BLUEWATER POWER DISTRIBUTION CORPORATION

DISTRIBUTION SYSTEM PLAN
2023-2027

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INTRODUCTION

Bluewater Power Distribution Corporation (“Bluewater”) is a Local Distribution Company (“LDC”), which has delivered electricity to the people of the Sarnia-Lambton area for over 100 years. It serves approximately 37,000 customers in the communities of Sarnia, Petrolia, Point Edward, Warwick Township (Watford), Brooke-Alvinston, and Oil Springs. To provide these services Bluewater operates and maintains over 1,200 km of electricity line, covering over 200 sq. km of service territory.

Bluewater’s most recent Cost of Service filing was EB-2012-0107 for rates effective May 1, 2013. This filing did not include a Distribution System Plan (“DSP”), as it was not required at that time. As such, this is Bluewater’s first DSP.

The main focus of Bluewater’s DSP is maintaining the assets that make up the distribution system and improving reliability. This DSP outlines the strategy in place to ensure the customers of Bluewater continue to receive their desired level of customer service, safety, and reliability at a competitive price. It takes a long range view of asset ages and condition, considers expected changes to the distribution system, and incorporates feedback from customers to shape a plan that will meet customer expectations today and into the future.

A challenge facing Bluewater’s system today is that large parts of its service area were built during a rapid “boom time” in the 1960s and 1970s, meaning much of the electrical infrastructure is currently deteriorating near its end of life. Bluewater retained Kinectrics Inc. (“Kinectrics”) to complete an Asset Condition Assessment (“ACA”) study, which analyses Bluewater’s distribution assets and provided input into the development of this DSP.

Another challenge that Bluewater faces is low customer growth and decreasing consumption. Between 2013 and 2021, Bluewater’s service area has seen a 2.89% growth in the number of metered customer accounts (compound annual growth rate “CAGR” of 0.36%). Consumption (kWh) over the same time period has decreased by 4.8% (CAGR -0.61%), and demand (kW) has decreased by 10.27% (CAGR -1.35%). This decrease in consumption and demand is due to the combination of effective conservation and demand management (“CDM”) efforts, as well as economic and environmental drivers that have impacted the industrial and commercial sectors in the Sarnia area, particularly since the economic downturn starting in 2008. Hydro One and the Independent Electricity System Operator (“IESO”) are confident there is sufficient capacity in their supply to this area, based on the Regional Planning Process.

Despite decreasing consumption and low customer growth, Bluewater is receiving increased customer requests for subdivision work and upgrades, which are budgeted under the New Connections, Upgrades, Subdivisions budget (UT11). In recent years, there has been a change in the nature of subdivision development. Where subdivisions would historically have been developed in phases, developers are now requesting entire subdivisions be developed at once. While the optimistic outlook of the developers may suggest that increased customer growth may occur in the future, Bluewater’s customer count remains relatively stagnant. Between January and September 2022, there was a 0.42% increase to the number of residential customers.

To continue to find efficiencies and overall improvements in the distribution system and customer experience, Bluewater plans to invest in replacing deteriorating assets, modernizing the grid, maintaining the fleet and facilities, and upgrading information technology. Bluewater’s Capital Expenditure Plan has been divided into the four investment categories identified in the OEB’s Chapter 5 Filing Requirements: System Access, System Renewal, System Service, and General Plant. These categories are used throughout the DSP.

The average forecasted overall capital spending per year between 2023 and 2027 will be approximately 36% higher than the average historical spending per year between 2017 and 2021. This is driven by system needs and is affected by inflation.

The distribution system in 2027 is expected to be similar to what it is today with the overall health of the system’s assets maintained with some technological improvement allowing for enhanced monitoring, control, and performance, as the system is modernized with more intelligent devices and systems.

This DSP is being filed in conjunction with Bluewater’s 2023 Cost of Service Rate Application.

5.2 DISTRIBUTION SYSTEM PLANS

Bluewater has prepared this DSP following the OEB Chapter 5 headings and section numbers in the order they are presented in Chapter 5 (April 2022 revision).

5.2.1 Distribution System Plan Overview

5.2.1.1 Overview – Key Elements

Throughout this DSP, Bluewater plans to achieve the following objectives, which are integral to the Bluewater Business Plan:

1. Safety First
2. Improve reliability
3. Maintain the condition of distribution system assets
4. Maximizing useful life of assets while minimizing lifecycle costs
5. Control Cost through Economies of Scope
6. Innovation

Guided by the above, Bluewater plans to replace deteriorating infrastructure in the distribution system in order to maintain the overall condition of distribution system assets and improve reliability.

A summary of Bluewater's proposed capital investments for the forecast period can be found in Table 1.

Table 1: Forecast Capital Expenditures ($'000)

OEB Investment Category	2023	2024	2025	2026	2027
System Access	2,322	2,446	2,520	2,595	2,642
System Renewal	6,659	5,900	5,244	5,401	5,520
System Service	514	194	200	206	211
General Plant	2,877	3,170	3,630	3,903	4,257
Total Expenditure	**12,372**	**11,710**	**11,593**	**12,105**	**12,631**
Capital Contributions	1,000	1,000	1,000	1,000	1,000
Net Capital Expenditures	**11,372**	**10,710**	**10,593**	**11,105**	**11,631**

System Access: 2023 Budget $2,322,000

System Access investments are driven by mandated service obligations such as new connections or upgrades and street widening. Investments in System Access stimulates economic growth with new subdivisions and road improvements.

System Access investments have comprised of 17% of the spending historically between 2013 and 2021, and is budgeted to represent 21% of spending in the forecast between 2023 and 2027. Due to a growth in subdivision plans, the budget for New Connections, Upgrades, Subdivisions (see Appendix F) has grown as compared to the historical period.

Key System Access projects address:

- New connections, commercial upgrades and connections, and development work
- Metering for new connections
- Street widening, requiring moving infrastructure

System Renewal: 2023 Budget $6,659,200

System Renewal investments allow for equipment that is better able to withstand weather events and decrease the chance of outages, as well as the modernization of end-of-life assets.

System Renewal investments represent almost half (48%) of the forecast total capital expenditures over the next five years (2023-2027). A large portion of the budget towards replacing deteriorating infrastructure is related to the Wood Pole Replacement Project. Spending on wood pole replacement has increased almost ten-fold when compared to the 2013 budget, and Bluewater expects the current level of spending on wood pole replacement will remain roughly the same for the foreseeable future. This increase in System Renewal spending, particularly on pole replacements, has been necessitated by deteriorating assets.

Since 2014, Bluewater has retained Kinectrics Inc. (“Kinectrics”) to perform an annual Asset Condition Assessment (“ACA”) on Bluewater’s key distribution assets. Kinectrics confirmed that Bluewater needed to increase spending in order to maintain the distribution system. In response, Bluewater increased its testing and replacement of distribution assets. In particular, it increased visual and physical pole testing (using hammer tests to determine strength) and later resistograph testing, which resulted in increased replacements.

Bluewater has reached a level of spending on System Renewal projects that is sustainable to maintain the distribution system.

Key System Renewal projects address:

- Wood pole replacements
- 4 kV system upgrades
- 8 kV load conversion to 27.6 kV in Sarnia
- Primary underground cable replacement

System Service: 2023 Budget $514,400

Investments in System Service will help Bluewater meet future power needs of Bluewater's customers more easily and ensure a reliable system, minimizing the number and duration of outages.

Investments in System Service represent the smallest portion of capital spending (6% historically and 2% in the forecast). The main drivers are operational objectives, including safety and reliability. Investments in the forecast period are primarily driven by new remote switches, including communication devices. However, modernization is also built into other projects which fall under other categories such as 27.6 kV Feeder Extension and 4 kV System Upgrades (see Appendix F).

Key System Service projects address:

- Telecommunications for communication between SCADA and 4 kV stations
- More automation
- More mapping tools to identify alternate paths for power during outages
- Remote switches that allow power to be redirected from the office
- Upgrades to systems to reduce power losses
- Animal protection

General Plant: 2023 Budget $2,876,500

Investments in General Plant allow for a well-maintained fleet that can respond to outages and emergencies, as well as technology to benefit the system and its customers.

General Plant investments made up 31% of the historical spending and 30% of the forecast. Large vehicle replacements continue according to Bluewater's vehicle replacement plan, while computer system needs (hardware and software) continue to evolve to meet changing customer expectations regarding the availability and format of information, and new tools are required to assist with monitoring and managing the distribution system.

Key General Plant projects address:

- Vehicle replacements
- Service Centre upgrades
- Information Technology – cyber security, customer information system, billing system, purchasing and finance systems

5.2.1.2 Addressing Customers' Preferences and Expectations

Bluewater encourages customer engagement and feedback through its day-to-day operations. Bluewater welcomes customer walk-ins at its accessible office. Front-counter staffing is maintained during regular business hours, which allows for valuable, daily, one-on-one engagement with customers. Bluewater also answers all its telephone calls in-house, allowing for local employee representation and swift resolutions to customer issues.

Bluewater is proud to serve its communities and provide exceptional, local, 'home-town' service. Bluewater regularly attends local events to engage its customers.

In addition to its consistent engagement through regular business activities, Bluewater also conducts major initiatives to further optimize feedback. Examples of such special initiatives include online and telephone Customer Satisfaction Surveys and Customer Focus Group meetings. Bluewater also gathers survey feedback at community events to encourage meaningful and measurable feedback.

In early 2022, Bluewater initiated an online survey to solicit customers' preferences and expectations, as well as educate customers and gain feedback on this DSP. A virtual meeting was conducted to further engage directly with Bluewater's Large and Intermediate customers. Throughout the consultation processes, customers provided suggestions on how Bluewater could improve its service.

The results of these engagements, as detailed in Exhibit 1 of Bluewater's 2023 Rate Application, provided direction to Bluewater in the preparation of this DSP. Affordable cost of electricity and reliability were the top priorities for most customers. This DSP outlines Bluewater's approach to address customer priorities, including delivering reliable and cost-effective service.

Customers also made it clear that they value reduced response time to outages and improved technology to enhance the electrical system. To meet customer expectations, Bluewater will continue to integrate a Fault Location, Isolation and Service Restoration system ("FLISR", formerly FDIR), which will leverage the existing outage management system ("OMS") to provide better data on the location of outages and restoration. The FLISR system also acts automatically to switch around system faults to bring as many customers as possible back online in the shortest possible timeframe.

Furthermore, customers value outage-related communications. In 2015, Bluewater introduced a social media presence that provides customers with important and timely information about their electricity services. Social media is monitored 24/7 by in-house staff, and the channels allow for prompt two-way communication. Bluewater informs and interacts with customers to keep them aware of both planned and unplanned outages, storm management, regulatory changes, general safety, and customer planning information.

Examples of social media engagement efforts include general educational posts: how to read a hydro bill and updates for changing Time of Use periods. The education component aims to inform customers about services that are currently offered, as other forms of engagement have confirmed that customers often request services that are already offered. Posts also provide alerts regarding outages and storms, as well as safety tips on outage preparation, power restoration, downed wires and Ontario OneCall. Social media communication is also successful at highlighting Bluewater's community involvement, project updates, and sharing success stories. The Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application details further activities.

As with many LDCs, Bluewater provides online tools and account access with MyAccount. These tools allow for a variety of self-serve options and access to information. As of July 2022, approximately 27,000 customers have signed up for MyAccount. On average, 7,800 customers use MyAccount each month. Bluewater will initiate improvements to these services through technology development and customer direction.

5.2.1.3 Sources of Cost Savings

Bluewater plans to contain the cost of asset replacement by focusing spending on the assets most at risk of failing and adversely impacting customers, as identified in the ACA report (see Appendix A – Asset Condition Assessment (ACA) Report).

For overall cost efficiencies, Bluewater will continue to utilize affiliate companies to find economies. For example, Customer Service serves both electricity and water customers; as a result, the costs of the billing system, phones, general software, and staff are shared with Bluewater Power Services Corporation.

Voltage conversions and the elimination of MS substation through conversion to 27.6 kV

Voltage conversions will take place as assets are replaced, when it fits with the overall system plan. This will decrease system losses over time. Voltage conversions can also increase the capacity of feeder cables, resulting in fewer circuits supplying the same load. There are fourteen 4 kV substations and one 8 kV substation in Bluewater's service area.

To date, Bluewater has eliminated three 4 kV substations and two 8 kV substations. The 27.6 kV Feeder Extensions and 8 kV Load Conversion projects will eliminate the last 8 kV substation (Municipal Substation "MS" 21) in Bluewater's distribution system. The related system connected to MS 21 will be converted to 27.6 kV. The elimination of MS 21 will improve reliability and eliminate the ongoing maintenance of this substation and the costs associated with it, as well as improve savings from line losses.

Tree trimming and vegetation management

The preventative practice of vegetation management and tree trimming is performed on the overhead distribution system in both urban and rural areas on a four-year cycle.

Bluewater increased tree trimming clearances around its St. Andrews transformer station in 2021 due to reliability concerns for large customers and a large number of dead ash trees. The implementation of this program addressed customers' reliability issues without requiring upgrades to the substation and further capital spending. The increased clearance should reduce outages and related storm costs.

Standardized designs

Bluewater is a member of the Utilities Standards Forum ("USF"), an organization owned by 53 Ontario electricity distributor members. Bluewater actively participates in the Engineering, Regulatory, and Customer Service and IT forums, where members share best practices and troubleshoot common challenges. USF initiatives provide improvements to compliance, system reliability, and overall process costs.

Through this association, Bluewater shares common intellectual property, responses to industry and regulatory requirements, and introductions to vendors for bulk purchasing. Bluewater has access to standardized designs and templates, which reduces the resource requirements of project designs. Bluewater uses USF standards for the majority of its designs and supplements with its previously approved standards, where necessary.

Distribution recloser installations

Bluewater installs re-closers to improve reliability, as part of a self-healing grid. Previously, employees attended onsite to reclose, but this can now be performed from the control room or automatically via the FLISR (Fault Location, Isolation, and Service Restoration), which is part of the Supervisory Control and Data Acquisition ("SCADA") system.

There are currently 18 reclosers in Bluewater's service territory, which will reduce truck-rolls for locating the outage source. This in turn reduces operational costs associated with outage restoration.

Geographic Information System ("GIS")

Bluewater uses GIS to track the age, location, and status of distribution assets in service. This reduces costs by minimizing the need to send resources onsite to field-verify existing asset conditions.

GIS also allows for cost reduction to asset condition studies. Data is pulled from GIS, reducing the need for employees to attend onsite for the purposes of these studies.

Thermographic Infrared Inspection

Infrared thermography, a predictive maintenance practice, is performed on an annual basis by a contracted party with qualifications in this imaging technique. This non-destructive, non-invasive procedure measures temperatures across surrounding components of distribution assets, allowing for visualization of deficiencies prior to failure.

Infrared thermography is performed primarily on three-phase feeders on the overhead distribution system, but may also include single phase lines where the cause of a fault is unidentified. Thermographic imaging is also performed on switches, pothead terminations, lightning arrestors, clamp assemblies, transformers and bushings, terminal connections and conductors. Images of the deficiency, visible as a temperature variance and commonly referred to as "hot spots", are captured and included within a report prepared by the contractor.

