the pole. Loss in the strength of the pole can present additional safety and environmental risks to the public and the utility.

In the short term the most informative end-of-life criterion is the calculation of remaining strength through pole testing. However, since pole strength tends to fall off quickly as a pole starts to degrade, the preferred predictor over the medium to long term is age. Generally, poles that are newer than ten years in service are not tested at all and are assumed to be in Very Good condition.

The HI for wood poles is calculated based on end-of-life criteria summarized in Table 5. Appendix A.1 provides grading tables for each degradation factor.

Table 5: Wood Pole HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Overall Condition	1	A,B,C,D,E	4,3,2,1,0	4
Wood Rot	1	A,B,C,D,E	4,3,2,1,0	4
Remaining Strength	5	A,B,C,D,E	4,3,2,1,0	20
Total Score				40

4.1.1.2. Data Collection and Assumptions

Wood poles are visually inspected and tested by an approved pole testing contract service on a nine-year cycle or as needed.

Where conflicting data for age existed between the asset registry and the field notes, the field notes information was used for analysis.

A number of assumptions were made to process the raw data files. Strength testing is not conducted for newer poles (9 years in service or less). For these poles, the remaining strength is assumed to be 100 percent. Where poles are known to have been visually inspected, and there are no notes given about poles leaning, or exhibiting rot, these poles are assessed and given a grade of 'A' for the respective data fields. If the pole is not known to have been inspected, these assumptions are not made.

The average DAI for wood poles across ERTH's distribution system is 88%.

4.1.1.3. Demographics

ERTH owns 9,273 wood poles within its service territory. Service age is unknown for approximately 1% of the total in-service population. Figure 7 presents the age distribution for in-service wood poles.

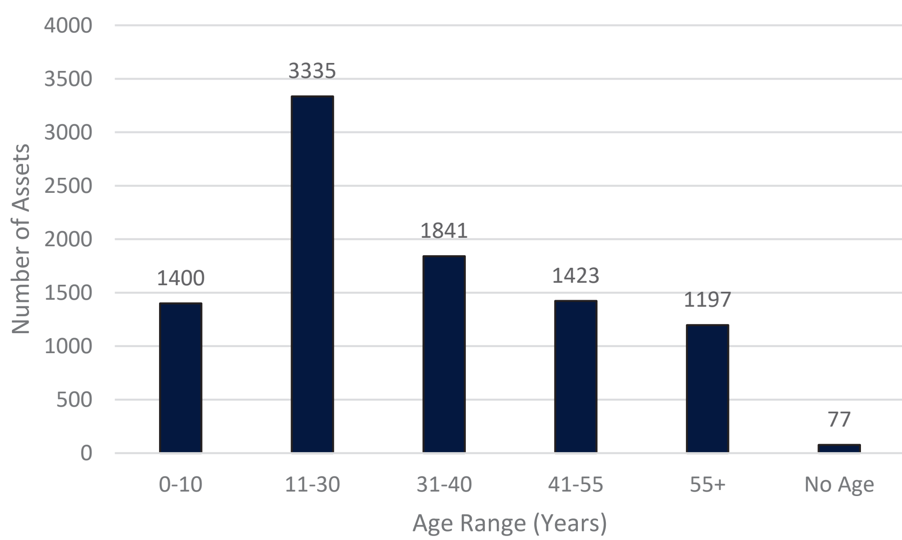

Figure 7: Wood Pole Age Distribution

4.1.1.4. HI Results

The overall HI distribution is presented in Figure 8. A valid HI was calculated for 89% of the wood poles.

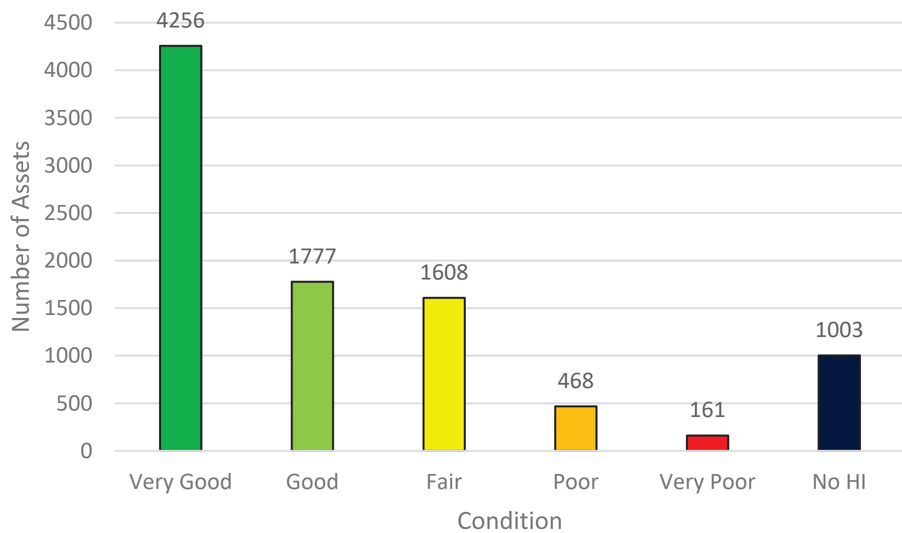

Figure 8: Wood Pole HI Results

4.1.1.5. Extrapolated Results

The extrapolated HI distribution is presented in Figure 9.

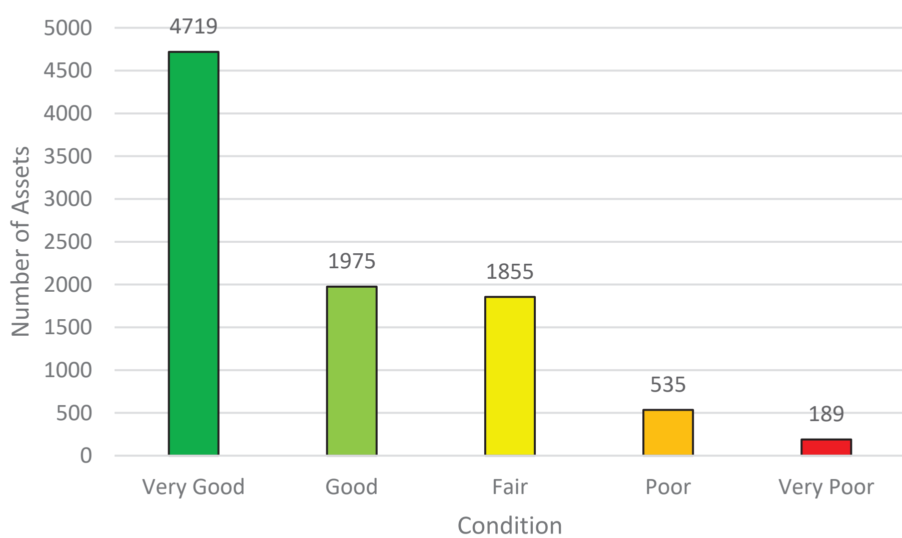

Figure 9: Extrapolated Wood Pole HI Results

4.1.2. Concrete Poles

4.1.2.1. Condition Assessment Methodology

Concrete poles have a similar use as wood poles in the distribution system with the exception that concrete poles are often used for specific applications such as downtown core areas, or improved appearance applications.

Concrete poles have a different degradation mechanism than wood poles. There is no practical "pole test" for concrete poles, but since poles are hollow, there are also limited opportunities for invisible degradation and interior rot. Concrete poles develop corrosion on the internal reinforcing bars, which expands the iron and displaces the concrete in a process known as spalling. Once spalling begins, poles become weaker and tend to fail over a short number of years. There are limited methods for the long-term repair of a spalled pole. Spalling is accelerated in the presence of road salt. In the short term (one to three years) the most informative indicator is a visual observation of spalling; there is no way to predict that corrosion is occurring inside concrete poles. The best predictor of a need for medium-term replacement (three to ten years) is the age and condition of similar poles.

Table 6Table 7 below provides the concrete pole HI algorithm. Additional details about these degradation factors and how they are graded can be found in Appendix A.2.

Table 6: Concrete Pole HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	7	A,B,C,D,E	4,3,2,1,0	28
Visual Inspection	3	A,C,E	4,2,0	12
Total Score				40

4.1.2.2. Data Collection and Assumptions

Approximately 99% of the in-service concrete poles have age values but a large number of poles (69%) lacks inspection data so the average DAI for concrete poles is 78%.

4.1.2.3. Demographics

ERTH owns 75 concrete poles, of which 1 does not have age data. Figure 10 presents the age distribution for in-service concrete poles.

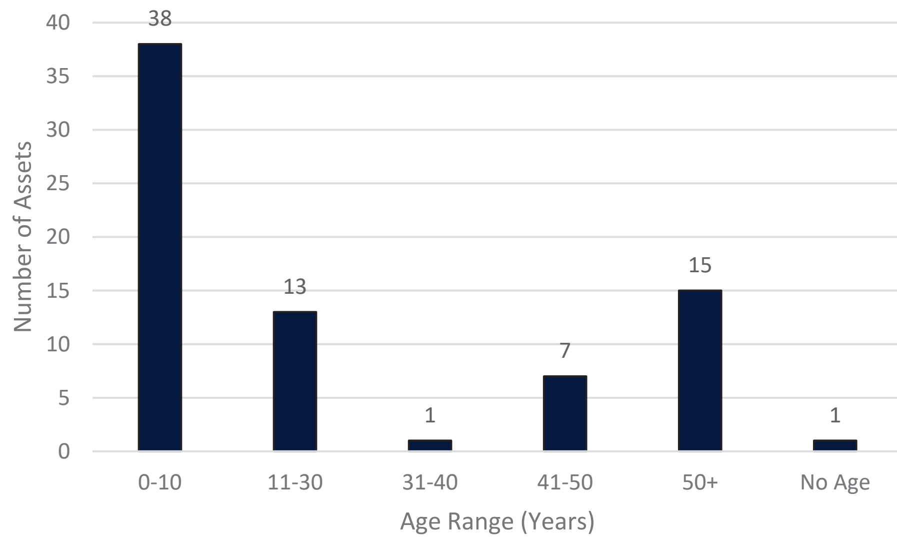

Figure 10: Concrete Pole Age Distribution

4.1.2.4. HI Results

For this asset class, a two-parameter assessment was conducted. The overall HI distribution for concrete poles is presented in Figure 11. Most of the known poles are in Poor or Very Good condition.

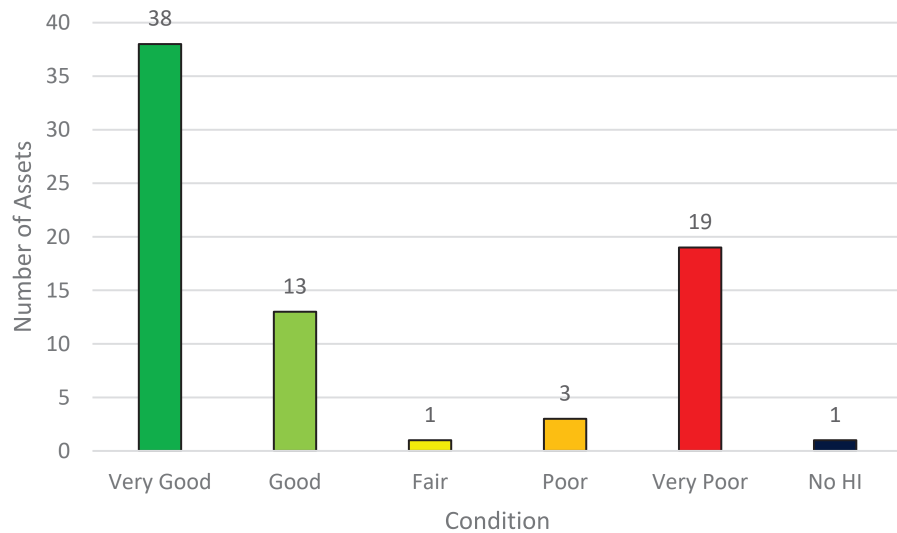

Figure 11: Concrete Pole HI Results

4.1.2.5. Extrapolated Results

The extrapolated HI distribution is presented in Figure 12.

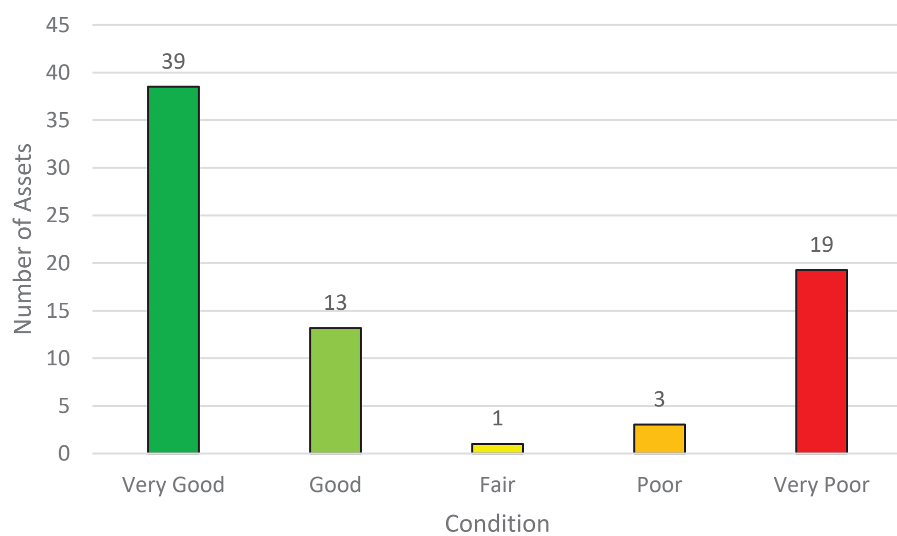

Figure 12: Extrapolated Concrete Pole HI Results

4.1.3. Steel Poles

4.1.3.1. Condition Assessment Methodology

Steel poles serve a comparable role to wood poles in distribution systems, though they are often chosen for specialized applications such as urban areas or for aesthetic improvements.

Unlike wood poles, steel poles degrade differently. There isn't a practical "pole test" for steel poles, but they are susceptible to corrosion. Corrosion weakens the structural integrity of steel poles, leading to potential failure over time. Environmental factors like exposure to moisture, chemicals, or saline environments can accelerate corrosion.

Steel poles may exhibit signs of corrosion such as rust or pitting, which can weaken the pole and compromise its load-bearing capacity. Regular visual inspections are essential to identify signs of corrosion and assess the condition of steel poles.

In cases where corrosion has significantly compromised the integrity of a steel pole, there may be limited options for long-term repair. Replacement becomes necessary to ensure the reliability and safety of the distribution system. While steel poles offer durability and strength, proactive maintenance and timely replacement are essential to mitigate the risks associated with corrosion and ensure the continued reliability of the utility infrastructure.

Table 7 below provides the steel pole HI algorithm. Additional details about these degradation factors and how they are graded can be found in Appendix A.3.

Table 7: Steel Pole HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	7	A,B,C,D,E	4,3,2,1,0	16
Visual Inspection	3	A,C,E	4,2,0	24
Total Score				40

4.1.3.2. Data Collection and Assumptions

Approximately 59% of the in-service steel poles have age values and 27% have inspection data and so the average DAI for steel poles is 49%.

4.1.3.3. Demographics

ERTH owns 232 steel poles, of which 95 do not have age data. Figure 13 presents the age distribution for in-service steel poles.

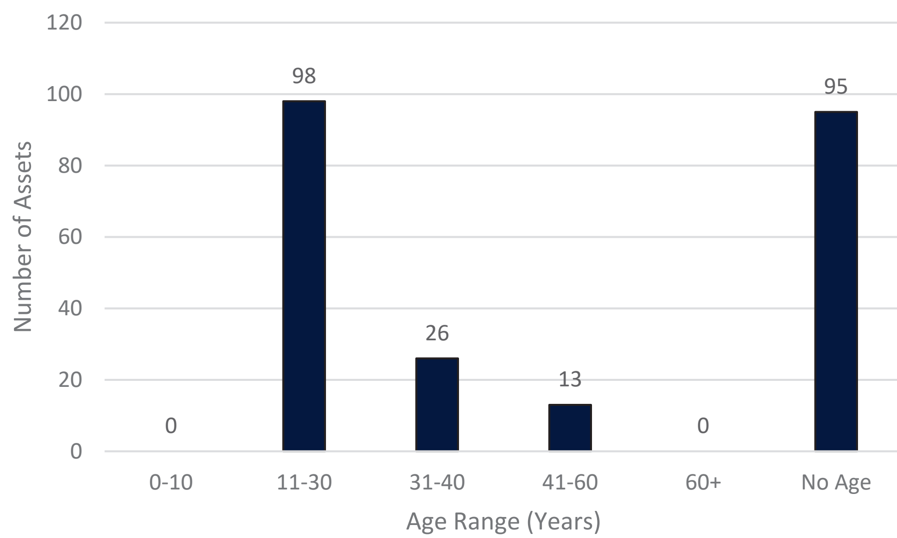

Figure 13: Steel Pole Age Distribution

4.1.3.4. HI Results

For this asset class, a two-parameter assessment was conducted. The overall HI distribution for steel poles is presented in Figure 14. Most of the known poles are in Good condition.