Bluewater conducts thermographic infrared inspections to avoid sudden, complete equipment failures. Reduced asset performance and continued deterioration may be mitigated or avoided with such inspections, reducing emergency and overtime work and improving reliability as a result.

Vault Inspections

Vault inspections, a form of a predictive maintenance practice, are performed on a monthly basis throughout the entire distribution system. During the inspection, vaults are assessed for water level, debris accumulation, and general facility condition, such as operation of light bulbs and sump pumps. Additionally, vault security is assessed for damaged lids and locking mechanisms.

Bluewater endeavours to remediate smaller deficiencies or critical deficiencies (i.e. those presenting a hazard to health, safety or the environment) during the inspection. A work order is generally prepared for condition-based maintenance to remediate critical or high priority deficiencies. Larger or non-critical deficiencies identified during the inspection are documented and, subsequent to the inspection, compiled into a single work-order for scheduling of condition-based maintenance.

The inspection, testing, and condition-based maintenance of vaults avoids and reduces unexpected outages and extends the life of the assets, reducing associated costs.

Cross-Phase Testing

In the forecast period, Bluewater will continue to conduct Cross-phase analyses of poly phase meter installations. Cross-phase testing consists of connecting an accuracy-calibrated analyzer in parallel with a metering installation insitu to verify all the components are configured and working correctly, thereby confirming the metering and any billing factors in use are correct. Confirming metering accuracy avoids lost revenue due to billing errors. Inspection of the meters also identifies faulty equipment to allow for proactive replacement of the assets.

Sample Testing Process

Bluewater tests a representative sample of residential meters every 2 years, prior to the end of the seal period. Based on the results, the meters’ seal periods may be extended. This life extension reduces the operational and capital costs to change all of the meters at the end of their seal period.

Distribution Plant Life Extension and Reduced Replacement Cost

Bluewater’s philosophy is to extend the useful life of assets by deferring capital investments until maintenance is no longer economical. As documented in the Asset Condition Assessment (and Table 24), the replacement strategy for Bluewater’s key assets is reactive or a combination of reactive and proactive for all asset types except for MS Transformers, Circuit Breakers, and MS Pad Mounted Switch Gear.

Changes to building to reduce operating costs

In 2019, Bluewater commenced the replacement of the electric heat pump system in the office building that is reaching its end of life after approximately 20 years. Replacement costs for this system would have been prohibitive. Service centre costs were budgeted to complete this project. The system was replaced with a combination of electric heat pump and some natural gas heating, which will reduce operating costs.

The office building has also been retrofitted with LED lights to replace the T12 fluorescent lamps. This has resulted in both electricity savings and improved lighting levels.

Technology

Bluewater's OMS and outage map, published on Bluewater's website and shared via social media, has provided customers with more information about outages, such as areas affected, number of customers affected, cause, and expected time of restoration. This has reduced the level of calls received during major storm events, thereby reducing staff costs.

Since Bluewater's last filing, Bluewater has increased customer billing options with the introduction of paperless billing or e-billing. Our customers can now receive their bill electronically or via mail and pay with Pre-Authorized Payments (PAP), online via their banking institution, or by way of personal cheque. All of these functions are available with easy point and click functions within Bluewater's online MyAccount solution.

Bluewater has also commenced a strategy to manage the main components of its IT hardware and software infrastructure through internally developed resources, rather than rely on outside contractors. This strategy complements the decision to move toward continuous minor improvements to its existing SAP software, rather than periodic upgrades as newer versions of SAP are introduced.

Fleet

Bluewater has implemented a number of cost saving measures with regard to its fleet.

An agreement was negotiated with a single source supplier for automobile parts to secure preferential pricing and stock on all Bluewater's frequently used service parts and supplies. This ensures Bluewater receives parts on time and at the best price available.

Bluewater has implemented an in-house maintenance program on all small, light duty vehicles and most pieces of construction equipment, reducing outsourcing costs. A new hoist was installed at the end of 2018. In-house maintenance includes oil changes, tire rotations, hydraulic system services, construction equipment service, and repairs.
Bluewater has licensed its in-house facility with the Ministry of Transportation to be able to perform its own vehicle safety inspections and complete its own repairs.

A new lifting system was purchased, which is capable of lifting all of Bluewater's heavy-duty fleet trucks to make repairs and inspections easier, safer and, more thorough. These will also aid in future plans to bring large truck service in house.

Bluewater is in the process of investigating and scheduling special training with TSSA, Freightliner, and Canadian Utility Fleet Council, to better understand and service its fleet. Heavy duty vehicles require extra training and licensing due to their size, configuration, and attachments. Training will allow Bluewater to move additional services and maintenance in-house.

Bluewater has implemented GPS tracking on its fleet in the forecast period. The installation of GPS devices provides the real-time location of all Bluewater's trucks, allowing for quicker response times to calls, by identifying the closest vehicle. It also provides engine and odometer data for diagnostics and maintenance planning, as well as accident notifications.

5.2.1.4 DSP Period Covered

This DSP covers the historical period from 2013 (last Rebasing Year) to 2022 (Bridge Year) and the forecast period from 2023 (Test Year) to 2027.

Table 2: DSP Period Covered (2013-2027)

Historical Period									Bridge Year	Test Year	Forecast Period			
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027

5.2.1.5 Vintage of Information

Much of the DSP was developed in the first quarter of 2022, using data that was current up to the end of 2021 (such as ACA, reliability analysis, load forecast).

5.2.1.6 Changes Since Last Filing

Bluewater’s most recent Cost of Service filing was EB-2012-0107 for rates effective May 1, 2013, which did not include a Distribution System Plan, as it was not required at that time. Instead, an Asset Management Plan (“AMP”) was provided as part of that application, which was based on the AMS (Appendix B) that was created with the assistance of a third party (AESI). Since the 2013 filing, Bluewater has continued to improve the asset management process by addressing some of the data gaps identified by AESI and generally increasing the amount of data collected for each asset category.

Asset Condition Assessment

Since 2014, Bluewater has retained Kinectrics to perform an annual Asset Condition Assessment (“ACA”) on Bluewater’s key distribution assets. The current ACA Report, prepared in 2021, can be found at Appendix A.

The ACA Report includes a prioritized listing of assets “Flagged-for-Action” over 10 and 20 years. The ACA Report also identifies the quality of the data provided so that any remaining data gaps can be addressed during the next inspection and maintenance cycle.

By using a third party to provide the ACA Report, Bluewater has a more robust and independent assessment of the condition of its asset base and recommendations for repair or replacement. The annual ACA Report is used by Bluewater during the creation of the annual capital and maintenance budgets, as well as updates to the rolling five-year budget forecasts.

Customer Engagement

Customer preferences and feedback regarding asset performance are being incorporated into the overall process for creating the annual budgets and five-year forecast.

Pole Inspections

Since 2014, Bluewater has retained Kinectrics to perform an annual Asset Condition Assessment (“ACA”) on Bluewater’s key distribution assets. In response, Bluewater increased its visual and physical pole testing (using hammer tests to determine strength) resulting in increased replacements.

In 2017, Bluewater commenced a systematic approach to resistograph pole testing, with the intent to test 100% of the poles in a 10-to-15-year period in order to gain a baseline of data. Resistograph testing uses a piece of equipment which penetrates the pole at its base, measures its hardness and, by comparing that value to a known value for the species of wood pole, gives an estimate of useful life remaining.

Technology

Since the last filing, Bluewater developed Tally, a program for timesheet management. It was developed in-house and has had iterations of development such that it is now completely integrated with SAP for time and work order management. As well, it is mobile optimized and can be accessed on any internet connected device including company issued smart phones, tablets, and laptops. This has ensured the best available information for capital. It has also saved countless hours of manual data entry for employees, supervisors, and the Finance Team. Integration has been developed such that the manual and thus error-prone entries into the payroll system have been virtually eliminated.

Another example of IT improvements is with Requisitions-on-Demand, known as ROD. This is another in-house developed app that manages the front-end of supply chain. It is also mobile optimized and available to employees inside or outside the company. It has moved workflow of purchasing approvals to an automated system thereby reducing the time to purchase and acquire goods and services.

In 2019 and 2020, Bluewater implemented a new Operational Data Store (Utility Data Manager) along with Retail Settlement Variance Account Manager (RSVA). These tools are third-party “Software as a Service” solutions that expand the operational data store functions required for smart meter billing and management to include automation of various regulatory required functions such as retail and wholesale settlement, Form 1598, and statistical reporting for the OEB. Moving these functions to a single integrated and automated platform will save costs with respect to fees for services and will both reduce the time required to manage settlement and associated regulatory functions but will reduce potential errors of manual solutions.

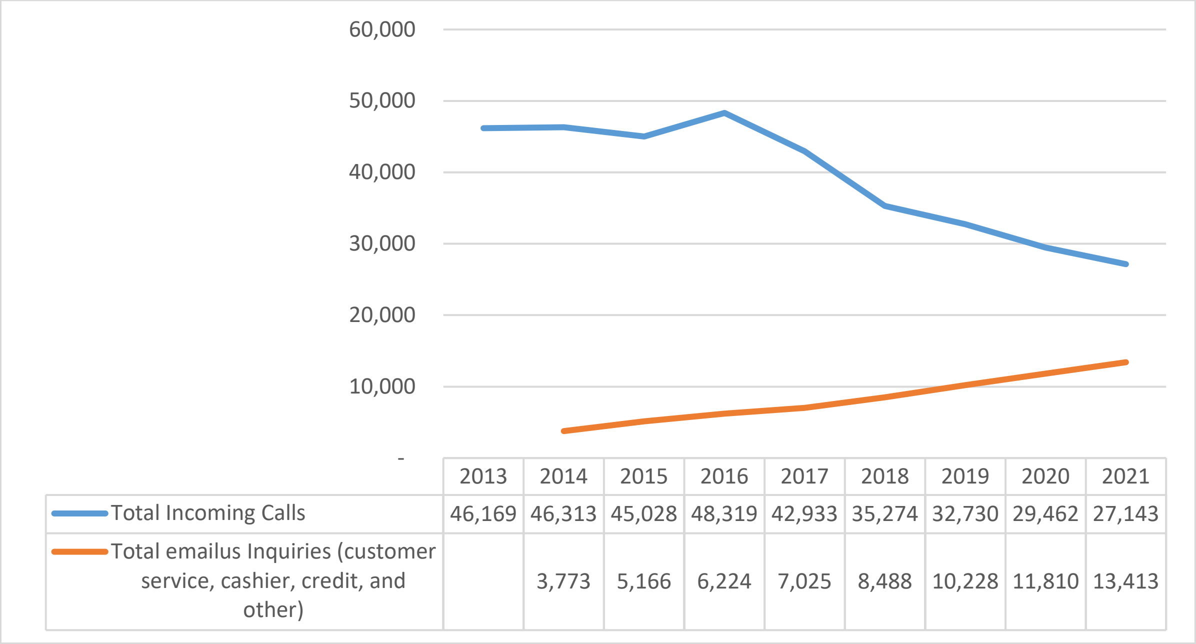
Bluewater implemented an Outage Management System (OMS) and Outage Map that is published on Bluewater’s website. This has provided customers with more information about outages and reduced the level of calls received during major storm events. This has enabled Bluewater to manage after-hours storm events with fewer call center staff (and thus less overtime).

Bluewater developed an automated alerting system that will inform key staff of an issue any time one particular transformer has meter outages that reach 10. This triggers staff to respond to the outage often before customers even call in about an outage.

In 2015, Bluewater introduced a social media presence that provides customers with important and timely information about their electricity services. Using Facebook and Twitter, Bluewater informs customers and keep them posted about both planned and unplanned outages, storm management, regulatory changes, and general safety and customer planning information. This may have contributed to reduction of the number of calls into Bluewater’s Customer Service group, has enabled Bluewater to get information out to masses of people instantly, and has served to increase positive customer relations. Bluewater tracks the usage on its social media platforms; the growth is shown in Figure 2, which demonstrates increases from 2020 to 2021.

The number of calls into Bluewater’s Customer Service group were 41% lower in 2021 than in 2013, with a notable decline between 2016 (the year after social media presence was commenced) and 2021 of 44%. Bluewater does find that the decrease in number of phone calls is partially offset with an increase in customer requests for information via email.

Figure 1: Total Qualified Incoming Calls

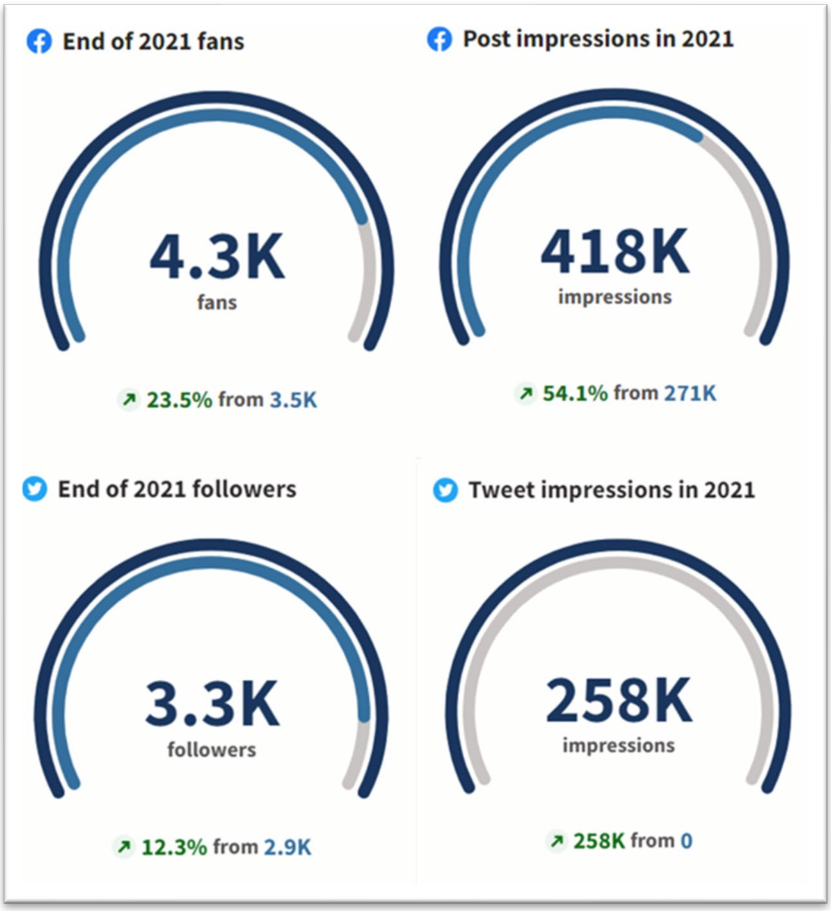


	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Incoming Calls	46,169	46,313	45,028	48,319	42,933	35,274	32,730	29,462	27,143
Total emailus Inquiries (customer service, cashier, credit, and other)		3,773	5,166	6,224	7,025	8,488	10,228	11,810	13,413

Furthermore, Bluewater has enhanced its website to allow more forms to be completed by customers online. This includes:

- Start service
- Stop service
- Requesting new service
- Reporting streetlight outage
- Request tree trimming
- Changing from Time of Use (“TOU”) to Tired rates and vice versa

Figure 2: Social Media Impressions (2020 versus 2021)



As mentioned above, Bluewater has increased customer billing options with the introduction of paperless billing or e-billing. Paperless billing reduces costs by almost $1 per bill, which creates operation expense reductions. As of January 2022, 34% of Bluewater's invoices are e-billed. Bluewater will continue to encourage adoption of Paperless Billing through various campaigns.

In 2016, Bluewater began looking at document management solutions. At the time, Bluewater had a manual Central File process that was cumbersome, costly, and difficult to negotiate. Because of that, many documents that should have been centrally managed were being stored in decentralized and often independent manners. It became clear that Bluewater needed a solution that would be effective and used by staff. After reviewing a number of commercial products, it was determined that a lower cost solution could be developed in-house that would meet Bluewater's needs. In 2018, an in-house archival software was developed, known as ARC. This web-based document management solution is now live, and Bluewater is working to digitize its files.

5.2.1.7 Contingent Aspects

Some aspects of this DSP are contingent on events beyond the control of Bluewater. As with all distributors, the volume and cost of customer-driven work (such as new and upgraded connections and asset relocations to accommodate municipal projects) will vary from year to year due to fluctuations in the local and national economy. Bluewater works closely with the local municipalities to stay current on plans for municipal projects, recent housing trends, and potential commercial and industrial activity that could result in changes to the forecast for customer connections and upgrades.

As noted in Section 5.2.2 b, the Regional Planning did not identify any assets that need to be upgraded or enhanced to address any capacity issues. Regional Planning identified sustainment projects which include the replacement of the St. Andrews TS in 2025. The new station will have a higher Limited Time Rating, resulting in greater capacity of 120 MVA in summer months and 133 MVA in winter months. At this point, Hydro One has not indicated that this project will require a capital contribution from Bluewater. This may change as the actual scope of the project is developed by Hydro One and Bluewater is made aware of any optional investment opportunities that may improve the system reliability for Bluewater customers.

5.2.1.8 Grid Modernization, DER, Climate Change, and LTEP

Bluewater’s last cost of service application included a Green Energy Act Plan which proposed $40,000 in expenditures annually, over a 4 year period for a total of $160,000. At that time, Bluewater estimated that collaborative research would cost approximately $35,000 per year and staff training and education would cost approximately $5,000 per year. At that time, Bluewater had not finalized any plans related to smart grid capital projects.

Subsequent to that application, Bluewater made two key investments to modernize its grid that qualify for Smart Grid treatment, as outlined below. Bluewater had not filed a cost of service application with a DSP and therefore have reported these investments in Account 1534 – Smart Grid Capital Deferral Account. With the submission of this DSP, Bluewater has included future smart grid expenditures and will no longer utilize the deferral Account.

1. Distributed Transformer Monitoring: Distribution transformer monitoring devices provide real-time data for each transformer fitted with a device. Information such as energy theft detection, transformer loading information, and distributed generation and electric vehicle charging impacts can be analyzed. In its first year in 2015, Bluewater purchased 5 single-phase units. They were installed at strategic locations in order to gather the data and determine the best use of the data. Later in 2015, 2016, and 2018, an additional 17 single phase units were purchased, as well as 8 poly-phase units. The data continues to be assessed; however, Bluewater has concluded that in order to be highly effective, these monitoring devices would have to be installed at every transformer rather than sporadically through the service territory.

   Bluewater decided to purchase and install additional poly-phase devices to be installed on three phase transformers that are located inside the vaults located in Downtown Sarnia. As these transformers are not easily accessible and the Downtown is being re-vitalized with on-going improvements (new commercial services, new apartments, etc.), it was decided that it would be an ideal location to monitor the ever-changing transformer loading on these transformers.

   In regard to the LTEP, Distributed Transformer Monitoring will assist in load management by having a view into the transformers that are being evaluated. This will help assess loading if the take-up on electric vehicles increases in this service area for example, and by having monitoring abilities will add flexibility to the energy system consistent with the LTEP.

2. Distribution Automation - FLISR (Fault Location, Isolation, Service Restoration): FLISR (formerly FDIR) is a software system that will improve operational efficiency and reduce the duration and size of large outages. As more remotely operated switches are added, this efficiency will increase.

   FLISR is a natural extension of the existing Supervisory Control and Data Acquisition (“SCADA”) system. Bluewater has been using SCADA for more than 20 years, so it has developed internal expertise with the use of the platform into which FLISR is integrated. FLISR, once in fully automatic mode, will reduce the number of customers affected when a fault occurs. It will reduce the duration of an outage by enabling Bluewater’s operators to focus their efforts on correcting the fault, as the detection, isolation, and restoration is done automatically. It will further improve the efficiency of the line crew.

As safety is an ongoing concern for Bluewater's employees and the general public, FLISR is an ideal solution, as it is integrated with SCADA. SCADA manages lock-outs, switching orders, and tags and would continue to do so. This gives FLISR direct access to the current status of Bluewater's grid, which allows it to make safe decisions when closing and opening remotely operated equipment. Initially, it was run in semi-automatic mode until Bluewater's Operators validated the safety and proposed operations of the system

Our long-term plant management strategy includes adding remotely operated switches yearly for the foreseeable future; FLISR will leverage and improve the efficiency of the use of these devices. Bluewater initially launched with 13 remotely-operated switches and have since added an additional 5 switches. Bluewater has budgeted to install 2 remote switches per year under the Remote Load Break Switches project (UT25).

Smart Grid technology, such as FLISR, can greatly improve the customer experience and Bluewater's operational efficiency.

Currently, FLISR is fully active on some of the circuits and in semi-auto on other circuits. The Bluewater Control Room is monitoring the performance and building on their experiences in order to fully develop switching schemes in order to fully automate this process.

In regard to LTEP, FLISR will improve value and performance for customers by reducing the number of customers affected by outages, and will also reduce the duration of the outages.

Smart Grid Expenditures

The following table provides the breakdown and timing of capital expenses for these projects.

Table 3: Smart Grid Capital Projects

Project	2015	2016	2017	2018	2019	2020	2021	Total ($)
Distribution Automation (FDIR)	216,577	5,298						221,875
Scada Monitoring Devices	27,484	19,285		2,569		5,360	2,272	56,970
Total	**244,061**	**24,583**		**2,569**		**5,360**	**2,272**	**278,845**

Since 2013, Bluewater has spent approximately $463,000 in capital and O&M expenses on the Smart Grid initiatives. The majority of the spending has been on capital, with approximately $217,000 being spent on the FLISR (formerly FDIR) software implementation in 2015. Bluewater has booked these costs to the OEB-approved deferral accounts 1534 and 1535, which Bluewater is requesting disposition of in this rebasing application. The amount in the deferral account is calculated in Exhibit 9.

Under Smart Grid OM&A, Bluewater contributed research projects at a total cost of $93,450 and completed employee education and training for a total amount of $20,222. The research projects included the following:

- Lambton College - Partnership contribution FEDDEV II: $5,000.
- Smart Management and Control of Short Circuit Currents to Increase Connectivity of Renewable Sources in Transmission and Distribution Grids of Ontario – University of Western Ontario: $18,540
- Lambton College & University of Calgary - Optimal Planning and Operation of Micro grids: $45,000
- Screaming Power – Mobile Cloud App: $25,000

In addition, ongoing operating expenses for the capital projects completed (software support costs for FLISR (formerly FDIR) and data plan costs for the SCADA monitoring devices) totalled $70,636. Details and timing of the expenses are provided in Table 4 below:

Table 4: Smart Grid OM&A

Projects	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Research Projects	5,000	15,000	18,540	15,000	15,000	25,000					93,540
Employee Education and Training		16,722	1,000	1,250	1,250						20,222
FDIR - Software Support Costs						6,320	12,640	12,640	12,640	12,640	56,880
Scada Monitoring Devices - Data PlanGrid			1,228	1,939	1,584	1,787	1,719	1,879	1,810	1,810	13,756
Total	5,000	31,722	20,768	18,189	17,834	33,107	14,359	14,519	14,450	14,450	184,398

5.2.2 Coordinated Planning With Third Parties

5.2.2.1 Description of Third Party Consultations, Results of Consultations

Bluewater Customers

Purpose of Consultations

The purpose of consultations with customers is to measure satisfaction, determine needs and preferences, and identify opportunities to improve the customer experience. Customer engagement also serves as an opportunity to educate customers on Bluewater’s role in the provincial electricity system, its local distribution system, and the electricity bill, including e-billing.

Initiator

Bluewater initiates customer satisfaction surveys and focus groups. Feedback is also obtained when customers call or visit the Bluewater office in person, engage through social media, or at community events.

Other Participants

Oraclepoll Research conducts the biennial customer satisfaction and public safety surveys on behalf of Bluewater.

Deliverables – Scope and Timing

Bluewater engages with customers throughout the year in a variety of methods, which are detailed in the Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application.

Bluewater retained Oraclepoll Research to conduct telephone customer satisfaction surveys of residential and GS<50 kW customers in 2014, 2017, 2019, and 2021, as mandated by the OEB.

Oraclepoll Research submitted the final report for its most recent Customer Satisfaction Survey in March of 2021. Overall, 70% of residential and 66% of GS<50 kW customers indicated that they were satisfied with Bluewater. A copy of the 2021 report is attached in the Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application.

In the first quarter of 2022 Bluewater conducted online surveys, created and implemented in-house, and held a virtual Lunch and Learn to solicit customer engagement on its plans over the next 5 years. Further details may be found in the Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application.

Impact to DSP

The feedback provided by customers in the online surveys gave a clear direction to continue to focusing on capital projects to increase reliability and reduce response time to outages.

Regional Planning

Purpose of Consultations

In 2013, the Ontario Energy Board ("OEB") established the Regional Infrastructure Planning process, comprising of four major steps: Needs Assessment ("NA"); Scoping Assessment ("SA"); Integrated Regional Resource Planning ("IRRP"); and Regional Infrastructure Planning ("RIP"). The purpose of regional planning is to identify transmission capacity needs, system reliability needs, and load growth in the region.

The first cycle of regional planning included the Chatham-Kent/Lambton/Sarnia Region ("CKLS"), and a Needs Assessment was started in 2016 and in August 2017 a Regional Infrastructure Plan was completed.

The results of the 2017 NA noted that there were no identified Transmission Capacity Needs or System Reliability/Operation and Restoration Needs. Load growth in the Region and within the Bluewater service area was expected to be minor and not require additional capacity within the forecast period. Deteriorating infrastructure and replacement plans included the refurbishment of the existing Wanstead TS (which was converted from 115 kV to 230 kV) in 2018 and refurbishment of the existing St Andrews TS, planned for 2025, and the Scott TS refurbishment, planned for 2024. The recommendations noted here have since been updated in the 2021 NA as outlined below.

In accordance with the Regional Planning process, the planning cycle should be triggered at least every five years. In accordance with the mandate, the Needs Assessment for the 2nd Regional planning cycle for CKLS commenced in June 2021 and was completed on September 30, 2021 with the issuance of a Needs Assessment Report (“2021 NA”), filed as Appendix C.

Following the NA report, a Scoping Assessment Outcome Report (“SA”) was issued by the IESO in December 2021 and is filed as Appendix C. The SA considers three potential planning approaches for the region, including an Integrated Regional Resource Plan (“IRRP”) where both wires and non-wires options are considered; a Regional Infrastructure Plan (“RIP”) which considers wires-only options; or a Local Plan undertaken by the transmitter and affected LDC. The SA concluded that a RIP was warranted in order to address the capacity need in the Chatham-Kent sub-region.

The RIP is underway, and a final report is expected to be issued in the Fall of 2022. There are no inconsistencies between the DSP and any current regional plan.

Initiator

The NA and RIP phases are led by Hydro One being the lead transmitter in 21 regions, and the SA and IRRP (if needed) are led by IESO.

Other Participants

The study team for the CKLS included the following in Table 5.

Table 5: CKLS Study Team

Organizations
Hydro One Networks Inc. (Lead) Transmitter)
Independent Electricity System Operator
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

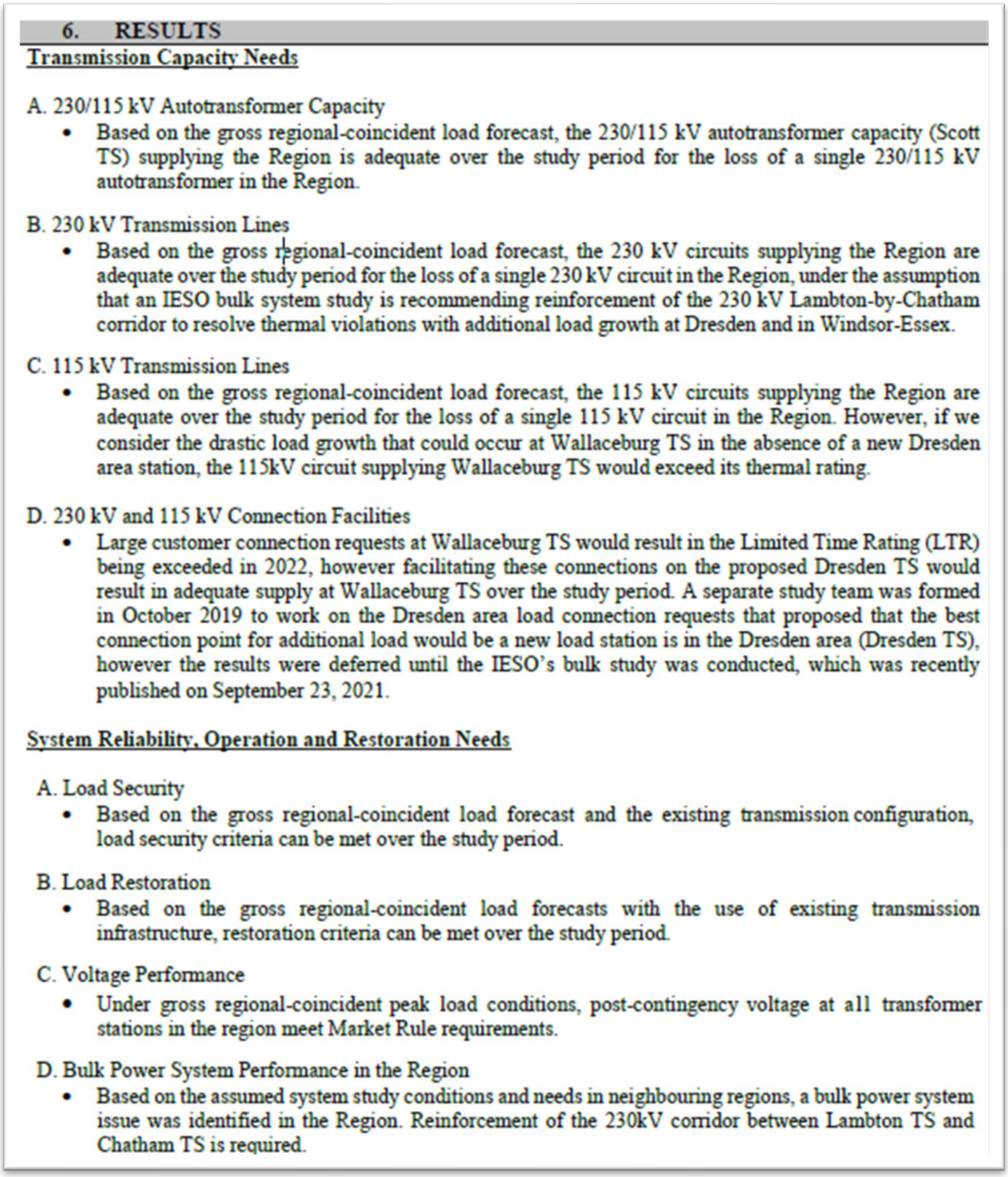
The SA also included feedback from the County of Lambton encompassing the City of Sarnia, and all of Bluewater's Municipal partners, Aamjiwnaang First Nations communities, and consumers.