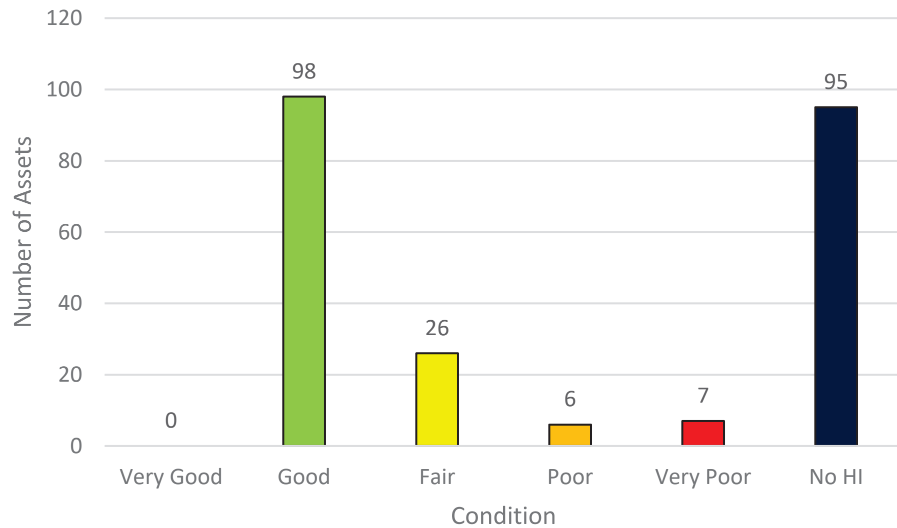

Figure 14: Steel Pole HI Results

4.1.3.5. Extrapolated Results

The extrapolated HI distribution is presented in Figure 15.

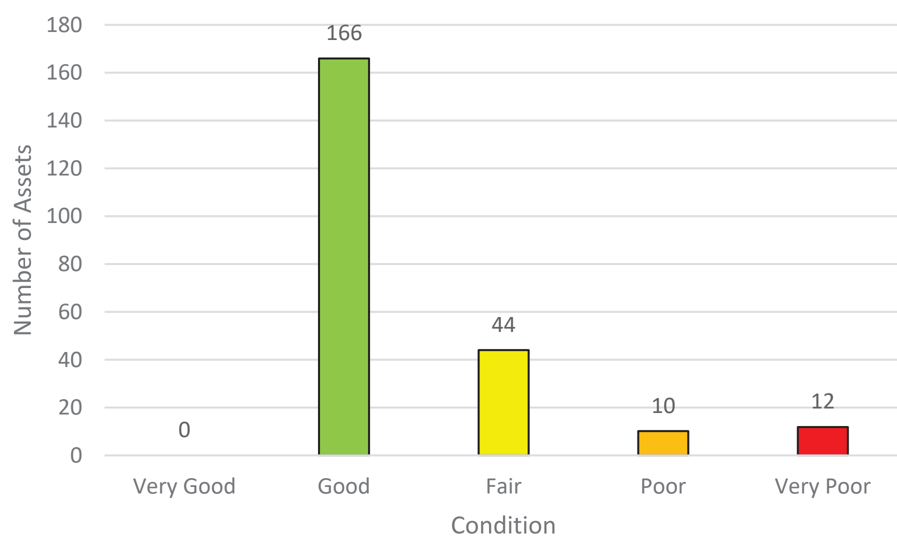

Figure 15: Extrapolated Steel Pole HI Results

4.1.4. Underground Cables

4.1.4.1. Condition Assessment Methodology

Distribution underground primary cables are one of the more challenging assets on electricity systems from a condition assessment and AM viewpoint. Although a number of test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring cable failure rates, peak loading, and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, cables are replaced 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 asset health results for primary underground primary cable in this study are calculated by including service age as a major component.

Service age provides a reasonably good measure of the remaining life of cables with the lack of visual inspection for cable defects. As a minimum, age-based parameters and the knowledge of past failure instances and loading will allow the comparison of a given cable segment to other cables of similar vintage.

Table 8 below provides the HI algorithm for underground cables. Additional details about these degradation factors and their manner of grading can be found in Appendix A.4.

Table 8: Underground Cable HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	6	A,B,C,D,E	4,3,2,1,0	24
Failure Rate	4	A,C,E	4,2,0	16
Loading History	1	A,B,C,D,E	4,2,0	4
Total Score				44

4.1.4.2. Data Collection and Assumptions

Given their below-grade location and the associated access difficulties, information on the condition of underground cables is notoriously difficult and costly to obtain. Data for this asset is limited to records of age, past failures, and loading history.

As insulation material and construction type become important to assessing cable condition through the service age, assumptions have been made to those missing information. When insulation material is unknown, cable sections are assumed to be cross-linked polyethylene (XLPE) insulated. This assumption is made to consider the worst scenario, i.e., the shortest TUL.

The DAI measures the percentage of assets for which the data used in the HI formulation is available. The DAI for the underground cables across all voltages is 96%.

4.1.4.3. Demographics

The ERTH system features underground primary voltage cables with a combined length of approximately 167 km. Age records were not available for approximately 74 km (51%) of ERTH's total underground cable assets. Ages for underground cable assets were extrapolated on a feeder level based on the average age of known cable segments for each feeder. This average age was used to estimate the ages of unknown cable segments in the analysis.

Figure 16 shows the overall age distribution of ERTH's underground cables by length.

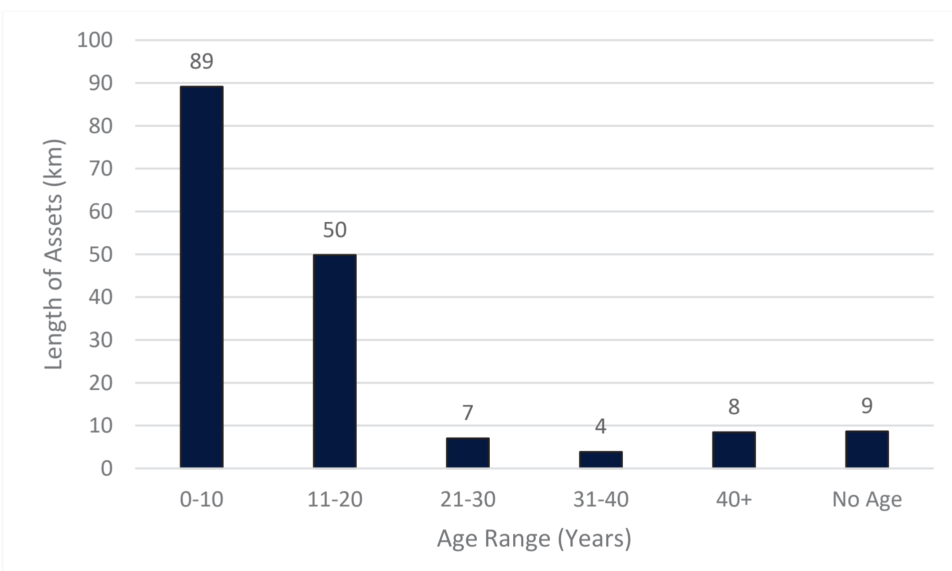

Figure 16: Underground Cable Age Distribution

4.1.4.4. HI Results

Figure 17 provides the HI distribution for underground cables in aggregate. A valid HI was calculated for 95% of underground cables.

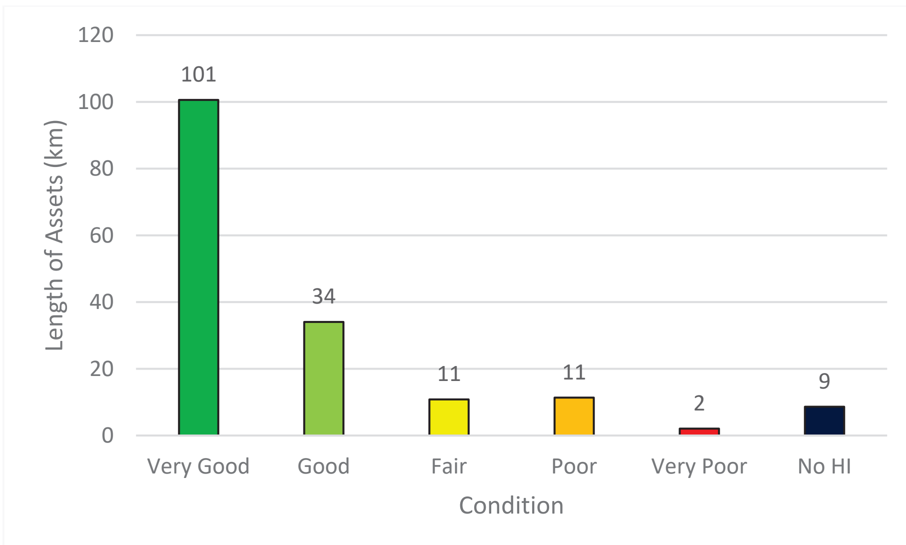

Figure 17: Underground Cable HI Results

4.1.4.5. Extrapolated Results

The extrapolated HI distribution is presented in Figure 18.

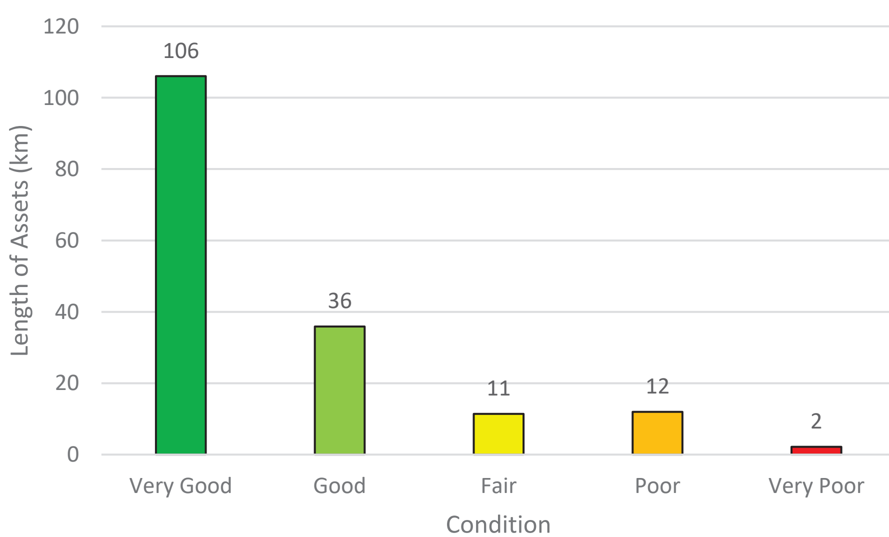

Figure 18: Extrapolated Underground Cable HI Results

4.1.5. Switchgears

4.1.5.1. Condition Assessment Methodology

Switchgear is a major sub-class of the switch asset group. Switchgear can be air-, oil-, or SF6-insulated; can contain fuses or vacuum interrupters and can be operated manually or remotely via automation schemes and SCADA.

Typical end-of-life indicators for pad-mounted switchgear are related to physical deterioration of the enclosure, the internal workings of the switchgear, and in some cases the extent of deterioration to the concrete pad. Preventative maintenance options for switchgear may include the replacement of components such as interphase barriers, arc chutes, and pressure cleaning.

The HI formulation for switchgears typically uses service age, visual inspections, and IR scan results as degradation factors. ERTH's distribution switchgear HI formulation consists of four parameters, with the combination of visual inspection accounting for three-quarters of the total maximum health score. Visual inspection includes the condition of enclosure, barriers, and pad.

Table 9 below provides the HI algorithm for pad-mounted distribution switchgears. Additional details about these degradation factors and how they are graded can be found in Appendix A.5.

Table 9: Pad-Mounted Distribution Switchgear HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Enclosure	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Barriers	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Pad	3	A,C,E	4,2,0	12
				48

4.1.5.2. Data Collection and Assumptions

Inspection results for switchgears are only reported when issues are identified, leading to the assumption that all switchgears are in good condition unless noted.

The DAI for the pad-mounted switchgear is 88%.

4.1.5.3. Demographics

ERTH owns 10 switchgears within its service territory. Figure 19 presents the age distribution for in-service pad-mounted switchgear.

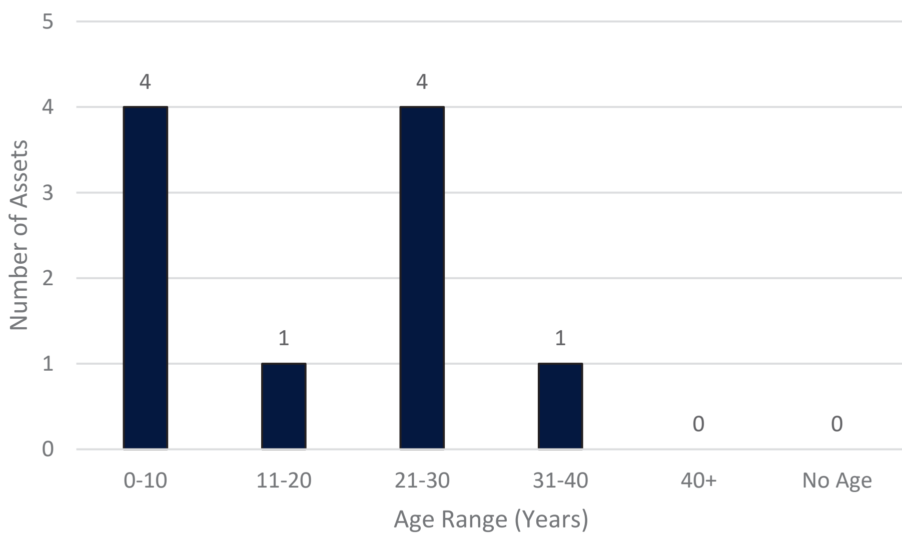

Figure 19: Switchgear Age Distribution

4.1.5.4. HI Results

The overall HI distribution is presented in Figure 20. All but one unit are in Very Good condition.

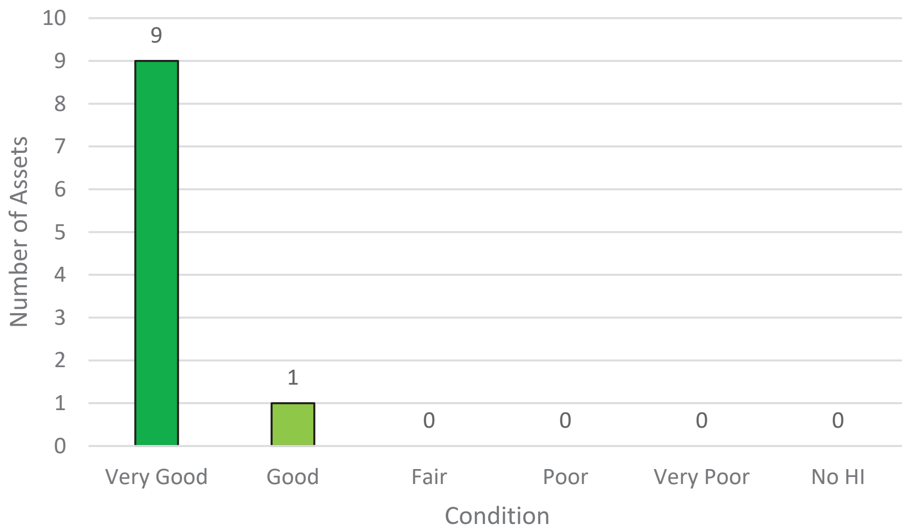

Figure 20: Switchgear HI Results

4.1.6. Junction Boxes

4.1.6.1. Condition Assessment Methodology

Junction boxes provide a protective housing for electrical connections and devices, ensuring safety and reducing the risk of electrical hazards. Junction boxes are commonly installed in residential, commercial, and industrial settings to facilitate splicing or branching of electrical circuits. They serve as a centralized point for connecting multiple wires or cables securely within a single location.

Inspection of junction boxes typically involves assessing the physical condition of the enclosure and internal components to identify signs of deterioration or damage. Maintenance options for junction boxes may include the replacement of components such as gaskets or seals to ensure continued reliability and safety.

Like switchgears, the HI formulation for junction boxes uses service age and visual inspections as degradation factors. The resulting formulation is captured in Table 10. Additional details about the degradation factors above and they are graded can be found in Appendix A.6.

Table 10: Junction Box HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Enclosure	4	A,B,C,D,E	4,3,2,1,0	8
Condition of Pad	4	A,C,E	4,2,0	8
Total Score				40

4.1.6.2. Data Collection and Assumptions

There are 115 junction boxes in the ERTH service area with age data available for 44 (38%). Visual inspection reports are available for 69. Visual inspections are exception based so the default condition of the enclosure and pad are assumed to be Very Good unless reported otherwise.

The DAI for this asset class is 73%.

4.1.6.3. Demographics

The installation date is unknown for approximately 62% of the total in-service population. Figure 21 shows the age distributions for the junction boxes.

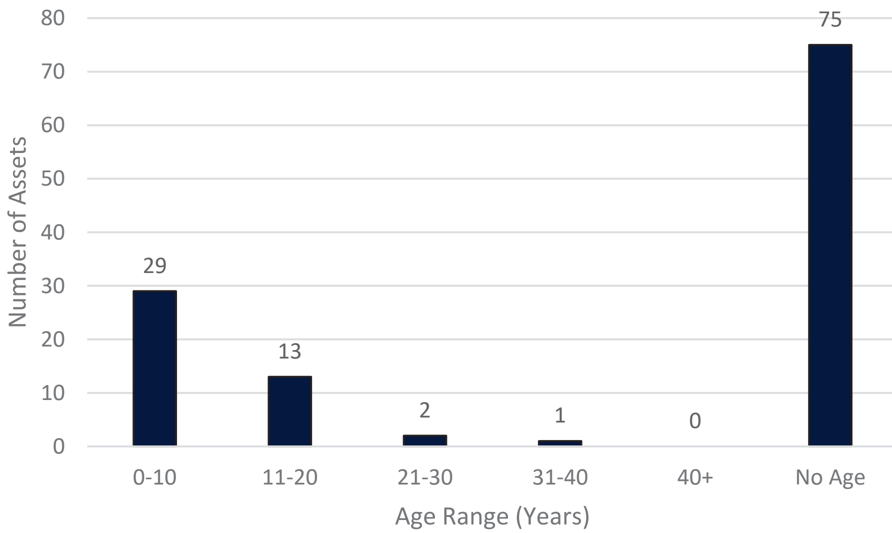

Figure 21: Junction Box Age Distribution

4.1.6.4. HI Results

Figure 22 shows the overall HI of ERTH's in-service junction boxes. The majority of junction boxes are in Very Good condition.