Deliverables

The 2021 NA included the summary detailed in Figure 3 (and Appendix C, page 5), with a recommendation that regional planning is required to develop a plan to address the high demand for capacity near Wallaceburg TS as well as a plan to coordinate the connection of the proposed Dresden TS with bulk recommendations in the area. The Wallaceburg TS and the Dresden TS are both outside of Bluewater service territory.

The NA noted that within Bluewater's service area, St. Andrews TS is expected to approach and exceed its existing LTR in the medium-term (5-10 years), however, the planned like-for-like replacement of the transformers and switchyard (2025 in-service) will increase the station transformer's Limited Time Rating by 20 MVA and address the medium-term capacity need (Appendix C, page 1).

Figure 3: Summary of results of the 2021 Needs Assessment Report



6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformer Capacity

- Based on the gross regional-coincident load forecast, the 230/115 kV autotransformer capacity (Scott TS) supplying the Region is adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- Based on the gross regional-coincident load forecast, the 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region, under the assumption that an IESO bulk system study is recommending reinforcement of the 230 kV Lambton-by-Chatham corridor to resolve thermal violations with additional load growth at Dresden and in Windsor-Essex.

C. 115 kV Transmission Lines

- Based on the gross regional-coincident load forecast, the 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region. However, if we consider the drastic load growth that could occur at Wallaceburg TS in the absence of a new Dresden area station, the 115kV circuit supplying Wallaceburg TS would exceed its thermal rating.

D. 230 kV and 115 kV Connection Facilities

- Large customer connection requests at Wallaceburg TS would result in the Limited Time Rating (LTR) being exceeded in 2022, however facilitating these connections on the proposed Dresden TS would result in adequate supply at Wallaceburg TS over the study period. A separate study team was formed in October 2019 to work on the Dresden area load connection requests that proposed that the best connection point for additional load would be a new load station is in the Dresden area (Dresden TS), however the results were deferred until the IESO's bulk study was conducted, which was recently published on September 23, 2021.

System Reliability, Operation and Restoration Needs

A. Load Security

- Based on the gross regional-coincident load forecast and the existing transmission configuration, load security criteria can be met over the study period.

B. Load Restoration

- Based on the gross regional-coincident load forecasts with the use of existing transmission infrastructure, restoration criteria can be met over the study period.

C. Voltage Performance

- Under gross regional-coincident peak load conditions, post-contingency voltage at all transformer stations in the region meet Market Rule requirements.

D. Bulk Power System Performance in the Region

- Based on the assumed system study conditions and needs in neighbouring regions, a bulk power system issue was identified in the Region. Reinforcement of the 230kV corridor between Lambton TS and Chatham TS is required.

Upon completion of the NA in September 2021, a Scoping Assessment Report was completed by the IESO in December 2021. The SA incorporated consultation with Bluewater's Municipal partners, including the First Nations community of Aamjiwnaang First Nation. The engagement efforts identified that there may be additional load growth related to economic development, mainly attributed to vehicle electrification, development of a hydrogen hub in Sarnia-Lambton, as well as residential and industrial growth. However, it was noted that details of the magnitude and timing of this growth is uncertain (see Appendix D, page 12). As a result, the SA recommended that although there are no needs in the Sarnia-Lambton sub-region currently forecast to arise in the mid-term (5-10 years), the Working Group will continue to monitor growth in the region and re-evaluate these needs periodically, in order to trigger further regional planning for the Sarnia-Lambton sub-region as required (see Appendix D, page 13).

Finally, Regional Infrastructure Plan commenced in February 2022. The scope of the RIP includes any new information subsequent to the NA, a wires plan to address all the needs identified in the NA and recommendations from the IESO system studies. The RIP is expected to take approximately six months to complete, thus the end of August 2022 is the target.

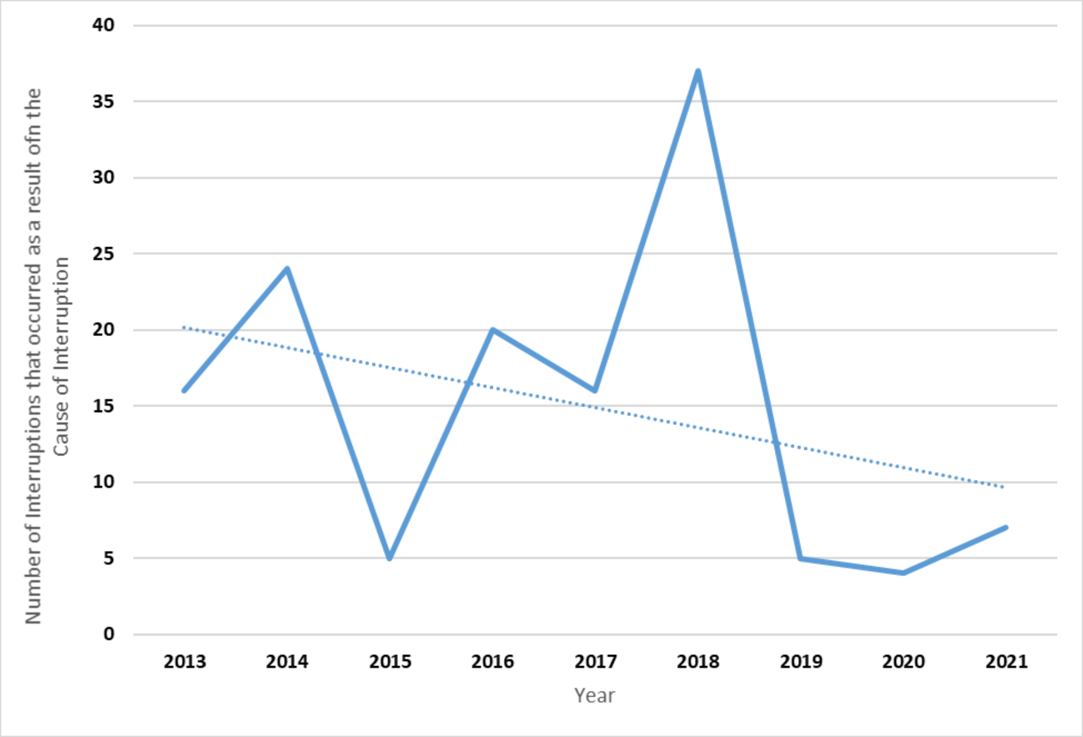
The main focus of the RIP is on the Wallaceburg and Dresden TSs in order to support the growth in that area. Bluewater does not anticipate any further changes to that noted in the NA.

Bluewater will provide updates to this section of the DSP should any proposed needs by identified in its service territory.

Impacts on DSP

The 2016/2017 Regional Plan included the conversion of the Wanstead TS from 115 kV to 230 kV, and that required a capital contribution from Bluewater of approximately $1.2 M total, made in annual payments from 2015 to 2018. The spending is included in the System Service Project UT67 Petrolia Wanstead TS (see Table 37). Bluewater has seen noticeable improvements in the reliability on the feeders that supply Bluewater’s municipalities of Petrolia, Oil Springs, Warwick and Brooke-Alvinston as can be seen in Figure 4, below.

Figure 4: Loss of Supply Outages - County



Bluewater does not expect any significant impacts on the DSP resulting from the 2021/2022 Regional Planning process as the load growth projected is expected to be met by the existing infrastructure, given the planned capacity increase in the St Andrews TS replacement planned for 2025.

Load Forecasting

Purpose of Consultations

The purpose of the consultations is to discuss load forecasting for the system. For local forecasting, developers and municipal planners are consulted during the early stages of projects to determine the power supply requirements.

Initiator

Hydro One initiates the load forecasting consultations on an as-needed basis. The last consultation was completed as part of the Regional Planning process just discussed.

Other Participants

Municipal planners and local developers participate in these consultations.

Deliverables – Scope and Timing

Hydro One-initiated load forecasting delivers Total Load for Bluewater per Delivery Point (see

Table 6 and

Table **7**), which is completed as part of Regional Planning.

Local consultations take place on a monthly basis with the Municipality and various consultants. Proposed projects and developments are reviewed. Anticipated load requirements are discussed with each consultant individually, as required for the particular project.

Impact to DSP

The DSP incorporates known impacts from projects that Bluewater is aware of. There have not been any major impacts to this DSP.

Utility Coordination Meetings

Purpose of Consultations

Bluewater participates in regular “joint trench” meetings with the local municipalities, other utilities (natural gas, telecommunication), and developers or consultants. These meetings facilitate the exchange of information regarding on-going and planned developments within the service area. The collaborative effort allows for cost-optimization such as sharing a common trench for utilities within residential and commercial subdivisions, as well as construction coordination (e.g. ensure all underground utility road crossings are complete before final paving).

Initiator

Local municipalities initiate these consultations.

Other Participants

Local utility providers, municipal representatives, and local developers participate in the meetings.

<u>Deliverables – Scope and Timing</u>

Multi-year forecast of major projects are provided involving most utility providers. Meetings occur on a monthly basis.

<u>Impact to DSP</u>

Utility Coordination Meetings allow for the forecast of circuit relocations.

Conservation, Demand Management, Distributed Generation Planning

<u>Purpose of Consultations</u>

Bluewater participated in the various CDM programs with assistance from third parties and Bluewater Power Services (affiliate of Bluewater). This includes various interactions with customers and their representatives. Distributed Generation Planning is done as part of Regional Planning and when requested by a specific customer / DG owner

<u>Initiator</u>

Bluewater initiated CDM/DG Planning consultations.

<u>Other Participants</u>

The IESO, other LDCs, Hydro One, Bluewater Power Services, and customers participate in these consultations.

<u>Deliverables – Scope and Timing</u>

An IESO Comment Letter was not required, because Bluewater has no REG investments during the 5-Year Distribution System Plan.

<u>Impact to DSP</u>

The CDM/DG Planning has not had an impact on this DSP, as the existing distribution system has adequate capacity to address foreseeable load and generation connections. Positive CDM results have contributed to declining load, which has also contributed to the reasons why the distribution system has adequate capacity.

Telecommunications Entities: Broadband Consultations

Purpose of Consultations

In accordance with *Ontario Regulation 842/21*, Bluewater consulted with telecommunications entities operating in Bluewater's service area for the purpose of facilitating the provision of telecommunications services that may require the use of or access to Bluewater's distribution infrastructure in order to attach wires, cables, or any other telecommunications facility, not including a wireless attachment.

Initiator

Bluewater initiated through written communication.

Other Participants

15 telecommunications entities were consulted

Deliverables – Scope and Timing

An email was sent to the telecommunications entitles on February 23, 2022. As of the date of filing this DSP, no telecommunications entities engaged with Bluewater concerning the provision of telecommunications services.

Impact to DSP

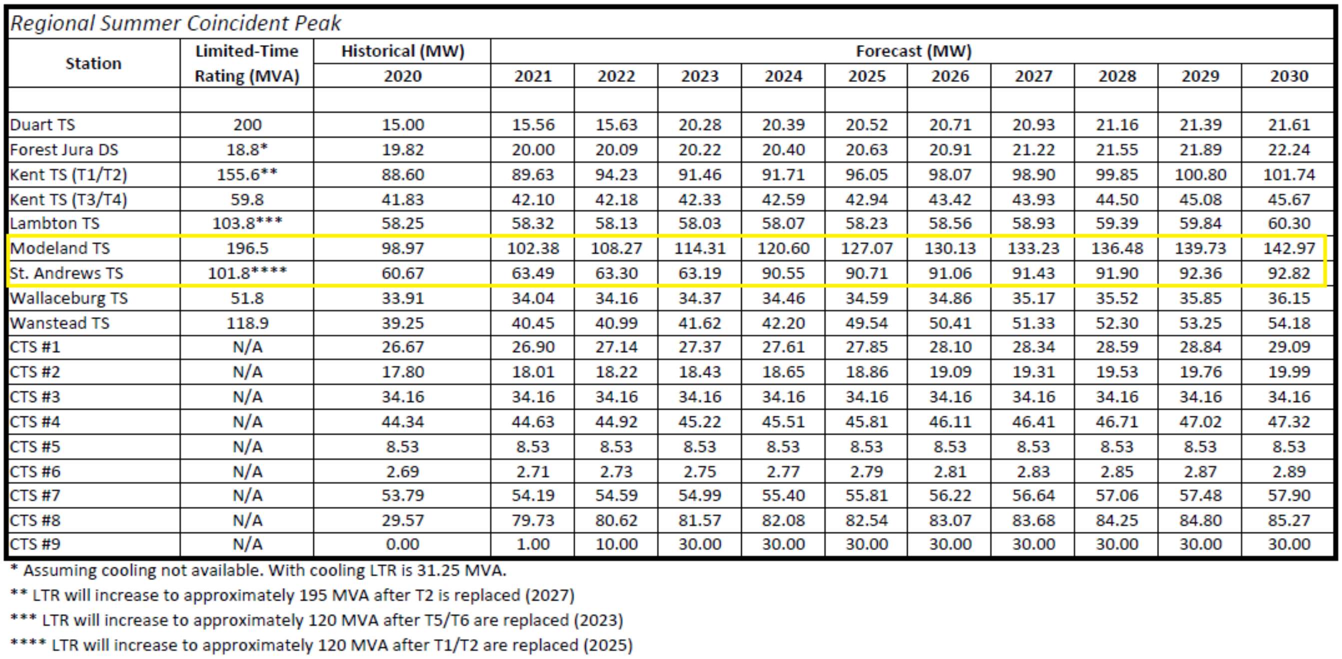
No telecommunications entitles responded to Bluewater's customer engagement, and there has been no impact to the DSP. Bluewater did, however, receive a "Data Sharing Notification" letter dated June 3, 2022 from Infrastructure Ontario.

5.2.2.2 Relevant Material Documents

The Needs Assessment Report, dated September 30, 2021 is included in Appendix C.

The following tables show the regional net coincidental and non-coincidental load forecasts. Modeland TS and ST. Andrews TS are highlighted.