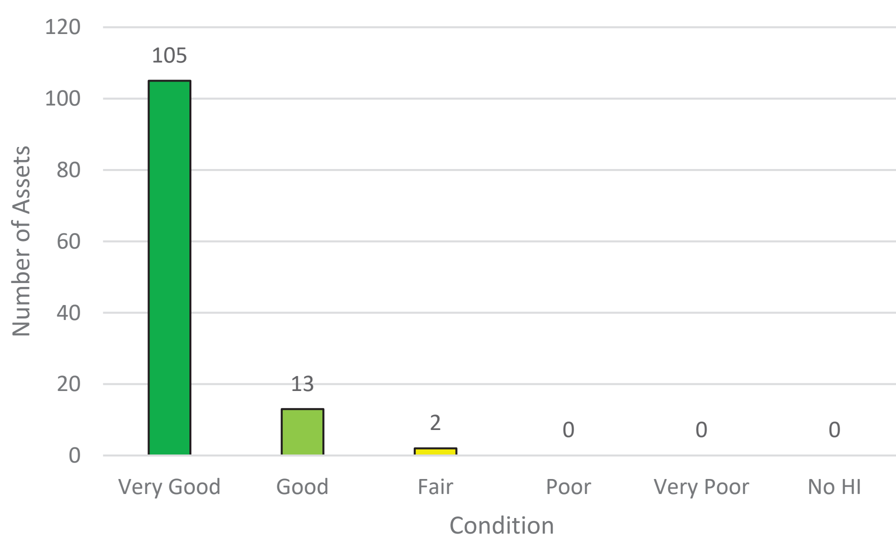

Figure 22: Junction Box HI Results

4.1.7. Pole-Mounted Transformers

4.1.7.1. Condition Assessment Methodology

Pole-mounted transformers are another large asset class within the utility system. This asset category is made up of a large number of units, each with a modest replacement value. Transformers are generally considered to be a run-to-failure asset class with little maintenance other than visual inspections. Transformers may be replaced in planned projects based on identifiable degradation, pole line rebuilds, road relocations, and upgrade projects in response to customer load growth.

Transformers typically reach their end-of-life due to physical tank deterioration such as corrosion, which in extreme cases can lead to an instance of leaking oil. Where corrosion is detected, a transformer may be cycled back to the shop and re-painted with gaskets being replaced. Other modes of failure include overheated connections due to loosened connectors, which are typically detected in infrared scanning and tightened to reduce the failure risk.

Table 11 below the HI algorithm for pole-mounted transformers. Additional details about these degradation factors and how they are graded can be found in Appendix A.7.

Table 11: Pole-Mounted Transformer HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Tank	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Bushing	1	A,B,C,D,E	4,3,2,1,0	4
Infrared Scan	3	A,C,E	4,2,0	12
Oil Leaks	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				40

4.1.7.2. Data Collection and Assumptions

ERTH has about 1,618 pole-mounted transformers. During ERTH's overhead inspections, any issues regarding pole-mounted transformers are immediately reported and rectified. As a result, it is assumed in this analysis that the visual inspection results for pole-mount transformers are Good unless otherwise specified. Infrared scanning was performed on the entire overhead system. Only exceptions are reported so any devices that do not have an infrared report did not have an elevated temperature and are scored 'A' in the Infrared Scanning condition. This was also the case for any Oil Leak inspections.

The DAI for pole-mounted transformers is 81%.

4.1.7.3. Demographics

Approximately 36% (586) of the units (1618) have recorded age data. Figure 23 shows the age distributions for the pole-mounted transformers.

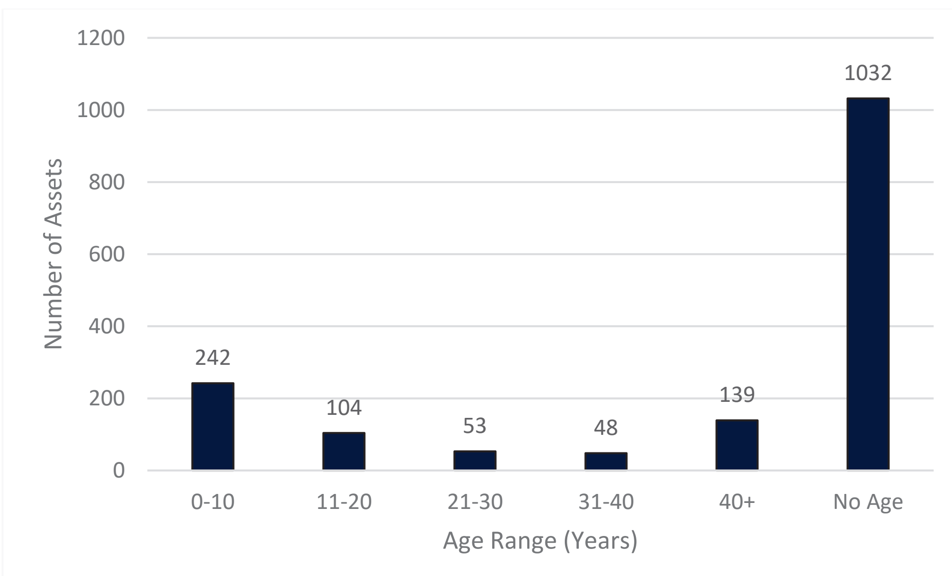

Figure 23: Pole-Mounted Transformer Age Distribution

4.1.7.4. HI Results

The HI for pole-mounted transformer is shown in Figure 24.

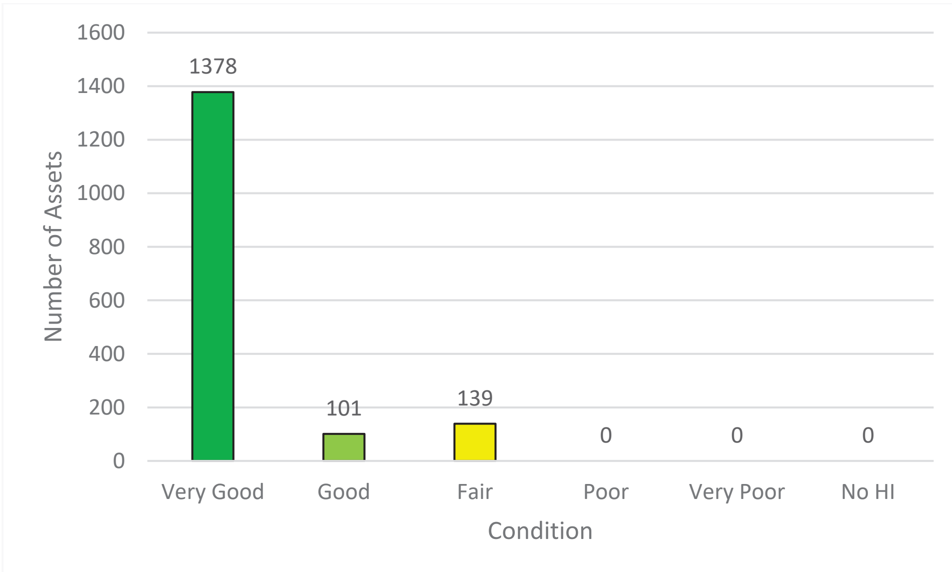

Figure 24: Pole-Mounted Transformer HI Results

4.1.8. Pad-Mounted Transformers

4.1.8.1. Condition Assessment Methodology

Pad-mounted transformers are typically a run-to-failure asset, although transformers may be renewed as part of a planned program. Apart from painting the tanks, replacing damaged bushings, or repairing leaky gaskets, most utilities carry out very little preventative maintenance or testing on distribution transformers.

Transformers typically reach their end-of-life due to physical tank deterioration, such as corrosion which, in extreme cases, can lead to oil leaks. Where corrosion is detected, a transformer may be cycled back to the shop, re-painted, and gaskets can be replaced. Other modes of failure include overheated connections due to loosened connectors which are typically detected in infrared scanning and tightened. Sometimes the deterioration of civil infrastructures such as pads and duct banks contribute to the decision to replace a pad-mounted transformer.

Utilities generally replace pad-mounted transformers during underground rebuild projects or when increases in load patterns develop. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified.

The HI for pad-mounted transformers consists of age and various visual inspections. Age represents a material portion of the overall HI scoring, as it acts as a proxy for the degradation processes affecting the internal workings of transformers that are not visible during visual assessments and are not economical to subject to empirical testing used on station transformers.

Table 12 below provides the HI algorithm for pad-mounted transformers. Additional details about these degradation factors and how they are graded can be found in Appendix A.8.

Table 12: Pad-Mounted Transformer HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Pad	1	A,C,E	4,2,0	4
Oil Leaks	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Enclosure	1	A,C,E	4,2,0	4
Total Score				32

4.1.8.2. Data Collection and Assumptions

Approximately 140 pad-mounted transformers do not have recorded age data, whereas approximately 198 pad-mounted transformers are missing inspection reports. The absence of an inspection report indicates that there is no concern with the pad-mount transformer and is Good condition.

The DAI for pad-mounted transformers is 94%.

4.1.8.3. Demographics

Within ERTH's distribution system, there are 1,134 pad-mounted transformers. The installation date is unknown for approximately 12% of the total in-service population. Figure 25 presents the age distribution for in-service pad-mounted transformers.

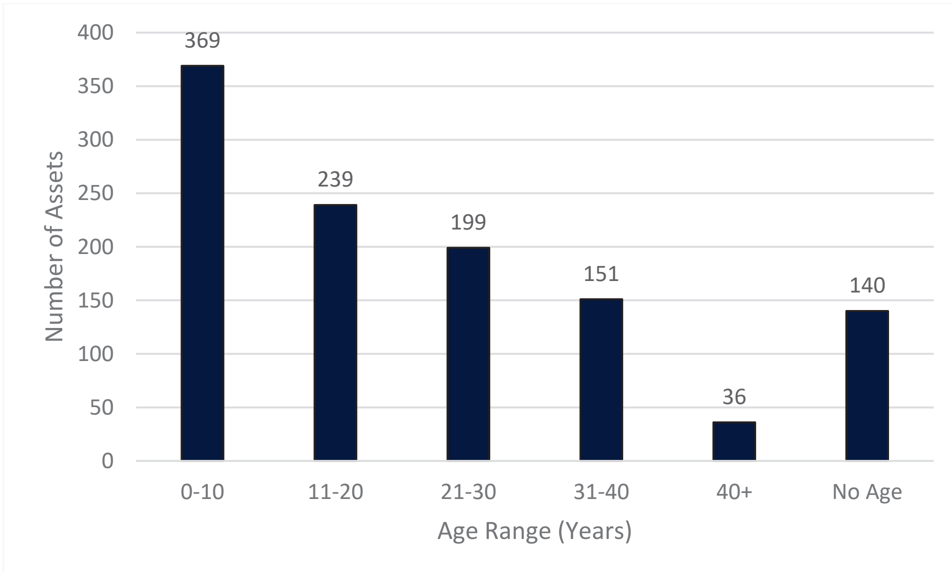

Figure 25: Pad-Mounted Transformer Age Distribution

4.1.8.4. HI Results

The HI results for pad-mounted transformers are shown in Figure 26.

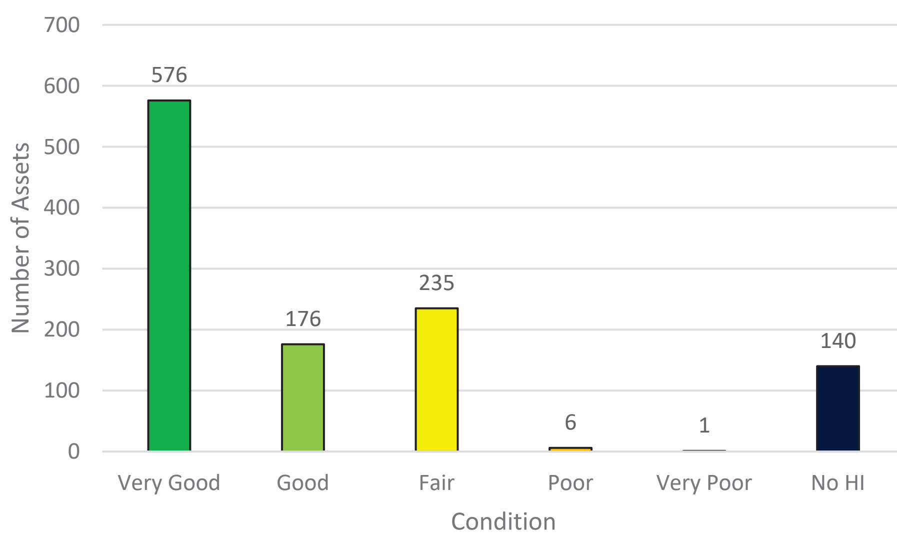

Figure 26: Pad-Mounted Transformer HI Results

4.1.8.5. Extrapolated Results

The extrapolated HI distribution is presented in Figure 27.

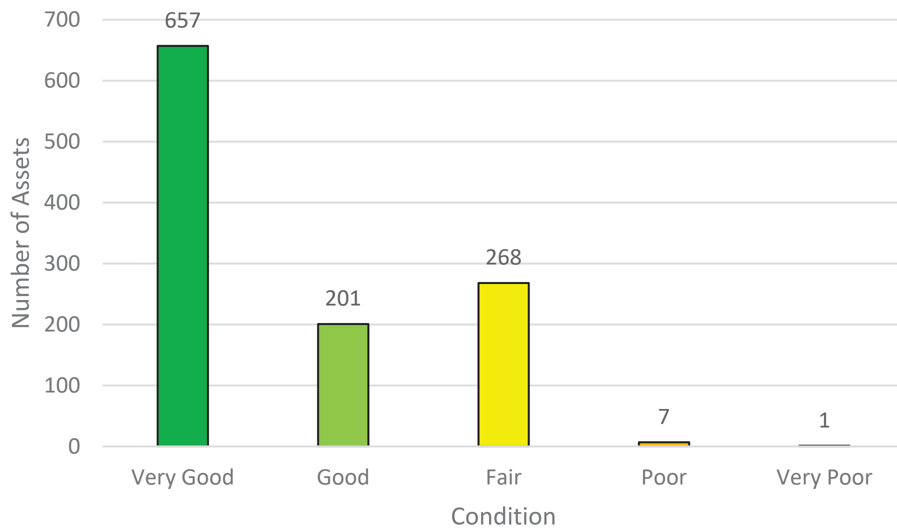

Figure 27: Extrapolated Pad-Mounted Transformer HI Results

4.1.9. Overhead Load Break Switch

4.1.9.1. Condition Assessment Methodology

In many utilities, overhead load break switches are considered to be a part of "line hardware" and are, therefore, not proactively managed. Overhead load break switches provide means of load disconnection and isolation for equipment, such as overhead or underground laterals and services or transformers.

Degradation factors are generally limited to physical corrosion, insulator tracking, and/or heat generated by loose connections. Occasionally a manufacturing defect will result in accelerated loss of life.

The HI formulation for distribution switches typically uses service age, visual inspections, and IR scan results as degradation factors. The resulting formulation is captured Table 13. Additional details about these degradation factors and how they are graded can be found in Appendix A.9.

Table 13: Overhead Load Break Switch HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,C,E	4,2,0	8
Condition of Insulators	1	A,C,E	4,2,0	4
Condition of Operating Mechanism	1	A,C,E	4,2,0	4
Condition of Housing	1	A,C,E	4,2,0	4
IR Scan	3	A,C,E	4,2,0	12
Total Score				32

4.1.9.2. Data Collection and Assumptions

Infrared scanning and visual inspections are performed on the entire overhead system. Approximately 39% of all overhead load break switches are missing visual inspection data.

The DAI for this asset is 52%.

4.1.9.3. Demographics

Approximately 25% of the 69 switches have age data available. Figure 28 shows the age distributions for the in-service overhead load break switches.

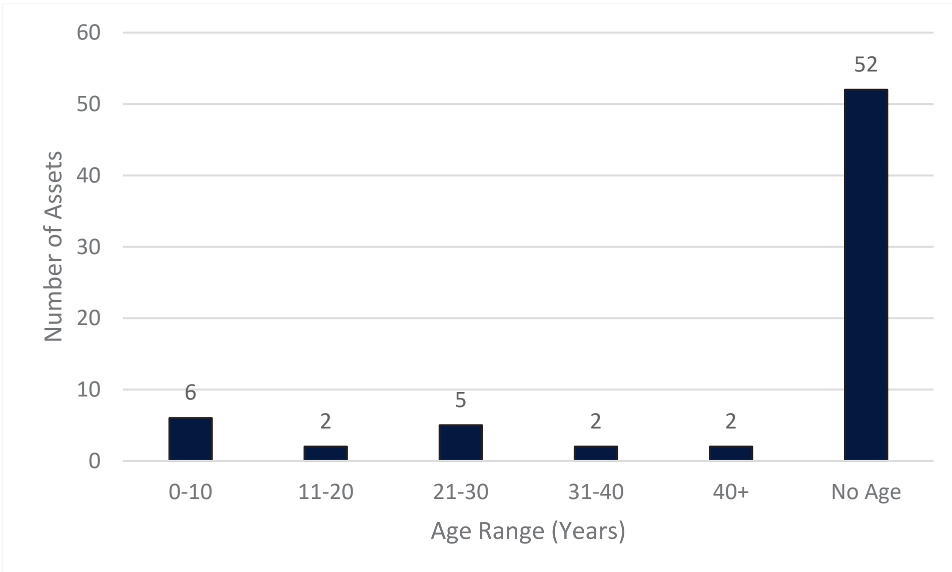

Figure 28: Overhead Load Break Switch Age Distribution

4.1.9.4. HI Results

Figure 29 illustrates the HI results for all overhead load break switches. There is a total of 69 switches, most of which are in Very Good to Good condition except for 27 units do not have a valid HI, largely due to unavailable age and condition data.

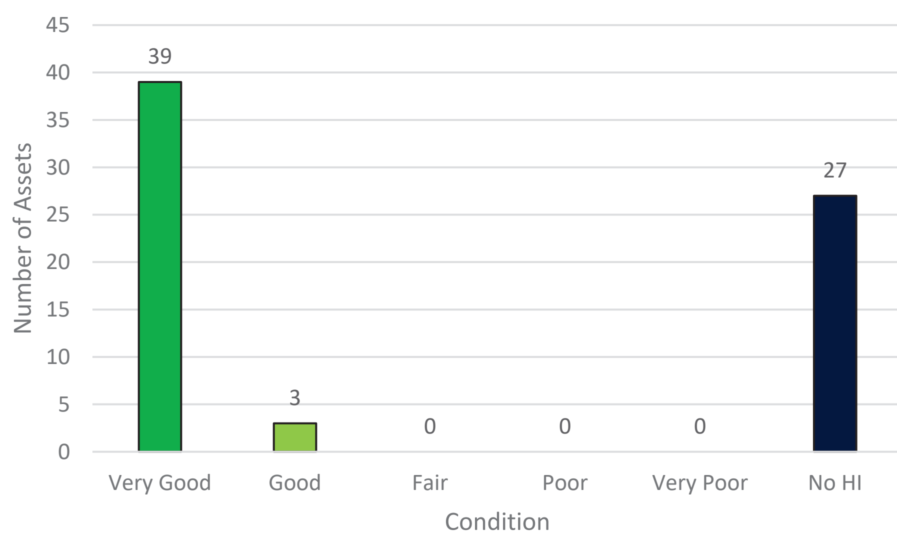

Figure 29: Overhead Load Break Switch HI Results

4.1.9.5. Extrapolated Results

The extrapolated HI distribution is presented in Figure 30.

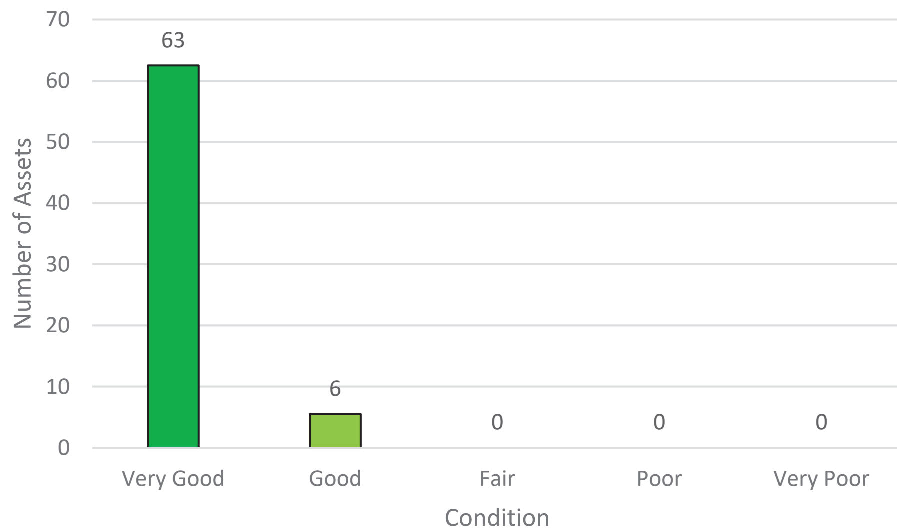

Figure 30: Extrapolated Overhead Load Break Switch HI Results

4.2. Station Assets

This section describes those assets which represent the main station assets of the distribution system.

4.2.1. Station Transformers

4.2.1.1. Condition Assessment Methodology

Station transformers are the single most critical asset class. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect tens of thousands of customers.

Degradation mechanisms include loss of insulation or oil quality due to overload or low-level internal faults causing heating, arcing, and/or physical deterioration such as corrosion or failed cooling systems. Station transformers are the most tested and tracked utility assets and reliable indicators of the impending need for maintenance or replacement include dissolved gas analysis ("DGA"), oil quality ("OQ"), and power factor ("PF") testing. Some tests can be conducted in-service and others required taking the asset out of service. Many features such as cooling fans are external to the tank and can be maintained in situ.

Table 14 provides the HI algorithm for station transformers. Additional details about these degradation factors and how they are graded can be found in Appendix A.10.

The HIF for station power transformers is the most complex of all asset classes assessed. The top key degradation factors indicated in Table 14 are DGA, oil quality ("OQ"), service age and loading history.

Table 14: Station Transformer HIF

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Dissolved Gas Analysis	22	A,B,C,D,E	4,3,2,1,0	88
Oil Quality	16	A,B,C,D,E	4,3,2,1,0	64
Service Age	16	A,B,C,D,E	4,3,2,1,0	64
Load History	12	A,B,C,D,E	4,3,2,1,0	48
Main Tank Corrosion	5	A,B,C,D,E	4,3,2,1,0	20
Cooling Equipment	5	A,B,C,D,E	4,3,2,1,0	20
Oil Tank Corrosion	2	A,B,C,D,E	4,3,2,1,0	8
Foundation	2	A,B,C,D,E	4,3,2,1,0	8
Grounding	2	A,B,C,D,E	4,3,2,1,0	8
Oil Leaks	3	A,B,C,D,E	4,3,2,1,0	12
Oil Level	3	A,B,C,D,E	4,3,2,1,0	12
Turns Ratio	4	A,B,C,D,E	4,3,2,1,0	16
Winding Resistance	4	A,B,C,D,E	4,3,2,1,0	16

Degradation factor	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	4	A,B,C,D,E	4,3,2,1,0	16
Total Score				400

4.2.1.2. Data Collection and Assumptions

Data was provided for eleven in-service station transformers.

The average DAI for this asset class is 88%.

4.2.1.3. Demographics

Figure 31 presents the age distribution of ERTH's station transformers. As the figure indicates, approximately 91% of station transformer units have been in service for over 30 years.

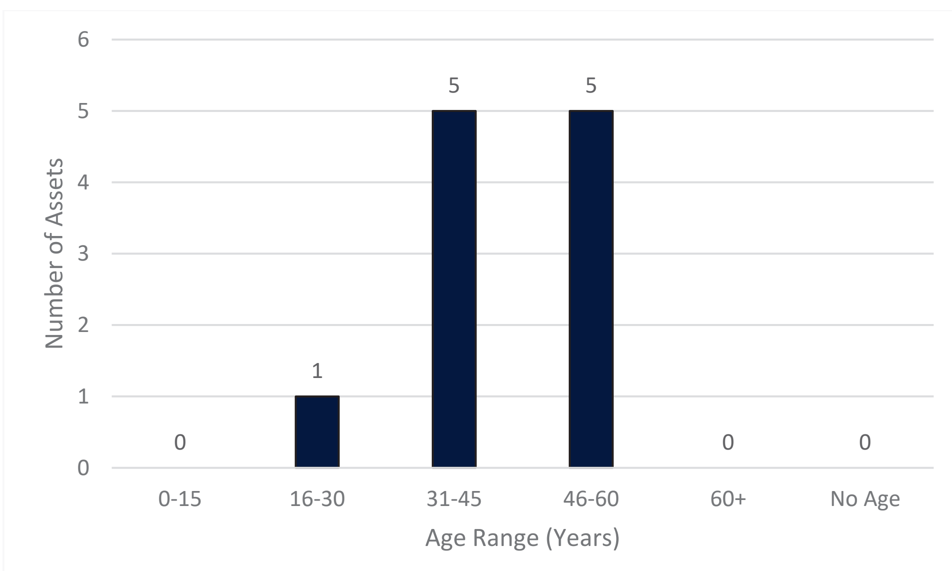

Figure 31: Station Transformer Age Demographics

4.2.1.4. HI Results

The overall HI distribution is presented in Figure 32. All transformers are in Very Good to Fair condition.

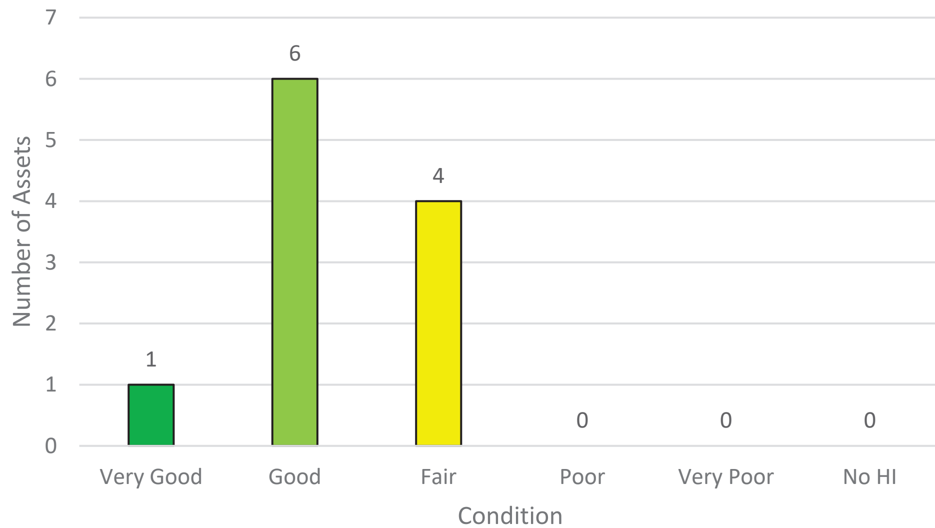

Figure 32: Station Transformer HI Results

Station transformers in Fair condition should be considered for possible remedial work or replacement depending on the unit's criticality. Since power transformers are critical assets, Fair, Poor, and Very Poor condition units are of concern. Table 15 lists the results of the ACA for Station Transformers in order of increasing HI.

Table 15: Station Transformers HI Results

Asset ID	Station ID	Health Index (%)	HI Category
22515-1	BEA-MS1	58%	Fair
A3S6467	GDE-MS4	64%	Fair
301687	CLI-MS1	69%	Fair
307425	PTS-MS1	70%	Fair

Asset ID	Station ID	Health Index (%)	HI Category
A3S6815	GDE-MS2	70%	Good
A3S6029	GDE-MS3	76%	Good
265001001	ING-MS1	76%	Good
A3S6273	AYL-MS1	78%	Good
T2993-1	AYL-MS2	78%	Good
G13572-1	TAV-MS1	84%	Good
2-305405	AYL-MS2	86%	Very Good

HI results for Station Transformers are broken down even further for each transformer. For each transformer, degradation factors with lower grades than 'A' and degradation factors with missing data are highlighted.

A summary of all degradation factors of all station transformers is provided in Table 16.

Table 16: Summary of Degradation factor Results for Station Transformers

Transformer ID	Municipality	Dissolved Gas Analysis	Load History	Oil Quality	Service Age	Main Tank Corrosion	Cooling Equipment	Oil Tank Corrosion	Foundation	Grounding	Oil Leaks	Oil Level	Turns Ratio	Winding Resistance	Insulation Resistance
A3S6273	Aylmer	B	-	A	D	B	B	B	B	A	-	A	A	A	A
2-305405	Aylmer	A	A	A	C	C	B	C	A	A	-	A	A	A	D
T2993-1	Aylmer	A	-	A	D	C	B	C	A	A	-	A	B	A	D

Transformer ID	Municipality	Dissolved Gas Analysis	Load History	Oil Quality	Service Age	Main Tank Corrosion	Cooling Equipment	Oil Tank Corrosion	Foundation	Grounding	Oil Leaks	Oil Level	Turns Ratio	Winding Resistance	Insulation Resistance
22515-1	Beachville	D	-	A	D	C	B	C	B	A	-	A	B	A	C
301687	Clinton	C	A	C	D	B	B	B	B	A	A	A	A	A	A
A3S6815	Goderich	D	A	A	C	C	C	C	A	-	-	A	A	A	A
A3S6029	Goderich	A	-	A	D	B	B	B	B	-	D	D	-	-	-
A3S6467	Goderich	B	A	E	C	C	C	C	B	-	-	A	A	A	A
265001001	Ingersoll	C	A	A	C	C	C	C	A	-	-	A	A	A	A
307425	Port Stanley	C	-	A	C	C	C	C	B	A	-	A	B	A	A
G13572-1	Tavistock	B	A	A	B	C	C	C	B	-	-	A	A	A	A

Aylmer MS1 – A3S6273

The overall HI score for this station power transformer stands at 78%.

Among the negative contributors to the HI score, the Dissolved Gas Analysis received a grade of B. This grade was assigned due to an elevated CO2 level of 16,788 microlitres per litre, exceeding the acceptable threshold of 10,000 microlitres per litre.

Additionally, components such as the main tank, cooling equipment, oil tank, and foundation were also graded as B, indicating areas for improvement in their condition.

It's worth noting that data for several parameters is currently unavailable, including information regarding past loading history and oil leaks.

Aylmer MS2 – 2-305405

The overall HI score for this station power transformer is recorded at 86%.

Among the negative contributors to the HI score, the main tank and oil tank inspections were graded as C, signaling areas of concern in their condition.

Furthermore, the cooling equipment received a grade of B, suggesting a minor level of attention is required in this aspect.

Similar to the previous assessment, data for oil leaks remains unavailable.

Aylmer MS2 – T2993-1

The overall HI score for this station power transformer is 78%.

Among the negative contributors to the HI score, the main tank and oil tank received a grade of C, indicating areas of concern in their condition.

Additionally, the cooling equipment was graded as B, suggesting a minor level of attention is required in this aspect.

Data remains unavailable for past loading history and oil leaks.

Beachville MS1 – 22515-1

The HI score for this station power transformer is 58%.

The Dissolved Gas Analysis received a grade of D due to multiple parameters exceeding permissible levels: CO_2 level at 8,885 microlitres per litre (exceeding 5,500 microlitres per litre), CO level at 908 microlitres per litre (exceeding 500 microlitres per litre), and C_2H_4 level at 67 microlitres per litre (exceeding 60 microlitres per litre).

The main tank and oil tank were graded as C, indicating areas of concern in their condition. Additionally, the cooling equipment and foundation received a grade of B, suggesting areas requiring minor attention.

Data remains unavailable for loading history and oil leaks.

Clinton MS1 – 301687

The HI score for this station power transformer is 69%.

The Dissolved Gas Analysis received a grade of C due to elevated levels of CO_2 at 14,705 microlitres per litre (exceeding 10,000 microlitres per litre) and C_2H_4 at 107 microlitres per litre (exceeding 90 microlitres per litre). The oil quality received a grade of C due to the acid number, which was measured at 0.06 (the threshold for a grade of A is 0.05).

The main tank, cooling equipment, oil tank, and foundation were graded as B, indicating areas for improvement in their condition.

Goderich MS2 – A3S6815

The HI score for this station power transformer is 70%.

The Dissolved Gas Analysis received a grade of D due to elevated levels of CO2 at 18,988 microlitres per litre (exceeding 10,000 microlitres per litre) and CO at 1,347 microlitres per litre (exceeding 900 microlitres per litre).

The main tank, cooling equipment, and oil tank were graded as C, indicating areas of concern in their condition.

Data remains unavailable for grounding and oil leaks.

Goderich MS3 – A3S6029

The HI score for this station power transformer is 76%.

The main tank, cooling equipment, oil tank, and foundation were graded as B, indicating areas with minor defects.

The condition of oil leaks and oil level received a grade of D, suggesting significant issues in these areas.

Data remains unavailable for past loading history, grounding, turns ratio test, winding resistance test, and insulation resistance test.

Goderich MS4 – A3S6467

The HI score for this station power transformer is 64%.

The Dissolved Gas Analysis received a grade of B due to the elevated CO2 level at 22,223 microlitres per litre, surpassing the maximum level of 10,000 microlitres per litre.

The oil quality received an E grade due to the dielectric breakdown which measured 40 kV (under the minimum limit of 41 kV).

The condition of the main tank, cooling equipment, and oil tank were graded as C, indicating areas of concern. The transformer foundation received a grade of B.

Data remains unavailable for grounding and oil leaks.

Ingersoll MS1 – 265001001

The HI score for this station power transformer is 76%.

The Dissolved Gas Analysis received a grade of C due to the elevated CO level at 1,162 microlitres per litre, exceeding the maximum level of 900 microlitres per litre.

The condition of the main tank, cooling equipment, and oil tank were graded as C, indicating areas of concern.

Data remains unavailable for grounding and oil leaks.

Port Stanley MS1 – 307425

The HI score for this station power transformer is 70%.

The Dissolved Gas Analysis for this station power transformer received a grade of C due to elevated levels of CO_2 at 14,558 microlitres per litre (exceeding 10,000 microlitres per litre) and CO at 1,435 microlitres per litre (exceeding 900 microlitres per litre).

The condition of the main tank, cooling equipment, and oil tank were graded as C, indicating areas of concern. The transformer foundation received a grade of B.

Data remains unavailable for past loading history and oil leaks.

Tavistock MS1 – G13572-1

The HI score for this station power transformer is 84%.

The Dissolved Gas Analysis received a grade of B due to the elevated H_2 level at 43 microlitres per litre, exceeding the maximum level of 40 microlitres per litre.

The condition of the main tank, cooling equipment, and oil tank were graded as C, indicating areas of concern. However, the transformer foundation received a grade of B.

Data remains unavailable for grounding and oil leaks.

4.3. Results by Municipality

The following sections provide a breakdown of results by municipality for all asset classes.

4.3.1. Aylmer

The graph below presents the asset condition assessment results in Aylmer.