Table 6: Chatham-Kent/Lambton/Sarnia Regional Net Coincidental Load Forecast

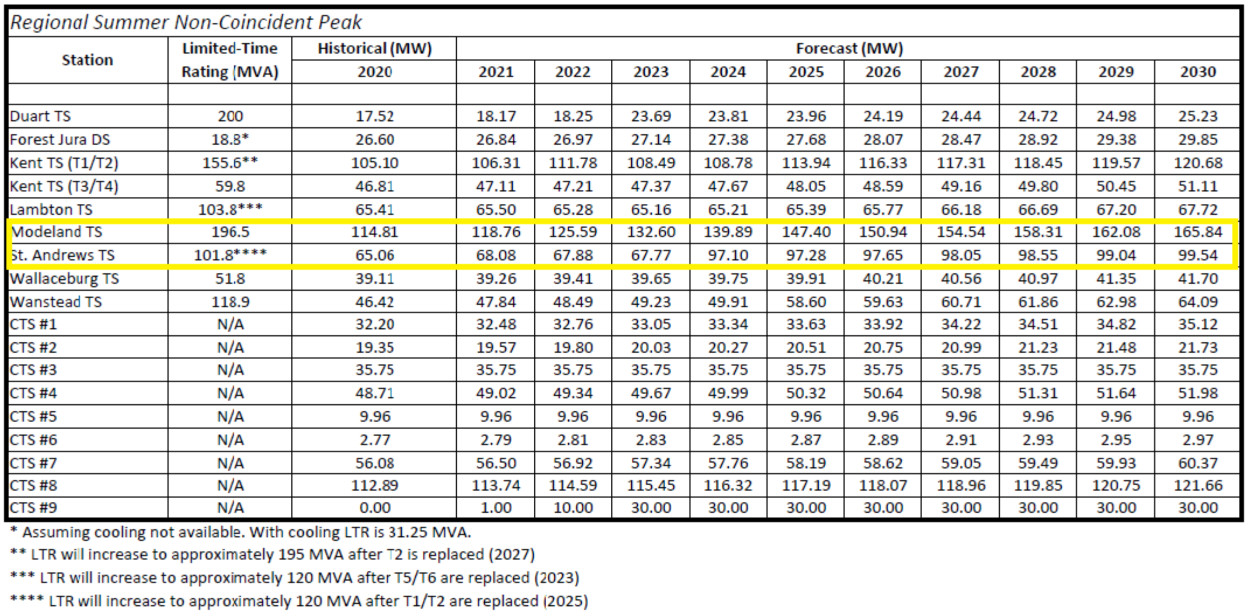


Regional Summer Coincident Peak

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	15.00	15.56	15.63	20.28	20.39	20.52	20.71	20.93	21.16	21.39	21.61
Forest Jura DS	18.8*	19.82	20.00	20.09	20.22	20.40	20.63	20.91	21.22	21.55	21.89	22.24
Kent TS (T1/T2)	155.6**	88.60	89.63	94.23	91.46	91.71	96.05	98.07	98.90	99.85	100.80	101.74
Kent TS (T3/T4)	59.8	41.83	42.10	42.18	42.33	42.59	42.94	43.42	43.93	44.50	45.08	45.67
Lambton TS	103.8***	58.25	58.32	58.13	58.03	58.07	58.23	58.56	58.93	59.39	59.84	60.30
Modeland TS	196.5	98.97	102.38	108.27	114.31	120.60	127.07	130.13	133.23	136.48	139.73	142.97
St. Andrews TS	101.8****	60.67	63.49	63.30	63.19	90.55	90.71	91.06	91.43	91.90	92.36	92.82
Wallaceburg TS	51.8	33.91	34.04	34.16	34.37	34.46	34.59	34.86	35.17	35.52	35.85	36.15
Wanstead TS	118.9	39.25	40.45	40.99	41.62	42.20	49.54	50.41	51.33	52.30	53.25	54.18
CTS #1	N/A	26.67	26.90	27.14	27.37	27.61	27.85	28.10	28.34	28.59	28.84	29.09
CTS #2	N/A	17.80	18.01	18.22	18.43	18.65	18.86	19.09	19.31	19.53	19.76	19.99
CTS #3	N/A	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16
CTS #4	N/A	44.34	44.63	44.92	45.22	45.51	45.81	46.11	46.41	46.71	47.02	47.32
CTS #5	N/A	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53
CTS #6	N/A	2.69	2.71	2.73	2.75	2.77	2.79	2.81	2.83	2.85	2.87	2.89
CTS #7	N/A	53.79	54.19	54.59	54.99	55.40	55.81	56.22	56.64	57.06	57.48	57.90
CTS #8	N/A	29.57	79.73	80.62	81.57	82.08	82.54	83.07	83.68	84.25	84.80	85.27
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* Assuming cooling not available. With cooling LTR is 31.25 MVA.
** LTR will increase to approximately 195 MVA after T2 is replaced (2027)
*** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)
**** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table 7: Chatham-Kent/Lambton/Sarnia Regional Net Non-Coincidental Load Forecast



Regional Summer Non-Coincident Peak

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	17.52	18.17	18.25	23.69	23.81	23.96	24.19	24.44	24.72	24.98	25.23
Forest Jura DS	18.8*	26.60	26.84	26.97	27.14	27.38	27.68	28.07	28.47	28.92	29.38	29.85
Kent TS (T1/T2)	155.6**	105.10	106.31	111.78	108.49	108.78	113.94	116.33	117.31	118.45	119.57	120.68
Kent TS (T3/T4)	59.8	46.81	47.11	47.21	47.37	47.67	48.05	48.59	49.16	49.80	50.45	51.11
Lambton TS	103.8***	65.41	65.50	65.28	65.16	65.21	65.39	65.77	66.18	66.69	67.20	67.72
Modeland TS	196.5	114.81	118.76	125.59	132.60	139.89	147.40	150.94	154.54	158.31	162.08	165.84
St. Andrews TS	101.8****	65.06	68.08	67.88	67.77	97.10	97.28	97.65	98.05	98.55	99.04	99.54
Wallaceburg TS	51.8	39.11	39.26	39.41	39.65	39.75	39.91	40.21	40.56	40.97	41.35	41.70
Wanstead TS	118.9	46.42	47.84	48.49	49.23	49.91	58.60	59.63	60.71	61.86	62.98	64.09
CTS #1	N/A	32.20	32.48	32.76	33.05	33.34	33.63	33.92	34.22	34.51	34.82	35.12
CTS #2	N/A	19.35	19.57	19.80	20.03	20.27	20.51	20.75	20.99	21.23	21.48	21.73
CTS #3	N/A	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75
CTS #4	N/A	48.71	49.02	49.34	49.67	49.99	50.32	50.64	50.98	51.31	51.64	51.98
CTS #5	N/A	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96
CTS #6	N/A	2.77	2.79	2.81	2.83	2.85	2.87	2.89	2.91	2.93	2.95	2.97
CTS #7	N/A	56.08	56.50	56.92	57.34	57.76	58.19	58.62	59.05	59.49	59.93	60.37
CTS #8	N/A	112.89	113.74	114.59	115.45	116.32	117.19	118.07	118.96	119.85	120.75	121.66
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* Assuming cooling not available. With cooling LTR is 31.25 MVA.
** LTR will increase to approximately 195 MVA after T2 is replaced (2027)
*** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)
**** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Bluewater is not aware of any planned or proposed renewable generation connections that would require network investments or otherwise impact the regionally interconnected utilities.

Bluewater does not plan on making any investments in grid modernization equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities.

Bluewater has not completed and does not contemplate completing any projects or programs involving the study or demonstration of innovative processes, services, business models, or technologies over the forecast period.

5.2.2.3 IESO Comment Letter

There are no REG investments in the region, and Bluewater has not included any REG investments within the 5-Year DSP period, as such, a comment letter provided by the IESO is not required.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

This is Bluewater's first DSP, and as such, no prior DSP objectives are available for comparison.

5.2.3.2 Service Quality and Reliability

Bluewater uses the Service Quality Indicators ("SQI") outlined in Chapter 7 of the Distribution System Code to continuously evaluate the overall effectiveness of internal processes and systems and the distribution system to meet customer expectations.

The following Tables 8 and 9 outline the SQI for the historical years since last Rebasing in 2013. Chapter 2 Appendix 2-G has been filed in live Excel format with this Rate Application. Bluewater updated the formulas and overrode data where the pre-populated formulas were linking to the year prior. As such, the data is consistent with the scorecard. There have not been any material changes in SQI. Bluewater discusses reliability below in the Summary of Performance for the Historical Period.

Table 8: Appendix 2-G SQI: Service Reliability

Index	**Excluding Loss of Supply and Major Event Days**								
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
SAIDI	1.82	0.89	2.16	1.38	1.31	1.60	1.88	1.95	1.86
SAIFI	1.48	0.68	1.64	1.38	0.96	1.67	1.87	2.02	1.59
SAIDI	**5 Year Historical Average**								1.718
SAIFI									1.623
Index	**Including Major Event Days, Excluding Loss of Supply**								
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
SAIDI	1.82	0.89	3.28	1.38	1.31	2.20	1.88	2.29	2.92
SAIFI	1.48	0.68	2.09	1.38	0.96	1.98	1.87	2.22	1.98
SAIDI	**5 Year Historical Average**								2.120
SAIFI									1.802
Index	**Including Loss of Supply, Excluding Major Event Days**								
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
SAIDI	2.61	2.19	2.34	1.75	1.31	2.72	3.35	2.11	1.92
SAIFI	2.26	1.32	2.23	2.68	0.96	3.32	2.93	2.15	1.79
SAIDI	**5 Year Historical Average**								2.283
SAIFI									2.230
Index	**Including Loss of Supply and Major Event Days**								
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
SAIDI	2.61	2.19	3.46	1.75	3.13	3.69	3.35	2.45	2.97
SAIFI	2.26	1.32	2.68	2.68	2.20	3.75	2.93	2.34	2.17
SAIDI	**5 Year Historical Average**								3.118
SAIFI									2.678

Average Number of Hours that Power to a Customer is Interrupted – Through the years 2017 through 2020 Bluewater experienced an upward trend in the average number of hours that power to a customer is interrupted, from 1.31 hours to 1.95 hours. In 2021 Bluewater successfully reversed that trend, reducing it to 1.86 hours. Despite the improvement Bluewater still missed its distributor target of 1.66 hours, which is based on the 5-year previous year's average. Bluewater's target for the next 5 years is to improve its performance and score below its distributor target (as identified by the OEB) of 1.66.

Average Number of Times that Power to a Customer is Interrupted – The average number of times that Bluewater's customers experienced power interruptions increased from 2017 from 0.96 to 2.02 in 2020. Bluewater reversed this increasing trend in 2021, when the average number of interruptions per customer declined to 1.59. However, the improved score still did not meet the target of 1.51 times. Bluewater's target for the next 5 years is to improve its performance and score below its distributor target (as identified by the OEB) of 1.51.

Table 9: Appendix 2-G SQI: Service Quality

Indicator	OEB Minimum Standard	2013	2014	2015	2016	2017	2018	2019	2020	2021
Low Voltage Connections	90.0%	99.2%	94.2%	98.0%	98.30%	99.27%	96.89%	99.77%	100.00%	93.92%
High Voltage Connections	90.0%	100.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	77.0%	73.1%	75.6%	69.10%	78.01%	82.31%	87.40%	82.67%	86.26%
Appointments Met	90.0%	100.0%	99.8%	100.0%	99.60%	99.82%	99.72%	100.00%	100.00%	99.41%
Written Response to Enquires	80.0%	99.9%	100.0%	100.0%	100.00%	99.99%	99.82%	99.59%	99.84%	99.91%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.00%	100.00%	100.00%	100.00%	100.00%	100%
Emergency Rural Response	80.0%	100.0%	100.0%	N/A	100.00%	100.00%	N/A	N/A	100.00%	100%
Telephone Call Abandon Rate	10.0%	3.6%	4.3%	4.1%	4.80%	3.62%	2.97%	2.85%	2.65%	3.64%
Appointment Scheduling	90.0%	100.0%	98.2%	99.5%	99.60%	99.97%	99.89%	99.20%	98.83%	95.45%
Rescheduling a Missed Appointment	100.0%	N/A	86.1%	53.8%	100.00%	100.00%	100.00%	100.00%	100.00%	100%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.00%	99.39%	100.00%	100.00%	100.00%	100%

New Residential/Small Business Services Connected on Time – There has been some fluctuation in results for this metric. In 2021, Bluewater declined to 93.92%, from the previous years score of 100%, although still performed above the industry target of 90%. Over the past 5 years Bluewater's results have ranged between these two levels (93.92% – 100%) and Bluewater's goal is to continue to maintain this performance over the next 5 years.

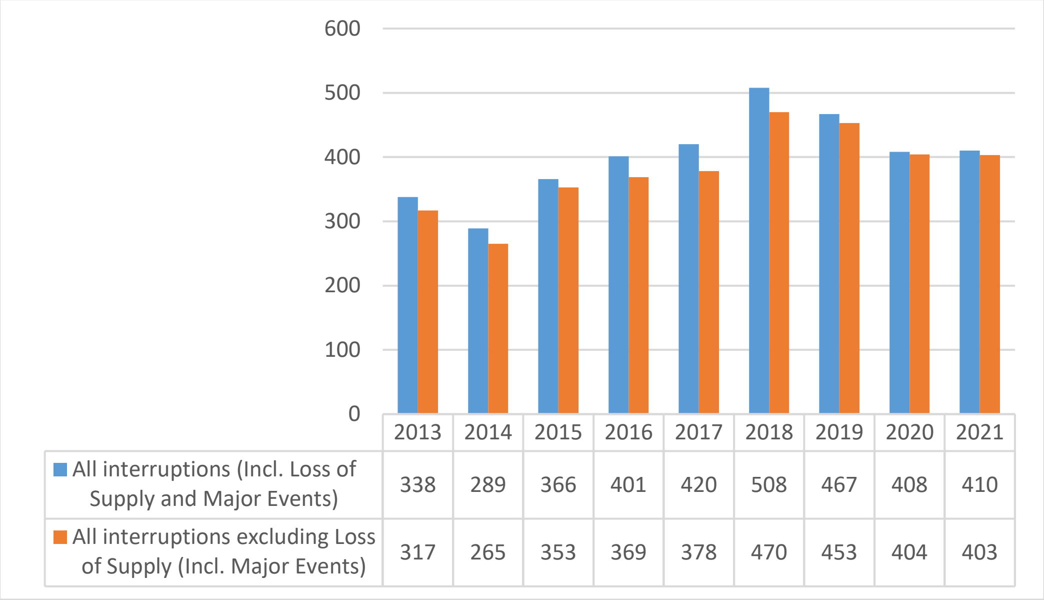
Scheduled Appointments Met on Time - Bluewater scored above 99% in each of the last five years. Bluewater intends to maintain this high rate of customer service over the course of the next five years.

Telephone Calls Answered on Time – In 2021 Bluewater reached one of its highest scores in this metric, with 86.26% of calls answered within 30 seconds, well above the industry target of 65%. Over the past five years Bluewater has averaged 83.9% of calls answered on time and will work to maintain this performance over the next five years.