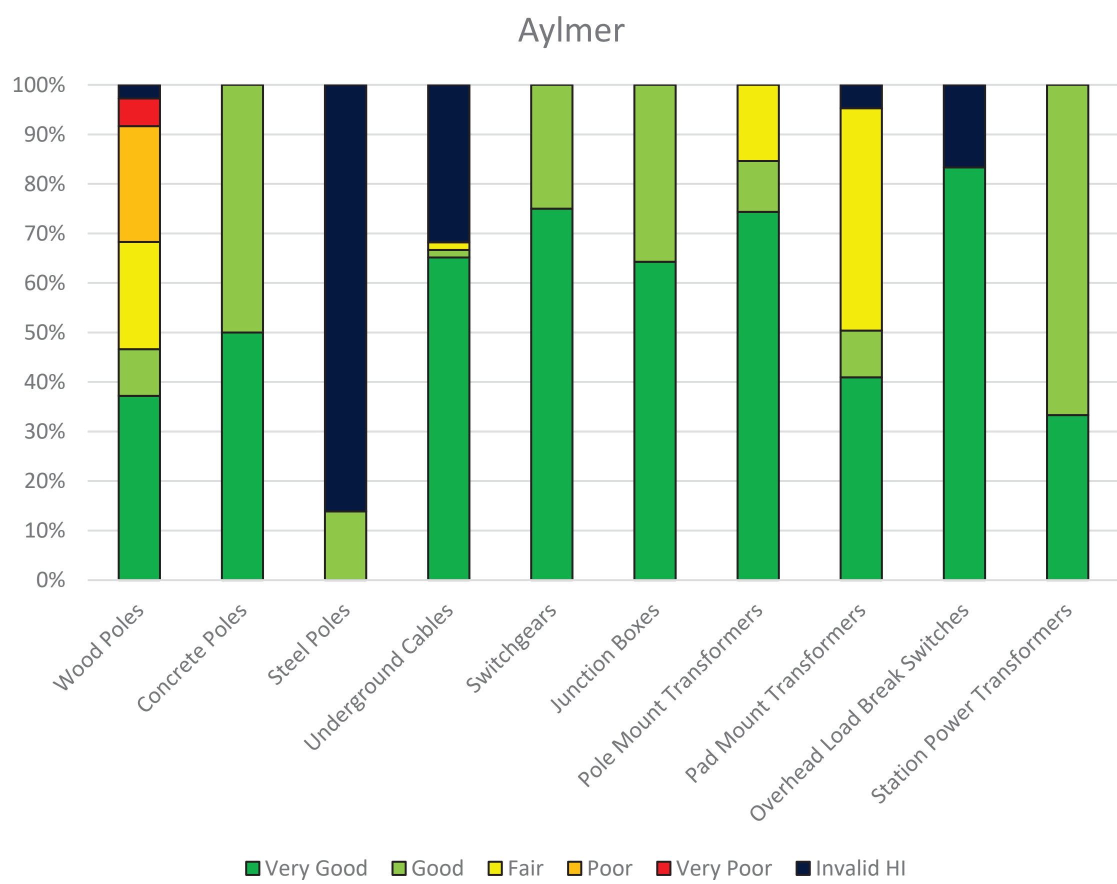

Figure 33: Aylmer Results

4.3.2. Beachville

The graph below presents the asset condition assessment results in Beachville.

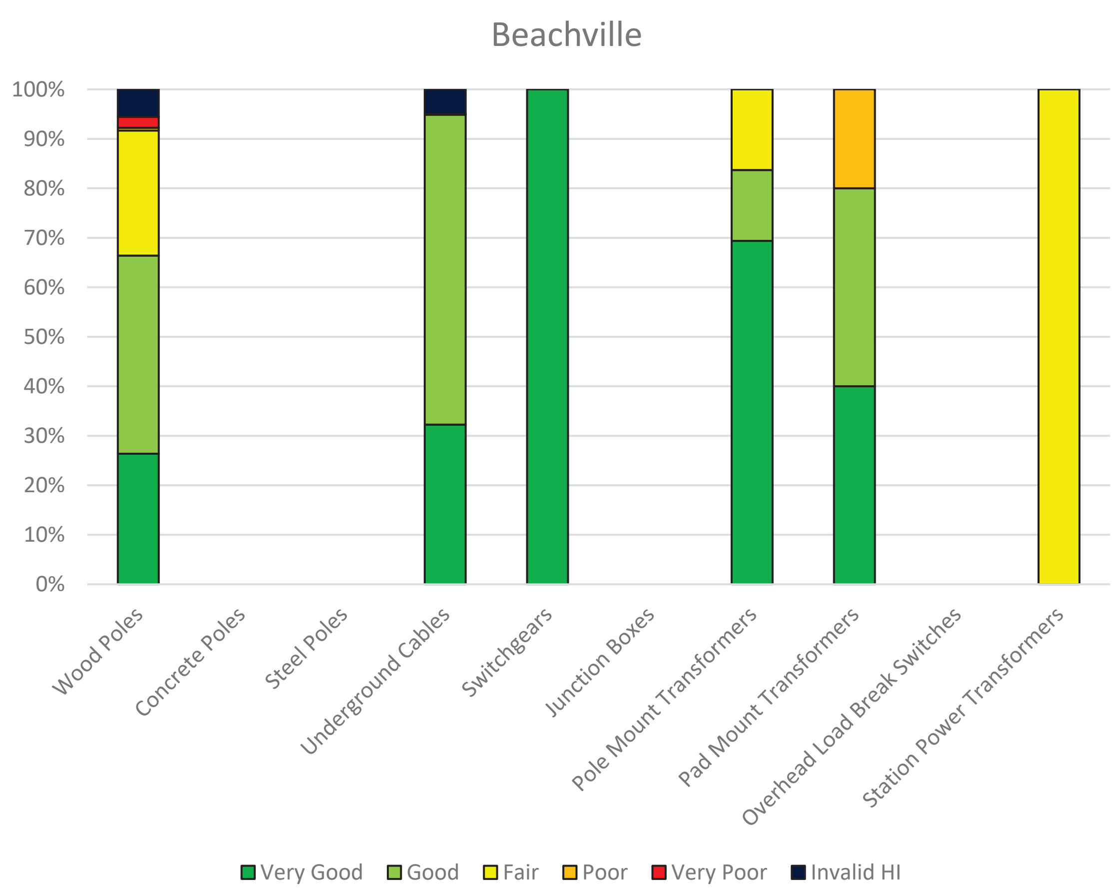

Figure 34: Beachville Results

4.3.3. Belmont

The graph below presents the asset condition assessment results in Belmont.

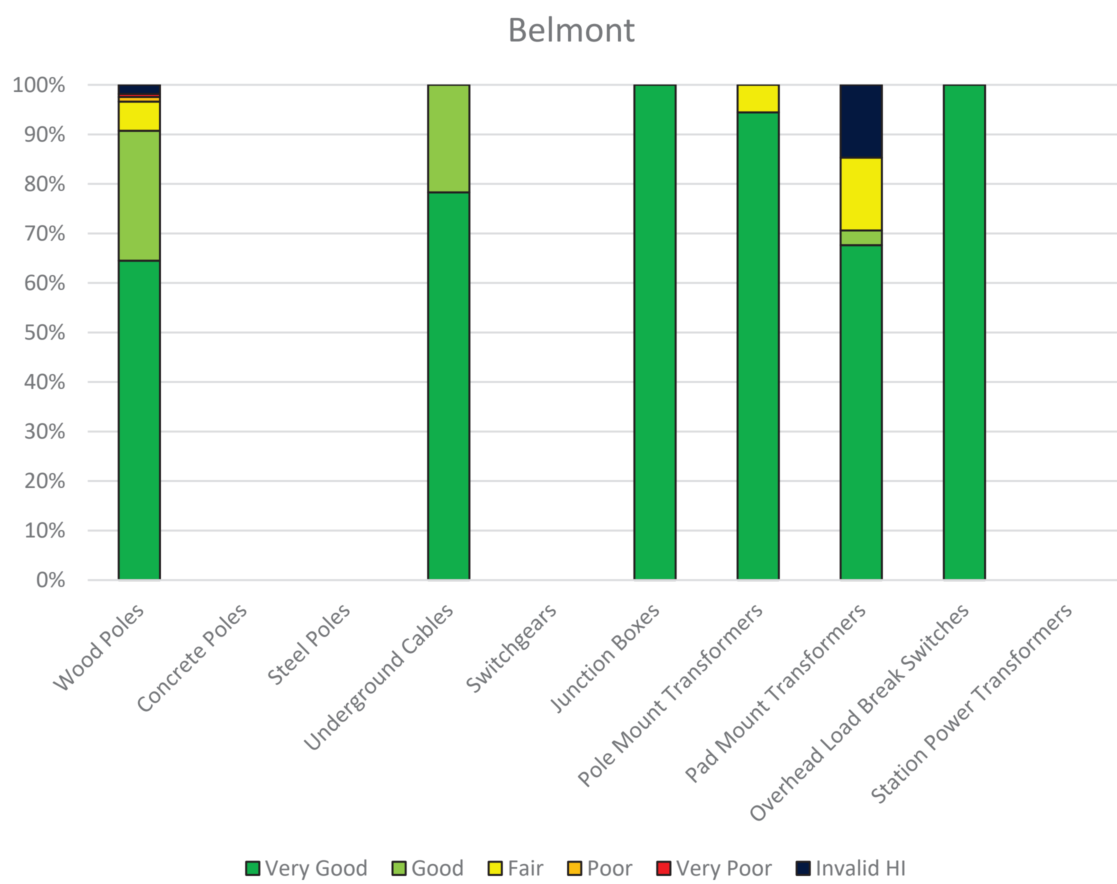

Figure 35: Belmont Results

4.3.4. Burgessville

The graph below presents the asset condition assessment results in Burgessville.

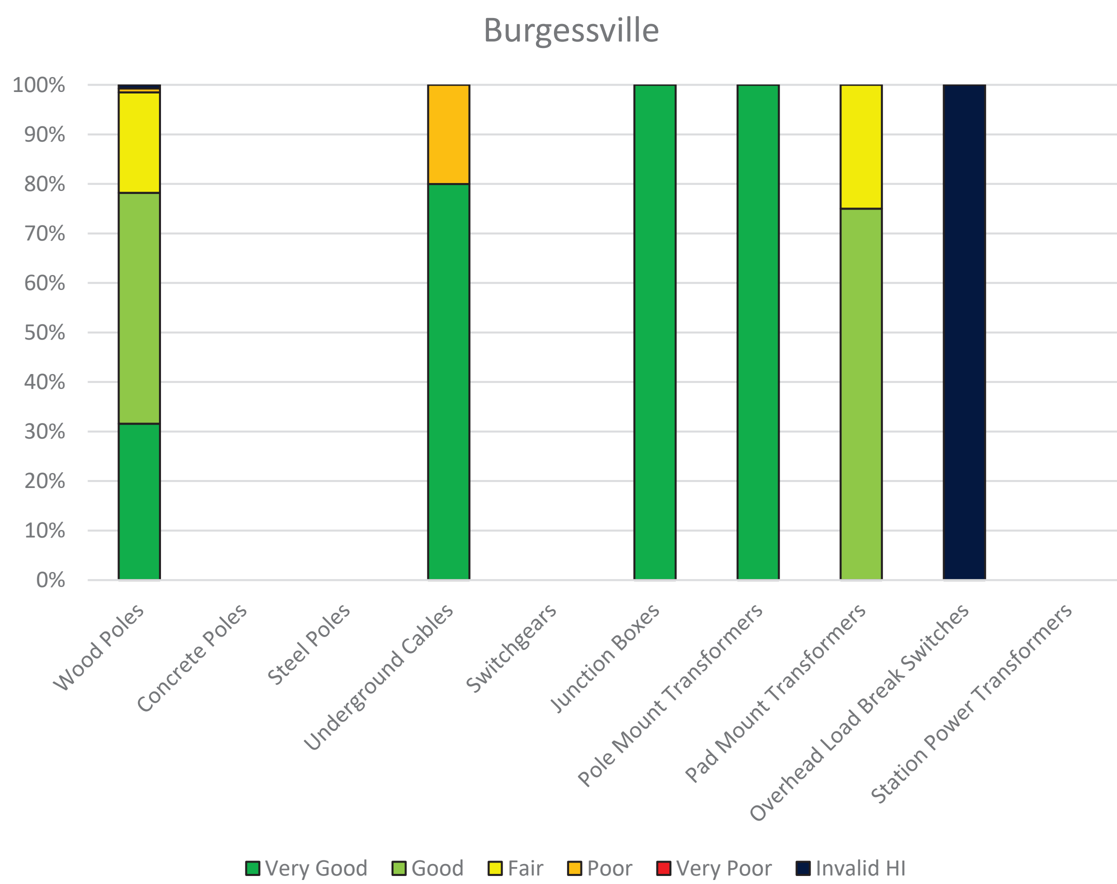

Figure 36: Burgessville Results

4.3.5. Clinton

The graph below presents the asset condition assessment results in Clinton.

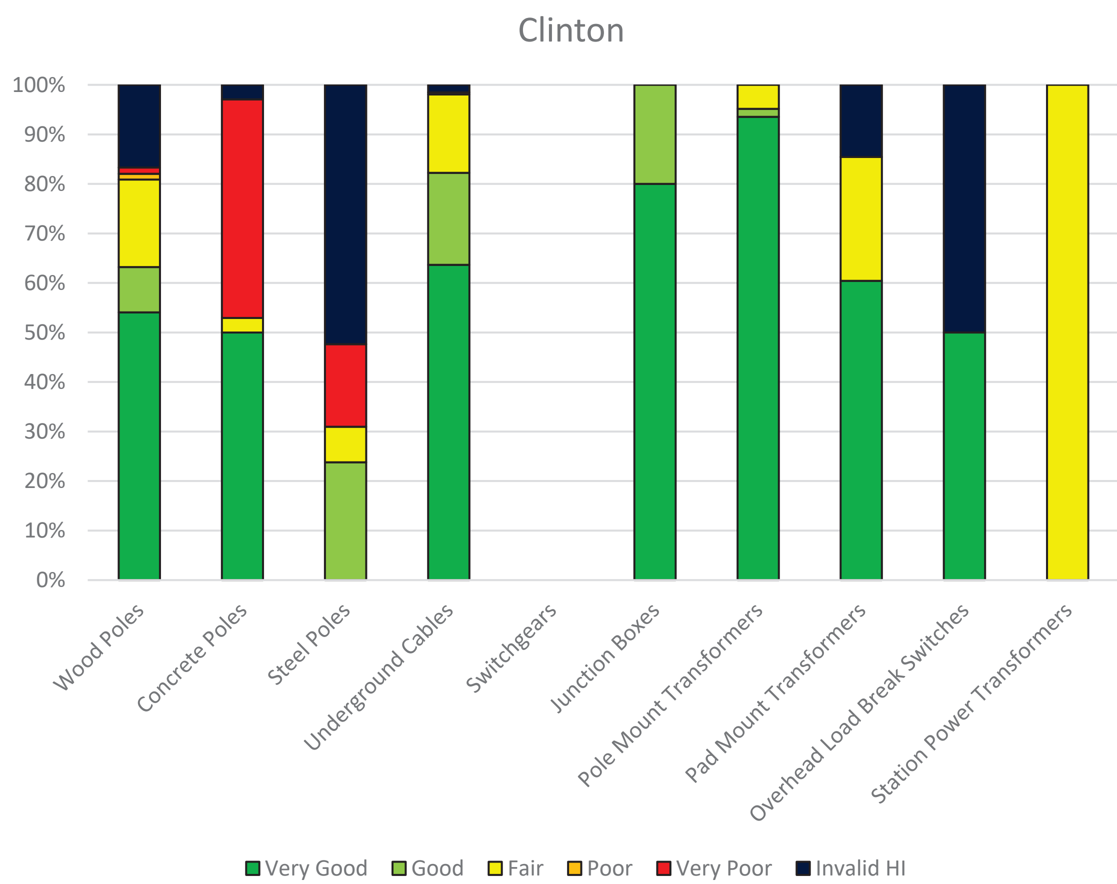

Figure 37: Clinton Results

4.3.6. Dublin

The graph below presents the asset condition assessment results in Dublin.

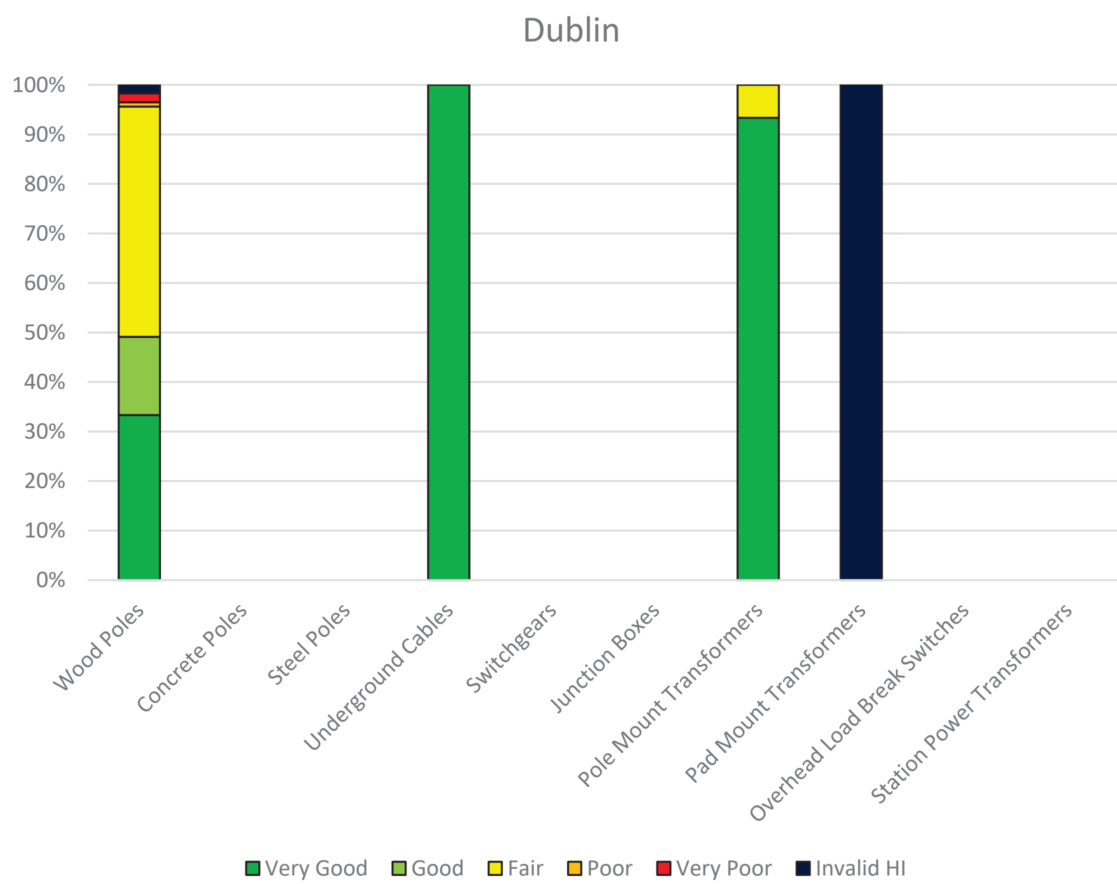

Figure 38: Dublin Results

4.3.7. Embro

The graph below presents the asset condition assessment results in Embro.

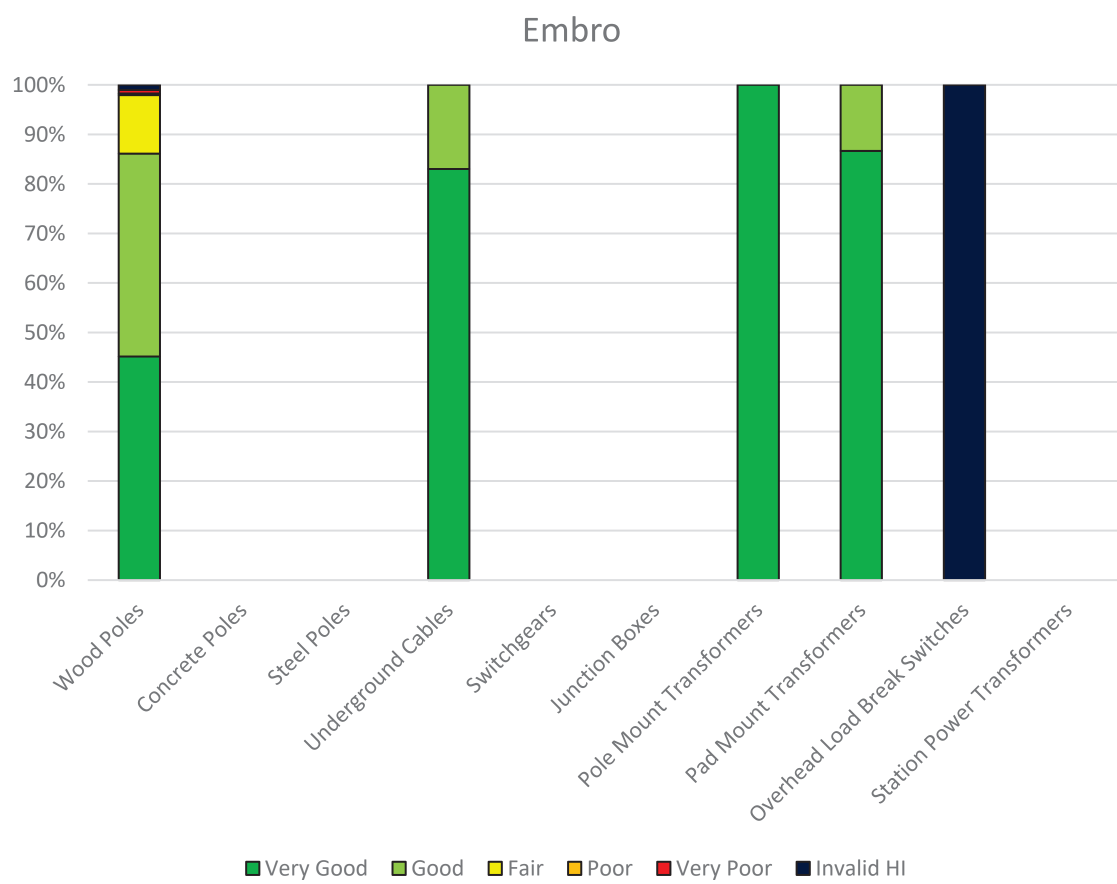

Figure 39: Embro Results

4.3.8. Goderich

The graph below presents the asset condition assessment results in Goderich.

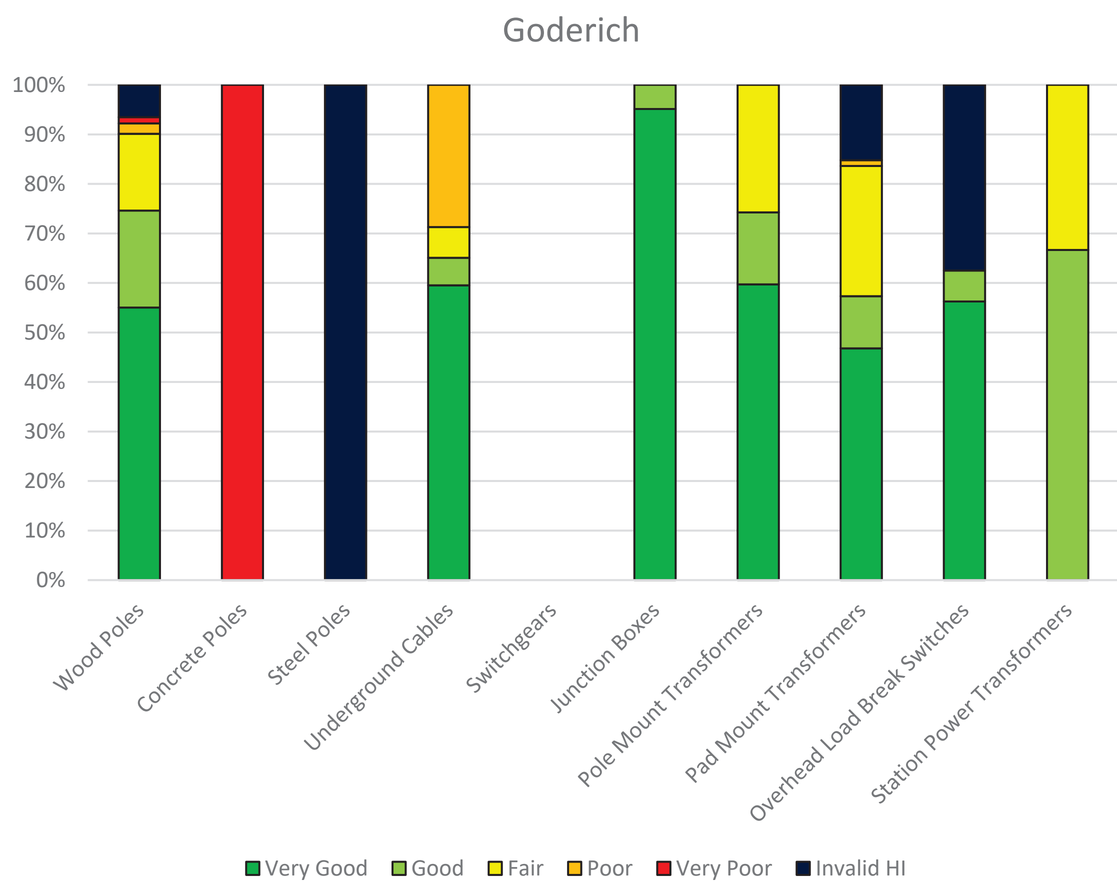

Figure 40: Goderich Results

4.3.9. Ingersoll

The graph below presents the asset condition assessment results in Ingersoll.

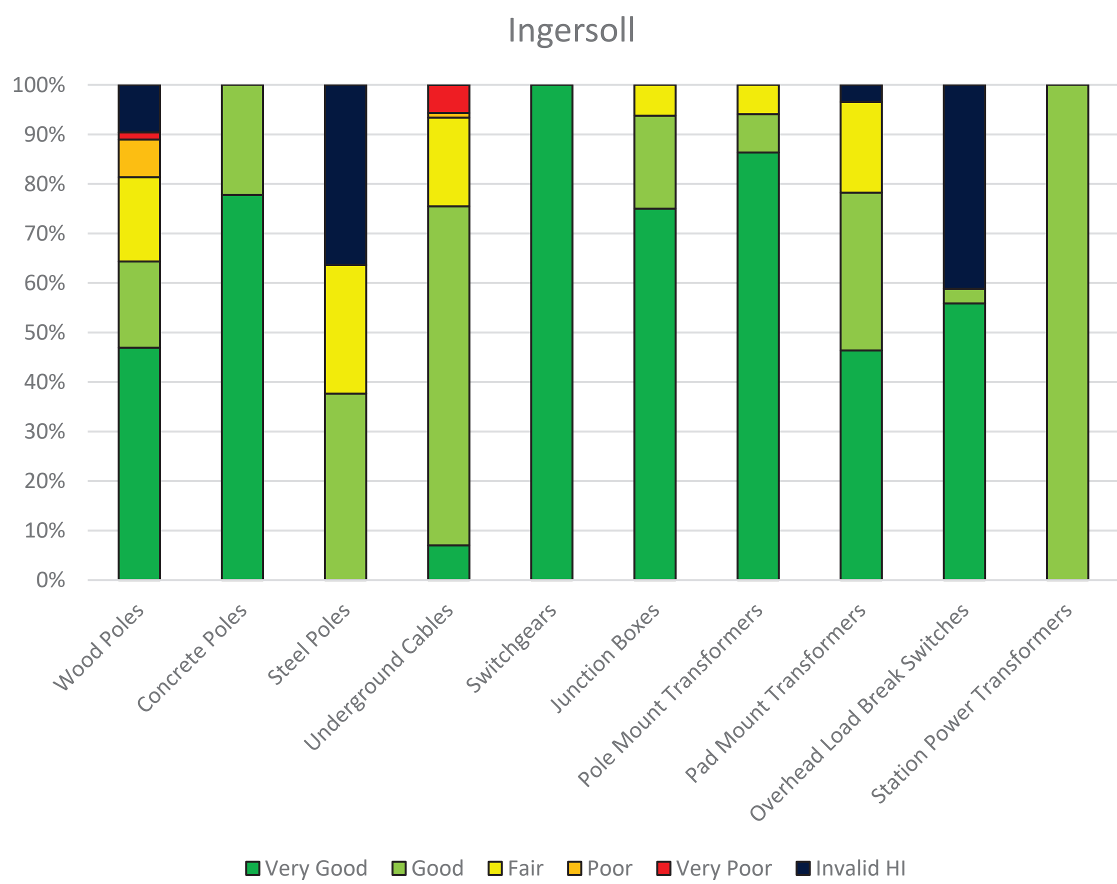

Figure 41: Ingersoll Results

4.3.10. Mitchell

The graph below presents the asset condition assessment results in Mitchell.

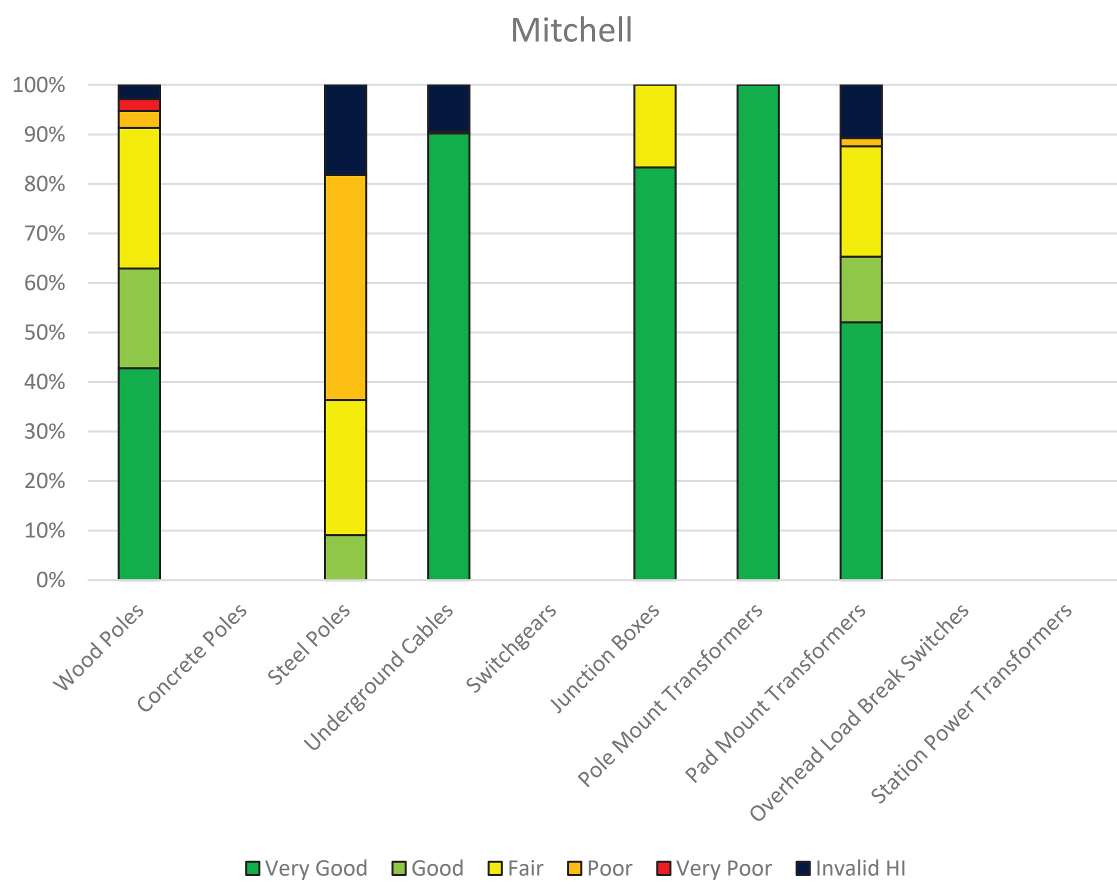

Figure 42: Mitchell Results

4.3.11. Norwich

The graph below presents the asset condition assessment results in Norwich.

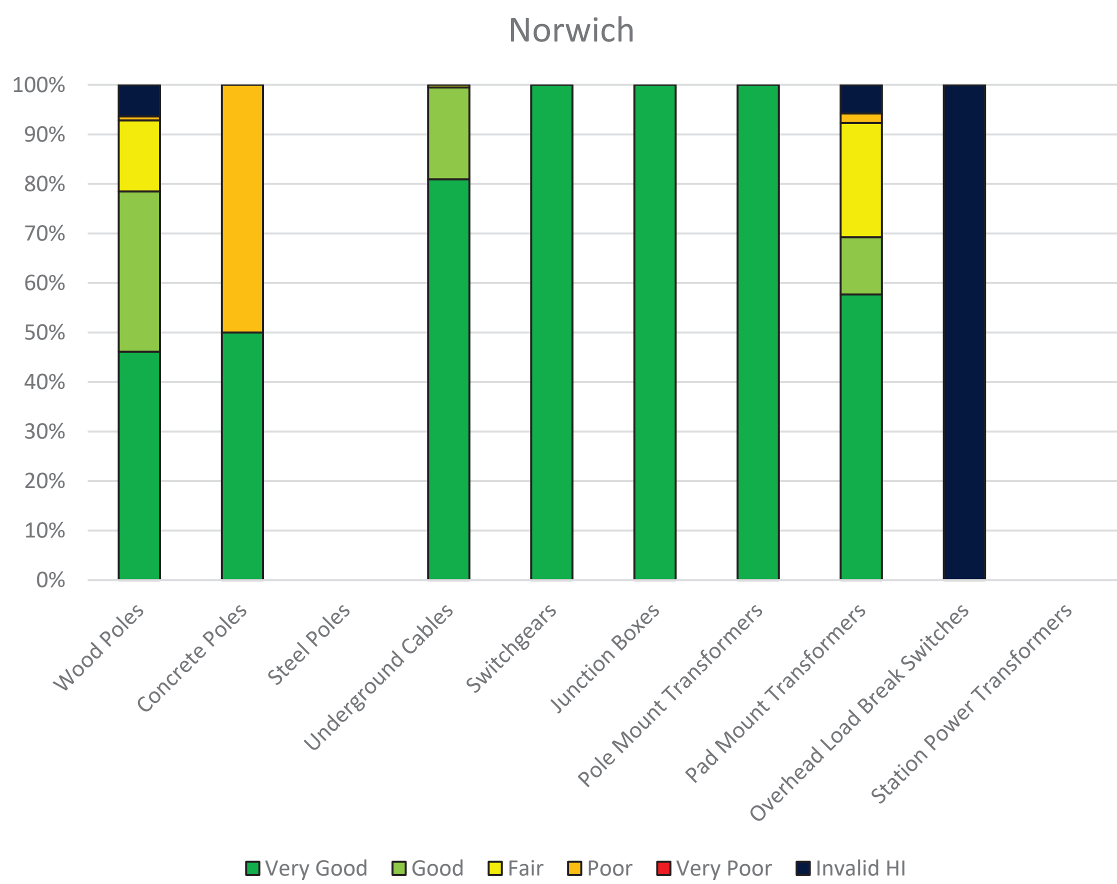

Figure 43: Norwich Results

4.3.12. Otterville

The graph below presents the asset condition assessment results in Otterville.