Summary of Performance for the Historical Period

SAIDI and SAIFI are a measure used to identify overall reliability performance. Figure 5 presents all customer interruptions over the historical period from 2013 to 2021 (including loss of supply and major events), as well as all interruptions excluding loss of supply.

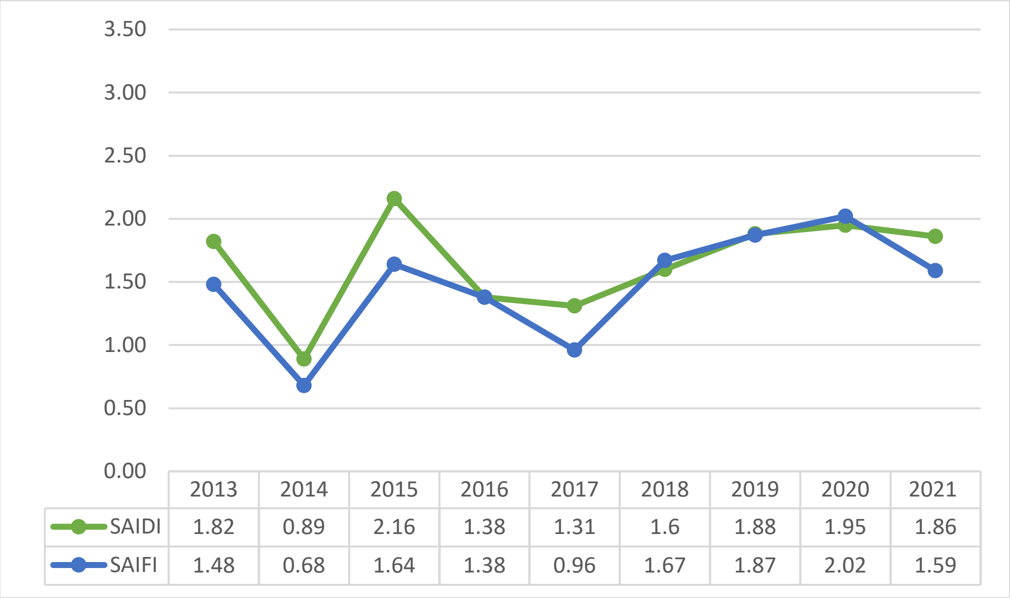
Figure 5: Historical Number of Customer Interruptions, including and excluding Loss of Supply



	2013	2014	2015	2016	2017	2018	2019	2020	2021
🟦 All interruptions (Incl. Loss of Supply and Major Events)	338	289	366	401	420	508	467	408	410
🟧 All interruptions excluding Loss of Supply (Incl. Major Events)	317	265	353	369	378	470	453	404	403

Figure 6 displays all interruptions, excluding major events and loss of supply, for SAIDI and SAIFI in the historical period.

Figure 6: Historical SAIDI and SAIFI; All Interruptions, excluding Major Events and Loss of Supply



	2013	2014	2015	2016	2017	2018	2019	2020	2021
SAIDI	1.82	0.89	2.16	1.38	1.31	1.6	1.88	1.95	1.86
SAIFI	1.48	0.68	1.64	1.38	0.96	1.67	1.87	2.02	1.59

Table 10 displays a summary of major events that occurred since the last Cost of Service filing in 2013.

Table 10: Historical Major Events

Interruptions caused by Major Events									
	2013	2014	2015	2016	2017	2018	2019	2020	2021
0-Unknown/Other									
1-Scheduled Outage									
2-Loss of Supply					12	4			
3-Tree Contacts			7					1	4
4-Lightning								1	
5-Defective Equipment									
6-Adverse Weather			2			14			18
7-Adverse Environment									
8-Human Element									
9-Foreign Interference						1			
Total Number of Interruptions caused by Major Events	**0**	**0**	**9**	**0**	**12**	**19**	**0**	**2**	**22**
Customer-Interruptions caused by Major Events									
	2013	2014	2015	2016	2017	2018	2019	2020	2021
0-Unknown/Other									
1-Scheduled Outage									
2-Loss of Supply					12,075	4,386			
3-Tree Contacts			11,397					356	8,043
4-Lightening								6,943	
5-Defective Equipment									
6-Adverse Weather			5,000			11,340			6,309
7-Adverse Environment									
8-Human Element									
9-Foreign Interference						13			
Total Number of Customer-Interruptions caused by Major Events	**0**	**0**	**16,397**	**0**	**12,075**	**15,739**	**0**	**7,299**	**14,352**
Customer-Hours of Interruptions caused by Major Events									
	2013	2014	2015	2016	2017	2018	2019	2020	2021
0-Unknown/Other									
1-Scheduled Outage									
2-Loss of Supply					26,901	13,407			
3-Tree Contacts			32,776					436	22,822
4-Lightening								12,166	
5-Defective Equipment									
6-Adverse Weather			7,833			22,044			16,156
7-Adverse Environment									
8-Human Element									
9-Foreign Interference						85			
Total Number of Customer-Hours of Interruptions caused by Major Events	**0**	**0**	**40,609**	**0**	**26,901**	**35,536**	**0**	**12,602**	**38,978**

As evidenced in Table 10, above, Bluewater experienced Major Event days in 2015, 2017, 2018, 2020, and 2021:

- **2015**: Adverse Weather and Tree Contacts were the main cause of a major event in July. The outage affected 16,397 customers for 6 hours and 55 minutes.
- **2017**: Loss of Supply from Hydro One caused a major event on March 4, when 4,270 customers were affected for 7 hours and 10 minutes
- **2018**: Adverse Weather was the main cause of a major event in May. There were high winds, fallen trees, and damaged power lines, causing outages to 13,580 customers for 4 hours.
- **2020**: Lightening was the main cause of a major event in September, hitting Bluewater's M26 breaker and affecting 7,299 customers for 2 hours and 21 minutes.
- **2021**: Adverse Weather and Tree Contacts were the primary cause of the major event in September, affecting 14,279 customers for 7 hours and 41 minutes.

Table 11: Five-year Average SAIDI and SAIFI and Target

Measure	OEB Target	2021 5-year average (2017-2021)
SAIDI	1.66	1.72
SAIFI	1.51	1.61

As evidenced in Table 10, above, Bluewater experienced Major Event days in 2015, 2017, 2018, 2020, and 2021:

- **2015**: Adverse Weather and Tree Contacts were the main cause of a major event in July. The outage affected 16,397 customers for 6 hours and 55 minutes.
- **2017**: Loss of Supply from Hydro One caused a major event on March 4, when 4,270 customers were affected for 7 hours and 10 minutes
- 2018: Adverse Weather was the main cause of a major event in May. There were high winds, fallen trees, and damaged power lines, causing outages to 13,580 customers for 4 hours.
- **2020**: Lightening was the main cause of a major event in September, hitting Bluewater's M26 breaker and affecting 7,299 customers for 2 hours and 21 minutes.

- 2021: Adverse Weather and Tree Contacts were the primary cause of the major event in September, affecting 14,279 customers for 7 hours and 41 minutes.
-

Table 11 shows Bluewater's 2021 5-year rolling average SAIDI and SAIFI as compared to the OEB target. The 5-year rolling average was slightly higher than the target in 2021 largely due to outages in 2020, explained below.

In 2018, there was an increase in the number and frequency of outages. Outages in Bluewater's rural regions were largely attributed to loss of supply due to the Wanstead TS being at the end of its life. For Bluewater's Sarnia customers, outages were mainly caused by defective equipment. The increase in defective equipment outages was largely due to underground cable faults in the Wellington Park and Sherwood Village subdivisions in Sarnia. As such, in 2018, Bluewater installed all new cables Sherwood Village to increase reliability. Bluewater also replaced a section of cable in Wellington Park, and Bluewater continues to prioritize this location for future investment.

Loss of Supply from Hydro One has historically contributed to outages, including Major Events. The conversion of Wanstead TS from 115 kV to 230 kV, as described below, was completed in 2018 and has drastically reduced the outages caused by Loss of Supply in subsequent years, with exceptional circumstances, outlined below, causing outages in 2019.

In April of 2019, Loss of Supply caused a significant outage, affecting 32,302 customers fed from the Modeland and Wanstead Transmission Stations. Power to 4,151 customers out of the Wanstead station was restored within 10 minutes, but the remaining customers fed from the Modeland station were without power for up to 2 hours.

The outage occurred due to two events happening at the same time. A Hydro One contractor working on 230 kV tower lines requested hold-offs on the protection for the two 230 kV circuits feeding Modeland TS which means, if there was a fault on the line, the breakers would open and not reclose as normal. During their work, contact was made by the contractor's equipment on one of the high tension lines resulting in an outage on that circuit. Thankfully, no personnel were injured.

The power remained on at this point because the companion feed to Modeland TS was still energized. Unfortunately, while the first feeder was off, the second feeder tripped off on differential protection. This resulted in a total loss of load at Wanstead and Modeland Transmission Stations feeding Bluewater customers and Wonderland TS feeding London Hydro customers – a total of 141 MW of power.

Power to Wanstead and Wonderland was restored by Hydro One picking up the feeder that tripped due to the differential protection, but they were unable to restore Modeland in this way because the fault was at or near the station. Bluewater operations staff worked to restore power to as many of its customers as possible by moving them to feeders out of St Andrews TS and over to Hydro One feeders coming in at Bluewater's borders until the damage from the contact on the first feeder could be investigated and corrected. Two hours and 12 minutes later, all power was restored to Modeland TS.

In 2020 outages continued to trend up slightly due to defective equipment and tree contacts. Bluewater has completed some projects and continues to replace end-of-life, direct-buried underground conductor (Project ID UT26) and is working with Bluewater's current tree trimming contractor to improve the process of clearing trees from around Bluewater's line. As a result, outages began to trend down again in 2021.

Outages by Cause

Bluewater measures the causes of interruptions to track the causes of large outages and identify trends year over year. As evident in Figures 7 and 8, Loss of Supply has consistently been a leading cause of outages, accounting for over 40 per cent of all customer outage hours in each of 2017, 2018, and 2019.

The loss of supply-related outages can be attributed to the fact that Bluewater is partially embedded in the Hydro One Networks Inc.'s distribution area. Hydro One's Wanstead Transmission Station supplies Bluewater's rural areas of Petrolia, Oil Springs, Watford, and Alvinston. Wanstead TS was beyond its useful life and causing reliability issues for Bluewater's rural customers.

In order to address these issues Bluewater contributed to the upgrade of the Hydro One TS. The upgrade from 115 kV to 230 kV required a capital contribution from Bluewater of $1,169,720 paid in annual payments made from 2015 to 2018. The multi-year project to modernize the station was completed in

2018. It has resulted in drastically reduced outages caused by loss of supply in subsequent years, with exceptional circumstances, outlined above, causing outages in 2019.

In 2021, the Number of Customer Hours of Interruption caused by loss of supply in Petrolia, Oil Springs, Watford, and Alvinston have decreased by 96% compared with 2018, as shown in Table 12.

Table 12: Cause Code 2 – Loss of Supply, Historical Outage Statistics for Rural Areas

Year	Number of Interruptions	2021 v 2018	Number of Customer Interruptions	2021 v 2018	Number of Customer Hours of Interruption	2021 v 2018
2018	37	-81%	36,166	-80%	52,786	-96%
2021	7		7,239		2,085	

Tables 13 through 22 depict the following for the historical period:

- number of interruptions that occurred as a result of the cause of interruption;
- number of customer-interruptions that occurred as a result of the cause of interruption; and
- number of customer-hours of interruptions that occurred as a result of the cause of interruption

These statistics are tracked to determine if trends are developing that might trigger a change in maintenance or capital spending.

Figures 7 through 9 depict these outages in graph form for a visual comparison.

Table 13: Cause Code 0 - Unknown/Other - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer-Interruptions	Number of Customer-Hours of Interruption
2013	12	1,301	1,423
2014	8	93	312
2015	17	15,426	19,922
2016	8	1,100	938
2017	17	1,634	838
2018	15	3,663	1,309
2019	14	2,624	3,035
2020	14	4,325	4,604
2021	15	5,650	3,535

Table 14: Cause Code 1 – Scheduled Outage - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	106	3,277	4,304
2014	101	4,263	6,391
2015	178	9,237	18,677
2016	219	11,926	16,090
2017	220	8,856	11,658
2018	246	8,790	17,894
2019	216	7,652	14,948
2020	202	3,142	4,722
2021	154	6,574	9,563

Table 15: Cause Code 2 – Loss of Supply - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	21	27,843	28,511
2014	24	23,233	47,003
2015	13	21,343	6,638
2016	32	47,055	13,420
2017	42	44,958	66,746
2018	38	65,064	54,936
2019	14	38,989	54,253
2020	4	4,603	5,638
2021	7	7,239	2,085

Table 16: Cause Code 3 – Tree Contacts - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	21	4,385	4,283
2014	22	5,918	9,458
2015	30	16,351	38,339
2016	24	13,016	6,518
2017	34	8,225	7,165
2018	30	16,283	12,475
2019	30	11,897	12,496
2020	32	7,553	11,580
2021	35	23,766	37,036

Table 17: Cause Code 4 – Lightening - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	17	12,322	4,090
2014	15	1,268	3,082
2015	4	767	1,130
2016	16	5,123	15,367
2017	11	2,633	5,380
2018	5	154	124
2019	24	4,467	2,374
2020	4	13,882	22,299
2021	6	579	380

Table 18: Cause Code 5 – Defective Equipment - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	90	16,272	14,339
2014	59	1,879	3,857
2015	70	19,595	20,604
2016	44	11,819	3,587
2017	40	2,016	3,665
2018	81	19,519	10,771
2019	67	10,534	8,500
2020	64	22,042	15,207
2021	79	10,982	18,426

Table 19: Cause Code 6 – Adverse Weather - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	19	13,295	34,571
2014	16	4,645	3,755
2015	22	7,214	11,945
2016	13	3,048	5,375
2017	14	2,069	2,014
2018	31	17,699	34,038
2019	46	13,853	18,534
2020	20	4,247	4,940
2021	48	10,548	22,708

Table 20: Cause Code 7 – Adverse Environment - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	2	12	13
2018	1	3,168	127
2019	0	0	0
2020	0	0	0
2021	0	0	0

Table 21: Cause Code 8 – Human Element - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	1	158	5
2014	0	0	0
2015	1	35	41
2016	2	1,595	187
2017	2	435	33
2018	22	688	786
2019	1	10	1
2020	1	404	22
2021	4	166	55

Table 22: Cause Code 9 – Foreign Interference - Historical Outage Statistics

Year	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
2013	51	2,189	2,218
2014	44	6,390	5,135
2015	31	6,593	7,914
2016	43	2,385	2,102
2017	38	9,299	16,902
2018	39	3,009	3,396
2019	59	17,915	9,317
2020	67	26,444	21,425
2021	62	15,027	16,344