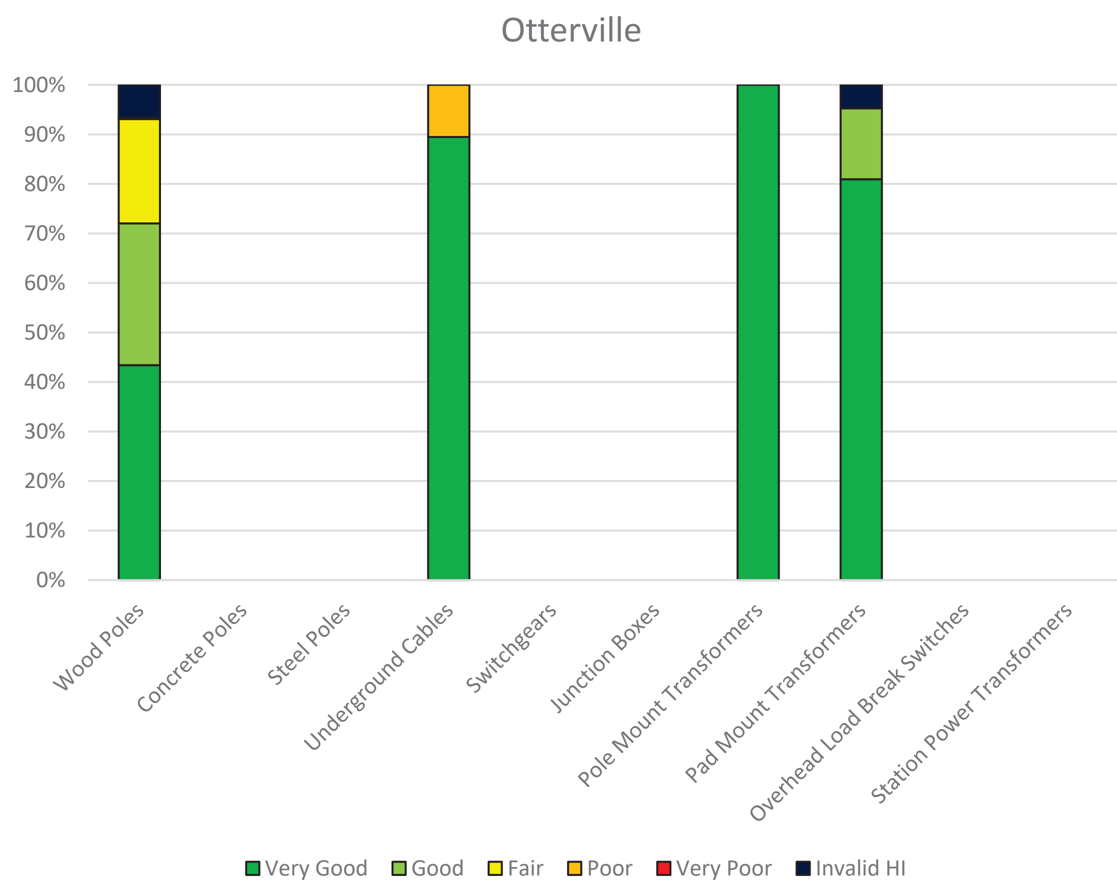

Figure 44: Otterville Results

4.3.13. Port Stanley

The graph below presents the asset condition assessment results in Port Stanley.

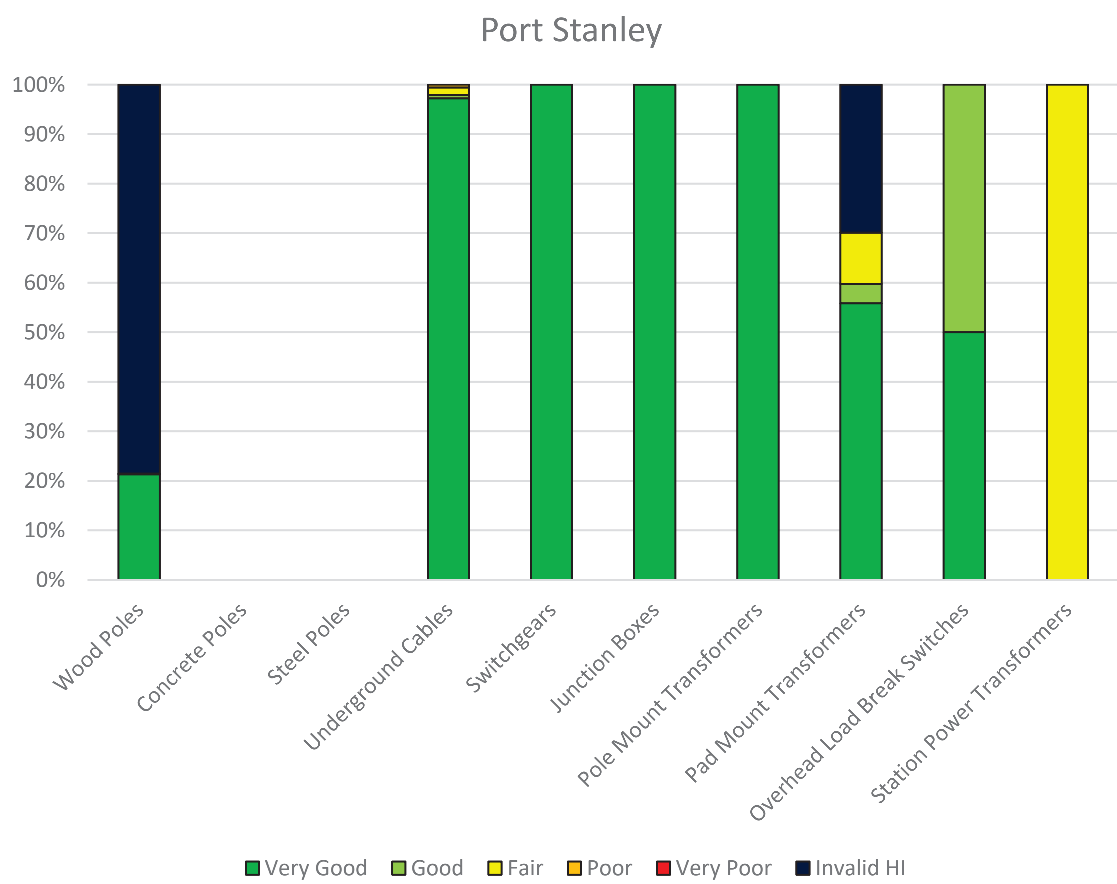

Figure 45: Port Stanley Results

4.3.14. Tavistock

The graph below presents the asset condition assessment results in Tavistock.

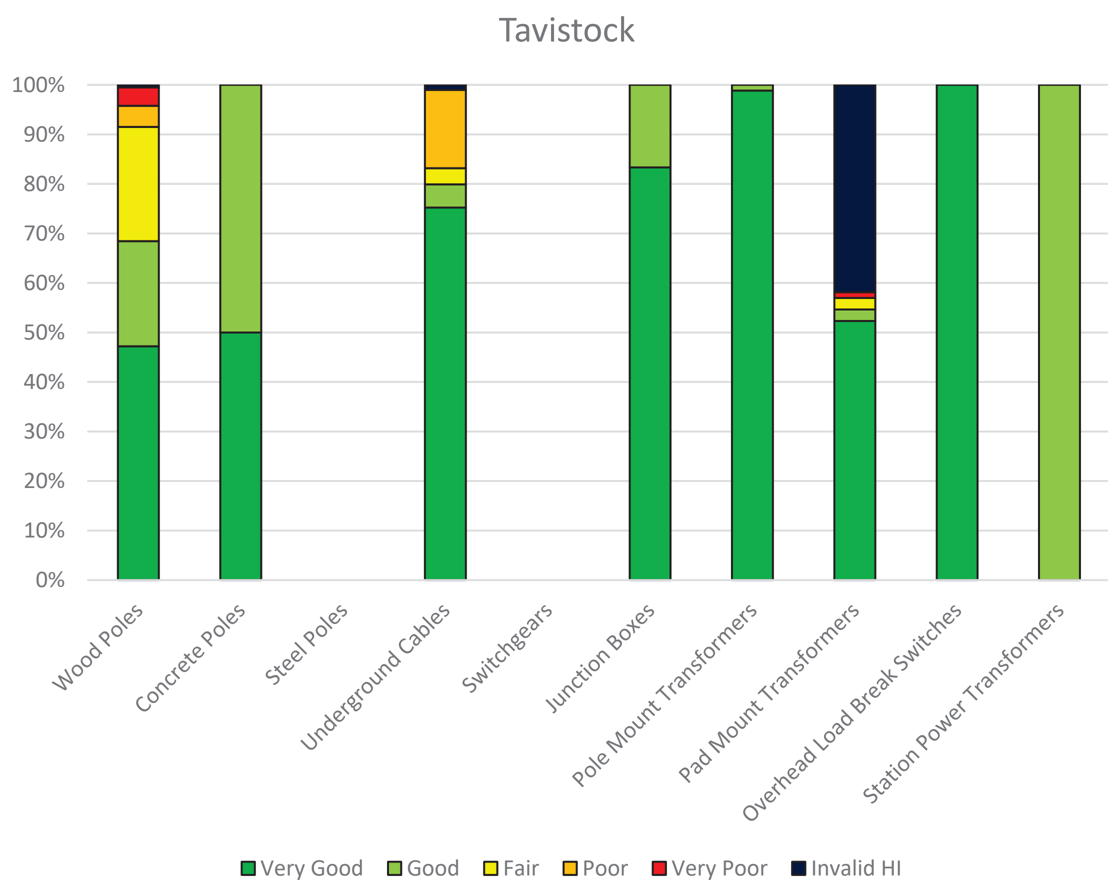

Figure 46: Tavistock Results

4.3.15. Thamesford

The graph below presents the asset condition assessment results in Thamesford.

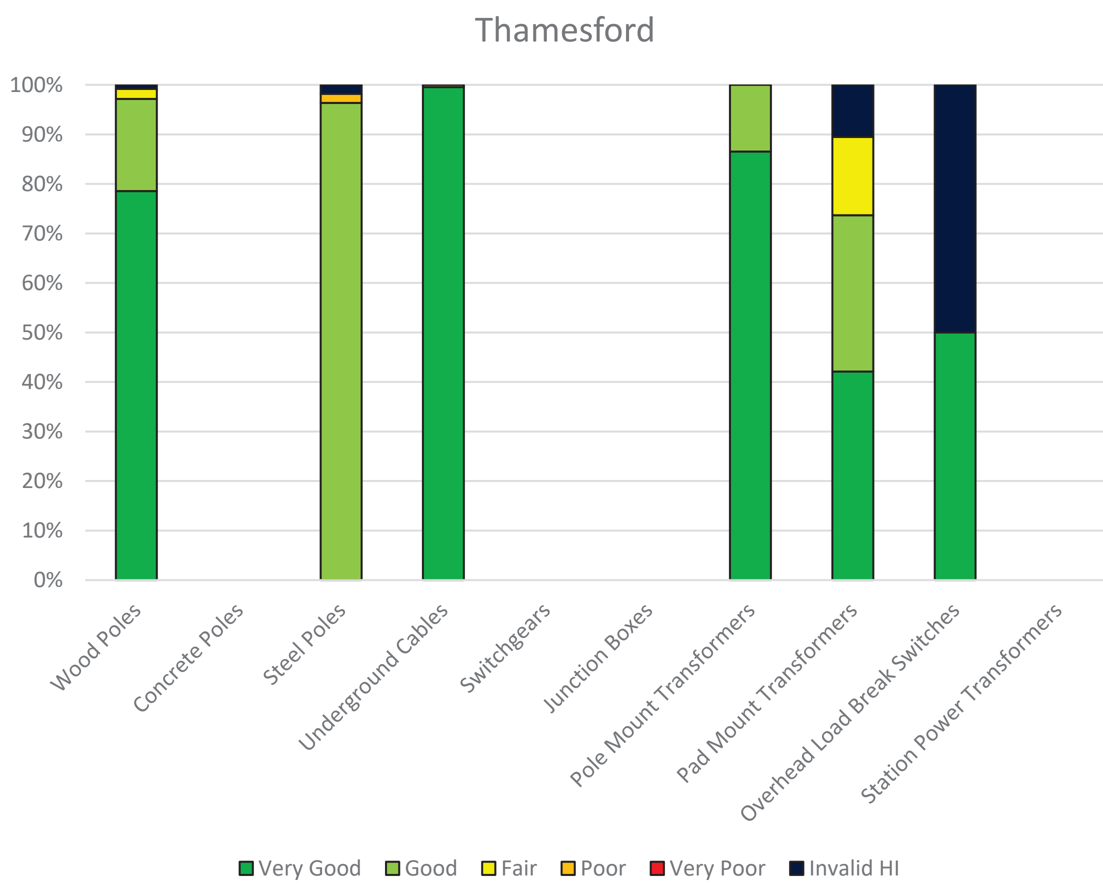

Figure 47: Thamesford Results

4.3.16. Unknown

The graph below presents the asset condition assessment results in Unknown areas.

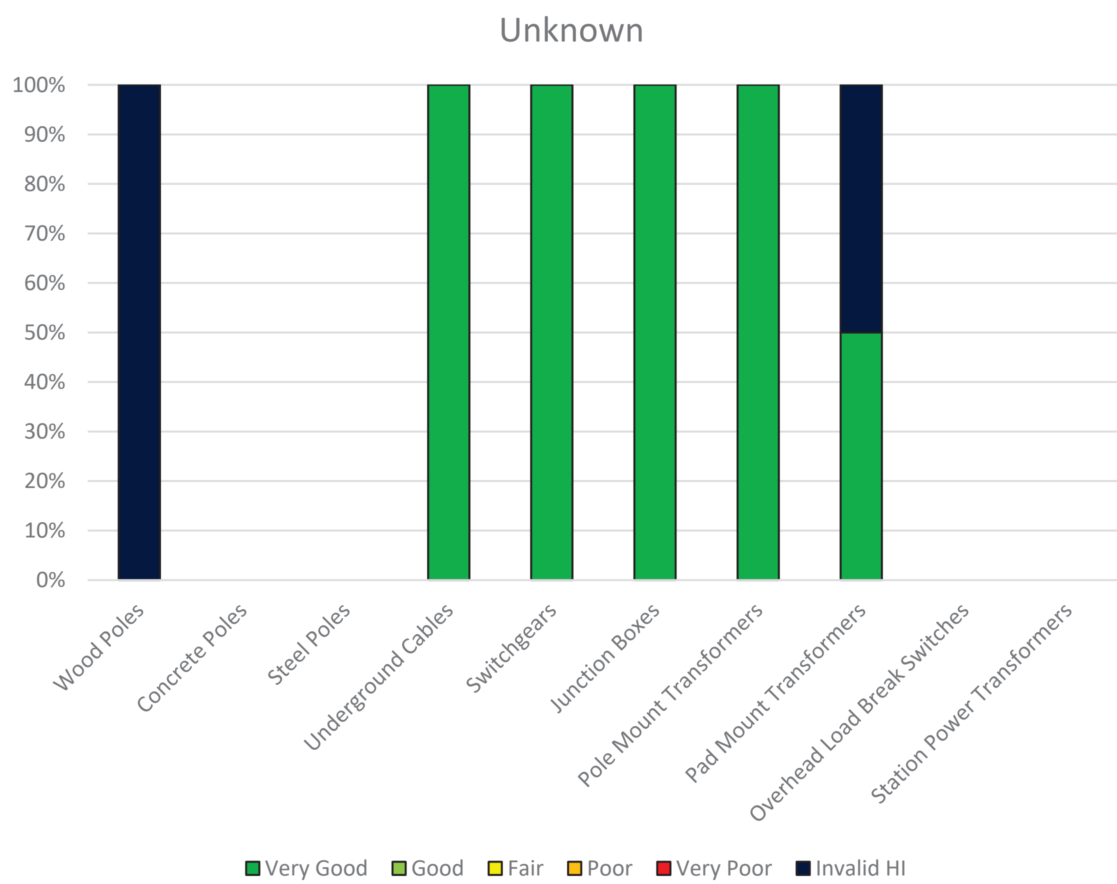

Figure 48: Unknown Results

5. Recommendations

5.1. Advanced Asset Degradation factors

Primarily, BBA recommends that ERTH should focus their efforts on collecting data for existing degradation factors to improve the accuracy and value of its new framework. More advanced parameters can later be integrated which typically represent the measurements associated with equipment degradation processes known to be most detrimental to the normal operation of electrical assets over time.

The following set of recommendations consolidates BBA's suggestions provided throughout Chapter 5. The recommendations target additional degradation factors or the means of collecting and storing the data already being utilized . The recommendations are based on the advanced ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted.

5.1.1. Wood Poles

Visual inspection processes should be modified to ensure that key data – particularly defects, wood rot, and vertical alignment – are collected as condition codes (A,B,C,D,E). Inspection services should be advised to give consistent reporting of remaining strength, preferably as a percentage of remaining life. Pole testing should be completed for all wood poles over ten years of age to verify the condition.

We note that aside from the gaps in the data records, ERTH collects a substantial number of data parameters that enable the production of a relatively advanced HI formulation. Should the utility consider expanding the scope of inspection data collection, additional degradation factors for this asset class may include:

- Cavities (Hammer/Resistograph)

Table 17: Criteria for Wood Pole Cavities

Condition Rating	Corresponding Condition
A	Cavity < 10% for both tests or Passed Hammer Test
B	Cavity ≥ 10% for either test

Condition Rating	Corresponding Condition
C	Cavity ≥ 20% for either test
D	Cavity ≥ 30% for either test
E	Cavity ≥ 50% for one test and ≥ 40% for second test or Failed Hammer Test

5.1.2. Concrete Poles

While the DAI for concrete poles is low and needs to be improved, it should also be noted that concrete poles comprise a small portion of the pole population and, therefore, have a lesser impact on renewal planning.

Nevertheless, the utility will continue operating a system that features a number of concrete poles for the foreseeable future. As such, near-term enhancements to the current data collection and tracking practices are in order. Demographic data, such as installed date should be established for every pole and a full visual inspection should take place.