Figure 7: Number of Interruptions by Cause Code

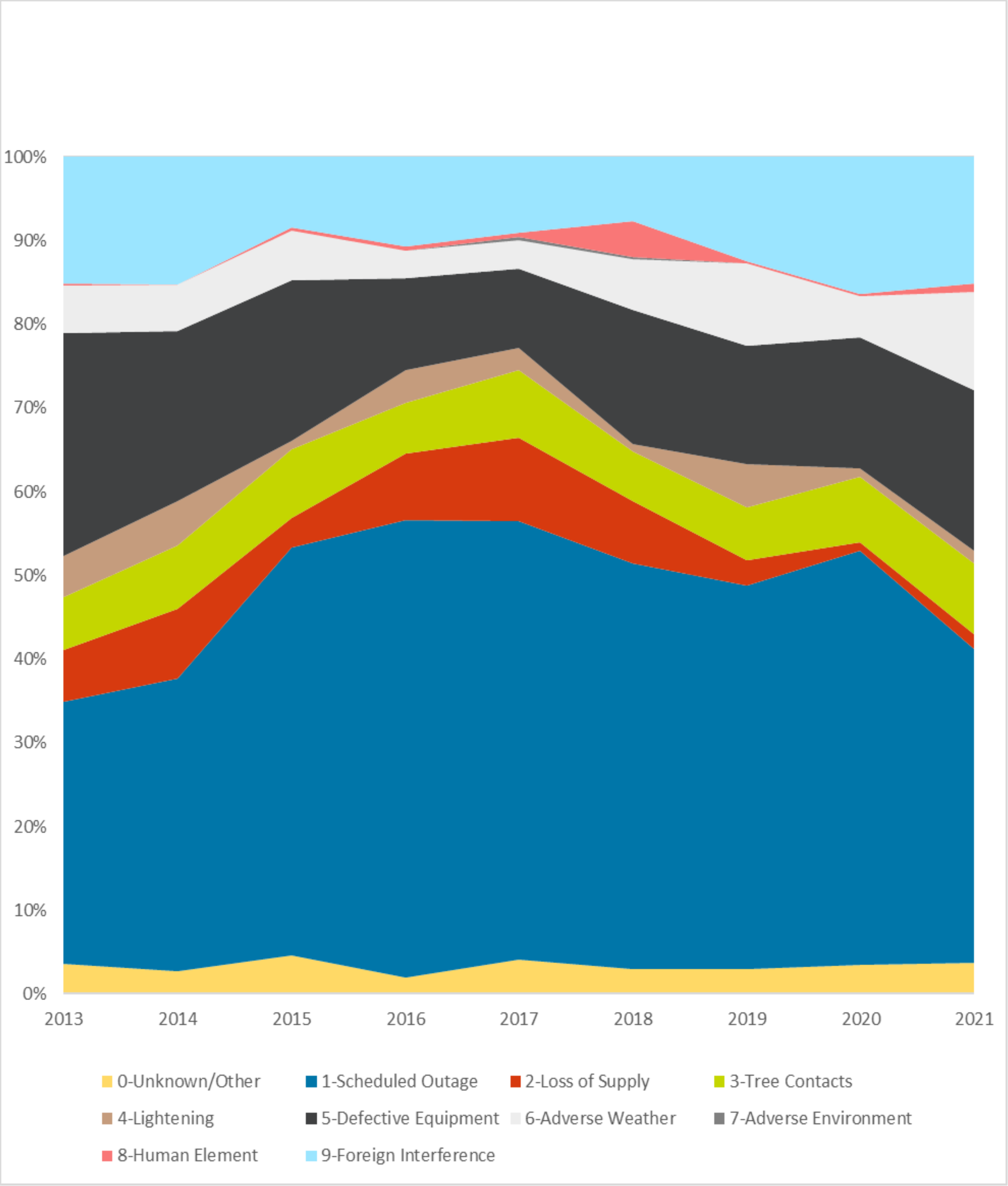


Figure 8: Number of Customer-Interruptions by Cause Code

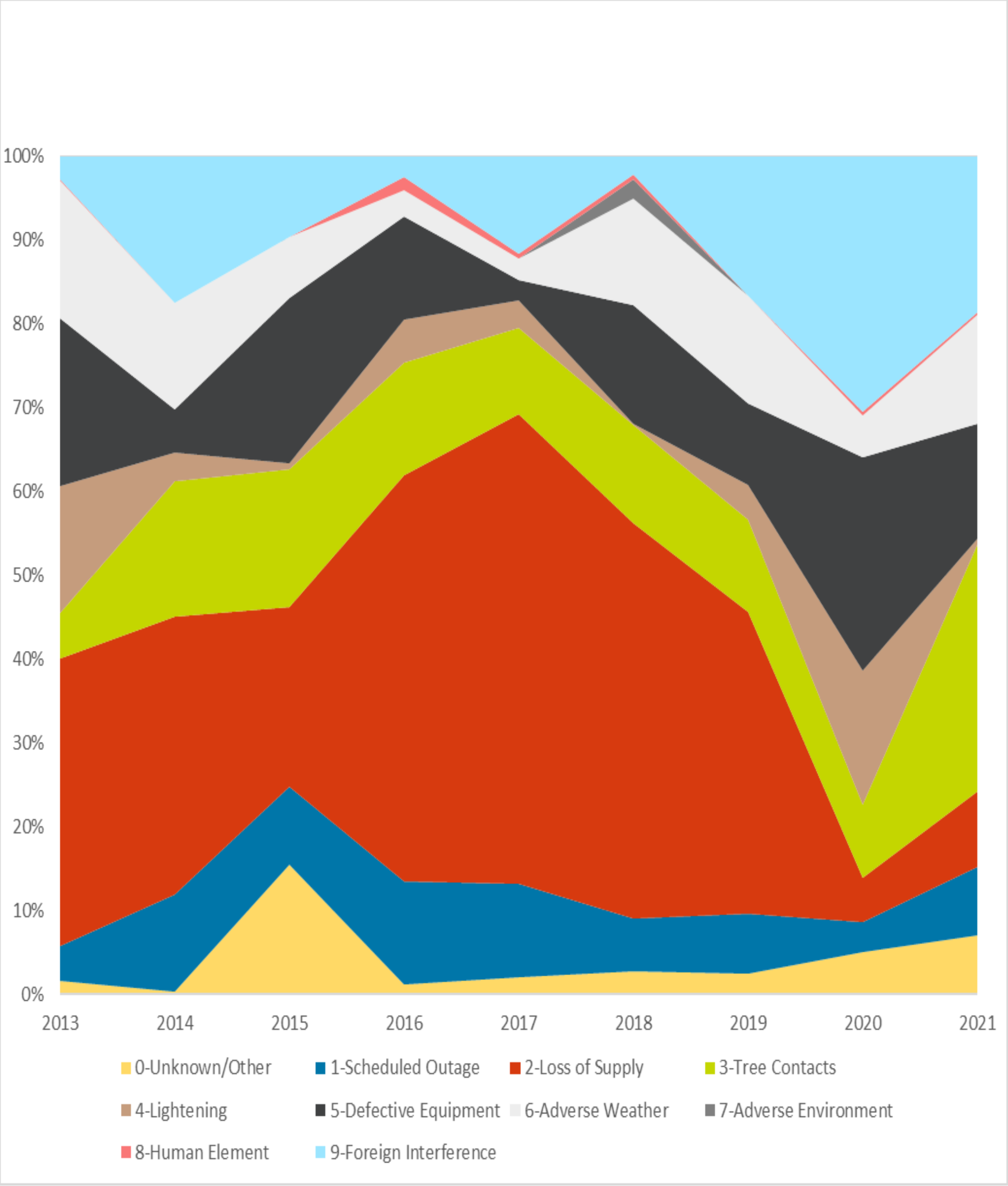
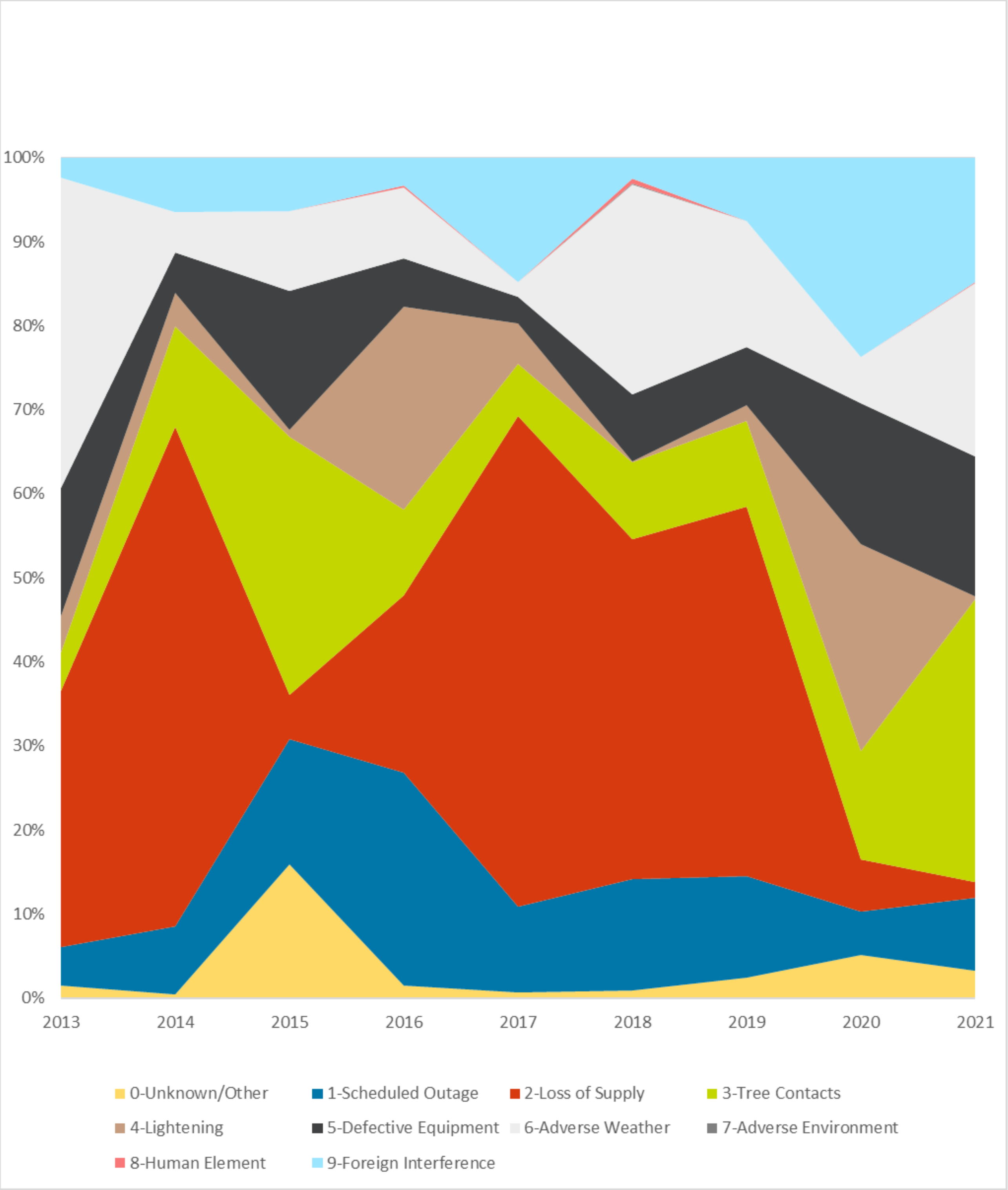


Figure 9: Number of Customer-Hours of Interruption by Cause Code



Loss of Supply outages have decreased given the upgrades to the Wanstead Transmission Station.

Outages related to Tree Contacts have increased as a result of decreased tree trimming and vegetation management in 2020 and 2021, primarily due to COVID impacts and contractor restrictions. Bluewater's third-party contracted tree service provider experienced severe staffing shortages due to COVID-19 and union issues. Beginning in 2020, the contractor began to fall behind and by the spring of 2021, they were nearly one year behind in the four-year cycle. Efforts were undertaken to catch-up, but they finished the contract term without having completed the final year of the contract. Bluewater issued a new RFP for Tree Trimming services in Q1 of 2022 and were successful in hiring a new service provider who commenced services mid-year. Accordingly, Bluewater expects there to be a catch-up period as there is overlap between Year 1 of the new contract and completion of Year 4 of the prior contract during the period from July 2022 to June 2023. As such, Bluewater expects decreases to the outages related to Tree Contacts in subsequent years.

Bluewater anticipates that increased replacement of deteriorating equipment nearing the end of its useful life will result in a decreased number of outages caused by Defective Equipment.

Weather-related impacts, including Lightening, Adverse Weather, and Tree Contacts amounts to almost half of the customer-number of outages. Within Bluewater's DSP, investments into capital projects such as Wood Pole Replacement Program (UT15), and Operating and Maintenance projects such as replacing defective lightning arrestors and increased tree trimming will help withstand future weather impacts. Also the planned installation of additional animal guards in areas prone to animal contacts will help reduce the number of outages caused by foreign interference.

5.2.3.3 Distributor-Specific Reliability Targets

Bluewater does not propose using performance expectations based on something other than historical performance.

Bluewater also does not propose using SAIDI and SAIFI performance benchmarks that are different than the historical average.

5.3 ASSET MANAGEMENT PROCESS

5.3.1 Planning Process

This section provides a high-level overview of Bluewater's asset management process. Bluewater follows an Asset Management Strategy ("AMS") that was prepared in 2011 with the assistance of a third party (AESI). It has been included as Appendix B.

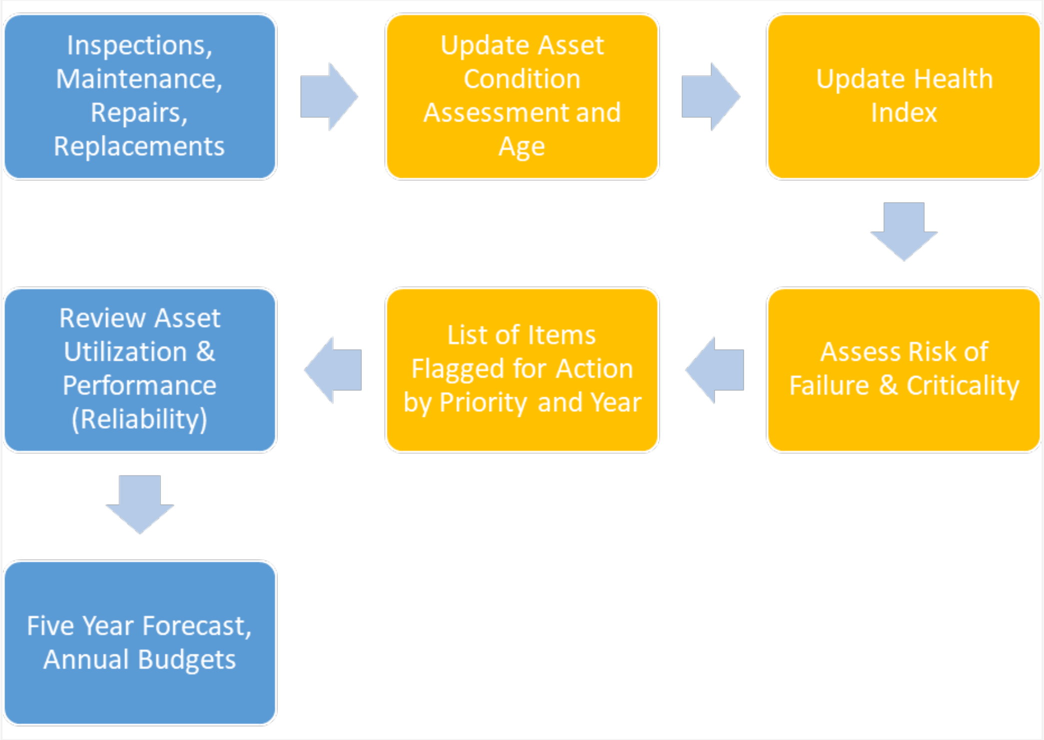
This is Bluewater's first DSP, and as such, there is no comparison with any prior DSP.