Recognized HI guides recommend more than a two-parameter formulation to develop a robust index. A best-practice formulation would consider degradation factors such as:

- Evidence of other defects; and
- Out of plumb.

Once there is more data, ERTH can use the following grading scheme:

Table 18: Criteria for Concrete Pole Defects

Condition Rating	Corresponding Condition
A	No signs of any defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking.
B	Signs of minor defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking.

Condition Rating	Corresponding Condition
C	Signs of significant defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking.
D	Signs of serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking.
E	Signs of very serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking.

Table 19: Criteria for Concrete Pole Out of Plumb

Condition Rating	Corresponding Condition
A	There is no displacement of footings from the original installed condition, and there is no disorientation, the pole is perfectly straight.
B	There is minor pole disorientation but is acceptable and does not require corrective action.
C	There is significant displacement of footings and/or there is significant disorientation, requiring planned corrective action.
D	Major displacement of footings and/or major disorientation of the pole in present requiring immediate emergency repairs.
E	Serious displacement of footings and disorientation of the pole in present requiring immediate emergency repairs.

5.1.3. Steel Poles

Similar to concrete poles, ERTH maintains and operates a limited number of steel poles.

These poles are also inspected in the same manner as concrete poles. However, with steel poles, special consideration needs to be given to potential corrosions which can ultimately degrade the asset's structural integrity. In addition to the same recommendations for concrete poles, BBA also recommends to a conduct a visual inspection of steel poles specifically aimed at assessing the amount of rust/corrosion.

Table 20: Criteria for Steel Pole Corrosion

Condition Rating	Corresponding Condition
A	There is no sign of rusting/corrosion on the pole and the pole is in like new condition.
B	Minor signs of rusting/corrosion (presence of paint bubbles or metal pitting) on the pole, does not require corrective action. Minimal deterioration.
C	Significant signs of rusting/corrosion on the pole(signs of rust in form of red, black or white corrosion, pitting of surface, but pole is still structurally sound), requiring planned corrective action. Significant deterioration.
D	Major signs of rusting/corrosion on the pole(the corroded area of pole has small pin holes and is unsound), requiring immediate emergency repairs. Major deterioration.
E	Extreme signs of rusting/corrosion on the pole(Metal has been penetrated through over large area and the pole is structurally unsound).

5.1.4. Underground Cables

We recommend that ERTH should develop a complete AM Plan for underground cables. Decisions such as when to test and whether to inject cables or replace them should be rationalized. In addition, cable testing data should be tracked against cable demographics to correlate age and type with life expectancy.

Cable testing should also consider the condition of concentric neutral as it can pose safety risks when degraded. It is also recommended to track the number of splices and inspect the condition of splices during cable testing.

The following types of condition information may assist ERTH in its efforts to plan its replacement needs with additional confidence:

- VLF tanδ and partial discharge testing;
- Time-domain reflectometry (condition of concentric neutral); and
- Visual inspection of terminations and splices.

Once there is more data regarding insulation condition, ERTH can use the following grading schemes:

Table 21: Criteria for VLF Tanδ and Partial Discharge Testing

Condition Rating	Corresponding Condition
A	No abnormal findings
C	Minor Partial discharge or tanδ observed
E	Major Partial discharge or tanδ observed

Table 22: Criteria for Concentric Neutral

Condition Rating	Corresponding Condition
A	No abnormalities detected
C	Un-jacketed bare concentric neutral – clay soil; feeder cable with known neutral corrosion
D	Un-jacketed bare concentric neutral – sandy soil
E	One half/one third neutral size underground distribution cable with known neutral corrosion; full neutral size underground distribution cable with known neutral corrosion

Table 23: Criteria for Visual Inspection of Splices

Condition Rating	Corresponding Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

5.1.5. Switchgears

At a minimum, age and condition data should be made available for all installations. Pad-mounted switchgear is often tracked by serial number because of the potential for switchgear to be removed from one location, rehabilitated, and then installed elsewhere.

IR scans should be completed for all pad-mounted switchgear to identify hotspots and collected as condition codes (A,B,C,D,E).

In addition to the currently collected visual inspection results, ERTH can also aim to include visual inspections of terminations, blades, and operating mechanism to its inspection cycles.

Table 24: Criteria for Condition of Terminations

Condition Rating	Corresponding Condition
A	Terminations are tight, free from corrosion and show no sign of overheating. Cables are adequately supported and impose no excessive loading on switchgear during normal or fault interrupting duty
B	Minor signs of wear with respect to the above characteristics
C	Significant signs of degradation with respect to the above characteristics, but they do not impact safe operation of the switchgear

Condition Rating	Corresponding Condition
D	Serious deficiencies with respect to the above listed characteristics requiring repairs during the next scheduled outage
E	Very serious deficiencies with respect to the above listed characteristics requiring immediate repairs or replacement

Table 25: Criteria for Condition of Blades

Condition Rating	Corresponding Condition
A	Blades are clean, free from corrosion, cracks, distortion, abrasion or obstruction. All fasteners are tight. No visible evidence of looseness, loss of adjustment, or excess bearing wear
B	Minor signs of wear with respect to the above listed deficiencies
C	Significant signs of wear with respect to the above listed deficiencies, but the deficiencies are not critical to the safe operation of the switchgear
D	Blades are degraded requiring replacement during the next scheduled outage
E	Blades are damaged/degraded beyond repair, requiring immediate replacement

Table 26: Criteria for Condition of Operating Mechanism

Condition Rating	Corresponding Condition
A	Operating mechanism is in good condition. No sign of overheating or deterioration. No evidence of moisture or condensation or insect ingress into control cabinet

Condition Rating	Corresponding Condition
B	Normal signs of wear of control components based on the above listed characteristics
C	Significant wear of control components based on the above listed characteristics, but it does not affect safe operation of the switchgear
D	Unacceptable level of degradation of control components based on the above listed characteristics, requiring component replacement/repairs during the next scheduled outage
E	Switch operator controls defective, damaged, or degraded, requiring immediate replacement

5.1.6. Junction Boxes

Similar to switchgears, BBA primarily recommends ERTH to improve its data collection and storage processes in order to maintain age and condition records for all of its junction boxes. The above additional recommendations made for switchgears are also applicable for junction boxes.

Table 27: Criteria for Visual Inspection of Splices

Condition Rating	Corresponding Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

5.1.7. Pole-Mounted Transformers

Age information should be collected for assets missing age data. It is recommended that ERTH establish purchase dates, (or installed dates as a proxy) and transformer demographics for all pole-mounted transformers as part of a regular inspection.

The following additional degradation factor may provide useful insight subject to the economics of assessing the remaining lives of ERTH's pole-mounted transformer population for longer-term planning:

- Peak loading history.

Table 28: Criteria for Peak Loading History

Condition Rating	Corresponding Condition
A	Typical peak load less than 50% of its rating
B	Typical peak load of 50% to 75% of its rating
C	Typical peak load of 75% to 100% of its rating
D	Typical peak load of 100% to 125% of its rating
E	Typical peak load of greater than 125% of its rating

5.1.8. Pad-Mounted Transformers

At a minimum, age data should be made available for all units. Because of the potential for transformers to be removed from one location, rehabilitated and then installed elsewhere, transformers are often tracked by serial number.

In addition to rectifying the data gaps across the degradation factors already being collected, BBA encourages ERTH to consider collecting some of the incremental condition information associated with advanced AM practices:

- Peak loading history; and
- IR scan.

The grading scheme for peak loading history for pad-mounted transformers is identical to that of pole-mounted transformers. Infrared scanning can be graded as follows:

Table 29: Criteria for Infrared Scanning

Condition Rating	Corresponding Condition
A	No Hotspots detected
C	Minor Hotspots/Hotspots on connections detected
E	Major Hotspots detected

5.1.9. Overhead Load Break Switch

Considering the value of the overhead switch asset to the operation of the utility, all missing data should be collected which includes the collecting or estimating of age data.

Condition data from visual inspection should be collected and translated into condition scores (A,B,C,D,E) and consolidated in the asset registry. Electronic field data collection methods are preferred.

5.1.10. Station Transformers

Station transformers are critical assets for a distribution utility both in terms of asset value and impact on reliability. Each station transformer should be assessed on an individual level and a specific plan for maintenance, rehabilitation, or replacement should be developed.

Station transformers should be replaced before the risk of failure increases. In cases where the condition is slipping, additional monitoring and testing including, in some cases, online monitoring can be put in place to reduce risk. Also, stations with back-up configurations, either internally or externally are at lower risk should equipment fail.

In order to better estimate the risk of failure for station transformers, BBA recommends ERTH reconducts its electrical testing for all of its in service transformers in order to improve data availability. BBA also recommends the implementation of a more comprehensive visual inspection cycle to better track the physical condition of the asset.

In addition to rectifying the data gaps across the degradation factors already being collected, BBA encourages ERTH to consider collecting some of the incremental condition information associated with advanced AM practices:

- Insulation power factor;
- Bushing power factor;
- Infrared scanning;
- Visual inspection of bushings, gaskets and seals, and connectors;
- Excitation current; and
- Dissipation factor.

Grading schemes for each additional degradation factor is listed below:

Table 30: Criteria for Insulation Power Factor

Condition Rating	Corresponding Condition
A	PFMAX < 0.5
B	0.5 ≤ PFMAX < 1
C	1 ≤ PFMAX < 1.5
D	1.5 ≤ PFMAX < 2
E	PFMAX ≥ 2

Table 31: Criteria for Bushing Power Factor Test

Condition Rating	Bushing PF % Deviation
A	0 ≤ % Deviation ≤ 1.25
B	1.25 < % Deviation ≤ 1.5

Condition Rating	Bushing PF % Deviation
C	1.5 < % Deviation ≤ 1.75
D	1.75 < % Deviation ≤ 2
E	2 < % Deviation

Table 32: Criteria for Infrared Scanning of Power Transformer

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point of transformer at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees over reference point.
C	Significant hot spots are identified and further investigation is required; excess of 10-20 degrees over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees over reference point.
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees over reference point.

Table 33: Criteria for Visual Inspection of Bushings

Condition Rating	Corresponding Condition
A	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash, and copper wash. Cementing and fasteners are secure. No discolouring.

Condition Rating	Corresponding Condition
B	Bushings are not broken, but minor chips and cracks are visible. Cementing and fasteners are secure.
C	Bushings are not broken; however, major chips and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	Bushings are broken or cementing and fasteners are not secure.
E	Bushings, cementing, or fasteners are broken/damaged beyond repair.

Table 34: Criteria for Visual Inspection of Gaskets and Seals

Condition Rating	Corresponding Condition
A	No external sign of deterioration of tank gaskets, weld seams, or gaskets on valve fittings.
B	Normal signs of wear with respect to the above characteristics.
C	One of the above characteristics is unacceptable.
D	Two or more of the above characteristics are unacceptable – repairable.
E	Two of more of the above characteristics are unacceptable – damaged beyond repair.

Table 35: Criteria for Visual Inspection of Connectors

Condition Rating	Corresponding Condition
A	All primary and secondary connections are in good condition.

Condition Rating	Corresponding Condition
B	Normal signs of wear with respect to the primary and/or secondary connectors.
C	Primary or secondary connectors are in unacceptable condition.
D	Both primary and secondary connectors are in unacceptable condition – repairable.
E	Both primary and secondary connectors are in unacceptable condition – damaged beyond repair.

Table 36: Criteria for Excitation Current

Condition Rating	Corresponding Condition
A	0-5%
B	5.1-7.5%
C	7.6-10%
D	10.1-15%
E	>15%

Table 37: Criteria for Dissipation Factor

Condition Rating	Corresponding Condition
A	0-0.49
B	0.5-0.99

Condition Rating	Corresponding Condition
C	1-1.49
D	1.5-1.99
E	2+

6. Conclusion

On top of a condition assessment of ERTH's major asset classes, this report provided ERTH with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance its asset management analytics. As our final recommendation, we suggest that ERTH invest some time and analytical resources into the development of a comprehensive Strategic Asset Management Plan ("SAMP") that would prescribe the utility's approach to the collection and management of asset data for each asset class.

This concludes BBA's Asset Condition Assessment report for ERTH's assets. We thank ERTH's staff and management for the opportunity to participate in this complex study and for their ongoing support throughout its development.

Appendix A. Degradation factors Grading Tables

A.1. Wood Poles

Table 38: 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 39: 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%

Table 40: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component requires immediate replacement

Table 41: Criteria for Wood Rot

Condition Rating	Corresponding Condition
A	There is no wood rot
B	Slight wood rot in a few areas
C	Slight wood rot is present in many areas and/or moderate wood rot present
D	Moderate rot was present in a few locations or Extensive wood rot was noted in the inspection
E	Wood rot is extensive in many areas

A.2. Concrete Poles

Table 42: 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

Table 43: Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	There is no sign of rusting/corrosion on the pole and the pole is in like new condition
B	Minor signs of rusting/corrosion on the pole, does not require corrective action. Minimal deterioration
C	Significant signs of rusting/corrosion on the pole, requiring planned corrective action. Significant deterioration
D	Major signs of rusting/corrosion on the pole requiring immediate emergency repairs. Major deterioration
E	Serious signs of rusting/corrosion on the pole. Serious deterioration

A.3. Steel Poles

Table 44: 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 60 years
E	Over 60 years

Table 45: Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	Pole is in "as new" condition
B	Pole has normal wear expected with age
C	Pole has many minor problems or a major problem that requires close attention and monitoring
D	Pole has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed or is replaced within a few years
E	Pole requires immediate replacement

A.4. Underground Cables

Table 46: Criteria for Service Age (XLPE)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 15 years
C	16 to 20 years
D	21 to 25 years
E	25 years and older

Table 47: Criteria for Service Age (TR-XLPE)

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 30 years
C	31 to 40 years
D	41 to 50 years
E	50 years and older

Table 48: Criteria for Service Age (AL)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years

Condition Rating	Corresponding Condition
C	21 to 30 years
D	31 to 34 years
E	35 years and older

Table 49: Criteria for Service Age (CU)

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 30 years
C	31 to 40 years
D	41 to 50 years
E	50 years and older

Table 50: Criteria for Failure Rates

Condition Rating	Corresponding Condition
A	Less than 0.5 Failure per 10 km per year
B	More than 0.5 and up to 1.0 failure per 10 km per year
C	More than 1.0 and up to 2.0 failures per 10 km per year, cable is deteriorating

Condition Rating	Corresponding Condition
D	More than 2.0 and up to 4.0 failures per 10 km per year, cable is close to end-of-life, plan replacement
E	More than 4.0 failures per 10 km per year, cable is at end-of-life, replacement needed

Table 51: Criteria for Loading History

Condition Rating	Corresponding Condition
A	Typical Peak load less than 50% of its rating
B	Typical Peak load of 50% to 75% of its rating
C	Typical Peak load of 75% to 100% of its rating
D	Typical Peak load of 100% to 125% of its rating
E	Typical Peak load greater than 125% of its rating

A.5. Switchgears

Table 52: Criteria for Enclosure Condition

Condition Rating	Corresponding Condition
A	No signs of rust on the tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
B	Minor signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents

Condition Rating	Corresponding Condition
C	Significant signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
D	Major signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
E	Serious signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents

Table 53: Criteria for Condition of Interphase Barriers

Condition Rating	Corresponding Condition
A	No signs of damage or cracks in the interphase barriers
B	Signs of minor damage or cracks in the interphase barriers
C	Signs of significant damage or cracks in the interphase barriers
D	Signs of serious damage or cracks in the interphase barriers
E	Signs of very serious damage or cracks in the interphase barriers

Table 54: Criteria for Condition of Pad

Condition Rating	Corresponding Condition
A	Good condition as new
B	Normal sign of wear
C	Significant sign of wear

Condition Rating	Corresponding Condition
D	Poor condition, remedial action required
E	Immediate replacement required

Table 55: 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

A.6. Junction Boxes

Table 56: Criteria for Enclosure Condition

Condition Rating	Corresponding Condition
A	No signs of rust on the tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
B	Minor signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
C	Significant signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents

Condition Rating	Corresponding Condition
D	Major signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
E	Serious signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents

Table 57: Criteria for Condition of Pad

Condition Rating	Corresponding Condition
A	Good condition as new
B	Normal sign of wear
C	Significant sign of wear
D	Poor condition, remedial action required
E	Immediate replacement required

Table 58: 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

Condition Rating	Corresponding Condition
E	41 years or older

A.7. Pole-Mounted Transformers

Table 59: 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

Table 60: Criteria for Infrared Scan

Condition Rating	Corresponding Condition
A	No hot spots detected
C	Noticeable hot spots detected, but they do not jeopardize safe on-going operation.
E	Very Serious hot spots detected

Table 61: Criteria for Condition of Tank

Condition Rating	Corresponding Condition
A	No signs of corrosion
B	Less than 0.5mm in diameter corrosion that cover less than 1% of the equipment surface area. Presence of paint bubbles or metal pitting.
C	Corrosion that are approximately 0.5 mm in diameter that covers 1% - 5% of the equipment surface area. Signs of red, black or white corrosion, pitting of surface.
D	Corrosion between 0.5 mm to 5 mm that covers less than 6% - 25% of the equipment. Signs of small pin holes.
E	Corrosion that are greater than 5 mm and covers more than 25% of the equipment surface area. Metal has been penetrated through over large area.

Table 62: Criteria for Condition of Bushing

Condition Rating	Corresponding Condition
A	Bushings are free of chips, radial cracks, flashover burns, contamination with copper splash. Cementing and fasteners are secure.
B	Bushings are not cracked, however there are some minor chips which can be repaired by paint or insulating varnish to fully restore glossy finish. No flashover burns or contamination with copper splash. Cementing and fasteners are secure.
C	Bushings are not cracked; however, there are significantly large chips or flashover burns which can be repaired to partially restore glossy finish. Cementing and fasteners are secure.