Bluewater's assets are managed by using technical support combined with the expert knowledge of Operations staff. Its Asset Management Plan is supported by using a combination of data systems:

- Geographic Information System ("GIS") is used to track individual pieces of equipment in the field, as well as customer and loading data geographically. All physical changes to the distribution system are captured in GIS on an ongoing basis. Documentation of inspection records is facilitated through the use of a mobile field mapping and data collection software application.
- Supervisory Control and Data Acquisition ("SCADA") plays an important role in the Bluewater Asset Management Plan by providing both real-time and historic distribution system data. SCADA is used to study feeder loading and to project future feeder loading, as well as to study system peaks. The data collected through SCADA is routinely used during the planning and implementation of capital and maintenance programs.
- The Bluewater Outage Management System ("OMS") is made accurate through diligent tracking. It is used to trend power outage by cause, by time of year, and by geographic location. This information is vital to the Asset Management Plan when prioritizing and supporting recommended capital and maintenance programs.
- The Bluewater Fleet Management System has been built in-house. The system houses all vehicle maintenance records, testing, and results. It facilitates fleet maintenance and provides supporting evidence for new vehicle purchase proposals.

The overall process for the management of Bluewater's key distribution assets is depicted in Figure 10. General Plant processes follow distribution assets in the section below.

Figure 10: Bluewater Asset Management Process Flowchart



**tasks in blue by Bluewater, tasks in yellow by third party*

5.3.1.1 Process

Each step of the Asset Management Process from Figure 10: Bluewater Asset Management Process is detailed, below:

Step 1: Inspections, Maintenance, Repairs, Replacements (Bluewater)

Bluewater collects and maintains data on key components of the distribution system in accordance to DSC requirements. Inspection of all devices are completed in compliance with the 3-year period for Bluewater's urban area and with the 6-year period for Bluewater's rural area. The key components are listed below:

- MS[1] Transformers
- MS Circuit Breakers (Air Magnetic, Bulk Oil, Vacuum)

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[1] MS = municipal station; a substation used to transform voltage from one primary voltage to another (such as 27.6 kV to 4.16 kV)

- MS Pad Mounted Switchgear
- Pole Top Transformers (Single Phase, Poly Phase, Rabbit Type[2])
- Gang Operated Overhead Switches (Manual, Motorized)
- Wood Poles
- Underground Cables (XLPE[3] Direct Buried, XLPE In Duct, PILC[4])
- Pad Mounted Transformers (Single Phase, Three Phase)
- Pad Mounted Switchgear

Bluewater maintains data such as age, inspection results and test results within the GIS system and provides it to a third party, Kinectrics, in order to prepare their annual Asset Condition Assessment Report ("ACA"). Further details about Bluewater's inspection and maintenance program can be found in subsection 5.3.3.2 System Operations and Maintenance Activities.

Step 2: Update Asset Condition Assessment and Age (Kinectrics)

Since 2014, Bluewater has retained Kinectrics to perform an Asset Condition Assessment on Bluewater's key distribution assets. Condition data can include nameplate information, test results, asset inspection records, corrective maintenance records, and operational experience. The 2021 Asset Condition Assessment can be found in Appendix A – Asset Condition Assessment (ACA) Report.

The reliability analysis is based on the most recent five years and identifies underperforming areas that may require additional analysis.

Step 3: Update Health Index (Kinectrics)

Kinectrics updates the Health Index annually using input data from Bluewater. The summary is found in Appendix A and Table 27. The Health Index quantifies equipment condition based on numerous condition parameters that are related to the degradation factors that cumulatively lead to an asset's end of life. It is an indicator the asset's overall health and is typically given in terms of a percentage, with 100% representing an asset in brand new condition.

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[2] A "Rabbit" type transformer is the common term for a single phase pole mounted transformer that is used to transform voltage from one primary level to another (such as 16 kV to 2.4 kV). It has two primary bushings on the top of the transformer that resemble the ears of a rabbit.

[3] XLPE = cross-linked polyethylene; a type of polymer used to insulate underground cables.

[4] PILC = paper insulated, lead covered; vintage cable insulation method using paper soaked in oil and covered with a sheath of lead. No longer in common use due to environmental issues with the oil and lead.

The Average Health Index results from the ACA are used to prepare the Flagged-for-Action list.

Step 4: Assess Risk of Failure and Criticality (Kinectrics)

The ACA provides a summary of the overall condition of each asset type, the health index distribution, as well as a prioritization list (based on condition, risk and criticality) along with identified data gaps.

Step 5: List of Items Flagged-for-Action by Priority and Year (Kinectrics)

For each of Bluewater's key distribution asset categories, Kinectrics develops a Condition-Based Flagged-For-Action plan (see Tables 23 and 24). The assessment methodology assumes all units flagged for intervention are replaced. In reality, only some of the units flagged for action in the first year will be dealt with, while the remaining units will be addressed in subsequent years.

The Flagged-for-Action plan is based on asset condition or age. It uses a probabilistic, non-deterministic approach and, as such, can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. The Flagged-for-Action plan signals Bluewater to assess the condition of the asset. Bluewater only replaces assets based on their condition. An asset being Flagged-for-Action does not mean it is necessarily being replaced.

Step 6: Review Asset Utilization and Performance (Bluewater)

Bluewater reviews the draft ACA report and provides feedback to Kinectrics through an iterative process, before the report is finalized.

Step 7: Five Year Forecast, Annual Budgets (Bluewater)

Bluewater Engineering and Operations staff use the results of the annual ACA, together with other considerations identified below, to identify, select, prioritize, and/or pace investments, thereby creating the budgets and five-year projections.

When considering the cut-off point, or envelope, for the budget, Bluewater considers the system needs, asset conditions, customer preferences and needs, including connection requests or complaints, and rate impacts in the budgeting process.

As outlined in further detail in at Appendix B, the development of the capital budget and five-year forecast occurs simultaneously and begins in the third quarter of each year with identification of projects proposed for inclusion within each. The scope and proposed expenditures of each project is developed and prioritized by the relevant departments.

Engineering projects are budgeted into high and medium priority. This is based on reliability, with high priority projects being necessary to ensure continued or improved reliability of the system. Medium priority projects improve the system and may affect reliability, but are better able to be paced than high priority projects. All other projects are categorized by type (such as municipal centered, metering, IT, other) and project priorities are not related to reliability.

A draft budget and forecast is then presented to senior management and subsequently to the Board of Directors for review of both and approval of the annual budget in the fourth quarter.

On a monthly basis, Bluewater reviews project statuses and year to-date results, including a comparison to budget and forecasted spending. Any known changes to forecasted spending, including any newly identified risks requiring immediate corrective action, are reviewed. Where necessary, projects scope and/or timing may be changed based on priority to allow for redirection of budgeted funds, ensuring Bluewater can operate within its established budget.

Measures to Identify and Select Investments

Flagged-For Action Plan

The Flagged-for-Action Plan (see Table 23 and 24) in the ACA is a guide for the Distribution System Plan. The plan is used to track assets that may need to be replaced in the forecast period. Bluewater monitors the condition of its system assets and invests in its assets to ensure they remain in a condition which allows for reliable electricity distribution. It is not expected that it be followed directly or as the final deciding factor in making sustainment capital decisions. As noted above, the Flagged-for-Action plan signals Bluewater to assess the condition of the asset. Bluewater only replaces assets based on their condition. An asset being Flagged-for-Action does not mean it is necessarily being replaced.

Bluewater also develops its DSP based on numerous other factors and considerations that influence asset management decisions, such as obsolescence, system expansion, regulatory requirements, and municipal demands.

Change in Population and Sample Size

Change in Population and Sample Size (see

Table 25: Summary Change in Population and Sample Size) data from the ACA is used in addressing assets that may need to be replace and identifying gaps in data that would affect sample size and population data.

Change in Health Index Distribution and Health Index Distribution Results Summary

Change in Health Index Distribution (see Table 27) and Health Index Distribution Results Summary (see Table 26) from the ACA are used to identify assets that may need to be replaced in the planning process.

Asset use and performance

Consideration is given to the utilization and performance of assets when considering options for maintaining assets. Generally, there are no capacity issues with the Bluewater territory so the utilization of individual components (such as transformers) is evaluated during inspections (noticeably overheating) or when conducting maintenance, repairs or replacements. System performance is analyzed by area and feeder to determine if trends are developing and if the level of investment in maintenance and replacement is keeping reliability where customers prefer it to be.

Project timelines

Many of the projects in Bluewater’s five-year projection are long-term or multi-year recurring projects. The Wood Pole Replacement Program (UT15), Cross Arm/Cap & Pin Insulator Replacement Program (UT14), and Primary Underground Cable Replacements Program (UT26) are examples of these types of projects. These projects reflect Bluewater’s goal of maintaining the system while improving reliability. Other projects are short term (one or two years) and are often based on results of the Asset Condition Assessment along with other tests or factors. Progress Drive Substation Upgrade (UT75) and Centre St. Petrolia (UT77) are examples of these types of projects. The ACA has flagged these assets as needing attention. Upon review of the oil testing and loading of the Progress Drive substation, Bluewater determined the best course of action was to upgrade this substation as well as Centre Street substation. Other projects are driven by needs that arise, either from Bluewater's customers or some other factor. St Clair Parkway in Sarnia (UT72) and PCB Tx Replacement (UT71) are examples of these types of projects. Chapter 2 Appendix 2-AA lists Bluewater's projects. This is found below as Table 38 and also filed in live Excel format.

Customer feedback

The valuable feedback Bluewater gains through ongoing customer engagement shapes Bluewater's capital expenditure plans.

Bluewater is dedicated to continuously engaging its valued customers through both daily business activities and specialized initiatives.

Informed by Bluewater's customers' preference to continuously improve the safety and reliability of the network (see the Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application), Bluewater has allocated the majority of its capital investments within the System Renewal category. Customer satisfaction with the reliability of electricity service has decreased since 2017 (see Oracle Poll Report in the Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application). As such, Bluewater has prioritized implementing programs to provide continued and improved power reliability, including wood pole replacements, as well as both the 4 kV Load Conversion and 8 kV Load Conversion programs (System Renewal).

The majority of customers favour improving technology to enhance the system. In response, Bluewater is investing in Remote Load Break Switches (System Service).

This DSP has been shaped by the results of the customer engagement by continuing to focus on maintaining a safe and reliable distribution system, while keeping costs competitive and gradually introducing new service offerings and modernizing the grid.

Additional details can be found in the Customer Engagement section in Exhibit 1 of Bluewater's 2023 Rate Application as to the various customer engagement activities and how they impacted this DSP.

Risk Management Tools and Methods

Risk management of assets is fundamental in aiding the justification, prioritization, and optimization of Bluewater's spending. A systematic approach to assess the following is taken with respect to each asset:

- Condition and age
- Location
- Operational data
- Maintenance
- Predictive maintenance
- Preventative maintenance
- Condition-based maintenance

To assist with risk management, Bluewater uses the AMS included in Appendix B. In addition, Bluewater uses information from the Asset Condition Assessment ("ACA"), specifically the Flagged-for-Action Plans mentioned above. The ACA uses data such as age and condition to rate assets in Bluewater's distribution system and identify items that need to be monitored or replaced.

The primary risk management tool used by Bluewater for the reliability and safety of distribution assets is the Risk Rating system, whereby deficiencies and hazards are identified and categorized, see Table 28.

Deficiencies and hazards are identified during inspections and condition assessments conducted by Bluewater staff. In conducting inspections and condition assessments, Bluewater divides its service territory into urban and rural sub-areas based on the location, relative population density, and in accordance with the OEB's definitions of urban and rural. The regions form the basis for Bluewater's systematic visual patrols. Inspections are such that one-third of the urban service territory is inspected on an annual basis and the rural service territory is inspected on a six year cycle. Thereby having inspected the whole urban and rural distribution system on a three and six-year cycle respectively.

In addition to routine visual patrols, several maintenance practices further contribute to the assessment, such as thermographic imagine. Feeder inspections, and dry-ice cleaning serve as secondary visual inspections. The systematic approach of inspections, condition assessments, data analyses, and maintenance allow for identification of risks to these assets. This approach allows Bluewater to mitigate risk to the assets and prioritize and support maintenance and capital expenditures.

Identified risks are then categorized based on an assessment of potential risk to health, safety, or property of the general public, utility workers, or the environment as a consequence of failure of the asset. The Risk Rating also includes guidelines for allowable response times to remediate the deficiency or potential deficiency. The Risk Rating categories are summarized in Table 28.

Cyber Security

Cyber security risk mitigation is a key component of Bluewater business practice. In order to manage this risk, Bluewater employs a number of measures that together combine to create a strong cyber security defense. These are constantly reviewed in conjunction with business partners, industry standards, and research and advisory sources. In response, Bluewater regularly puts in place new tools and processes that help to mitigate the ever-changing risks. Bluewater will continue to invest in hardware and software to enable us to fully comply with the OEB's Cyber Security Framework requirements.

Climate Change

Bluewater is a member of the Utilities Standards Forum that collaboratively reviews distribution construction standards to ensure they are in line with Canadian Standards. Bluewater will adopt any updated standards when the national or provincial standards change as a result of the risk of climate change.

Project Prioritization

Prioritization of capital projects for inclusion in the annual or 5-year budget is:

(1) Demand projects/ regulatory drivers (System Access)
(2) Bluewater initiatives (System Renewal, System Service, General Plant)

Demand and regulatory-drive projects are those driven by external entities, specifically municipalities, customers, government, and/or regulatory bodies, and are generally non-discretionary. Bluewater initiatives are identified as required to maintain or enhance the safety and/or reliability of the distribution system. The majority of these initiatives are recurring and may comprise activities that are required year-after-year, for example pole replacements, or may comprise a single project that requires execution over multiple years, for example voltage conversion to eliminate a substation. Further details of these types of projects by investment category follows.

Section 8.1 of Appendix B outlines that the capital projects are prioritized to create the annual capital budget and five year forecast. Planning projects for inclusion in the capital budget and five-year forecast follows a bottom-up approach: Bluewater collects and analyzes data, and then projects are identified and prioritized in the upcoming year or subsequent years.

System Access

Projects associated with connecting new customers and relocating assets to accommodate municipal projects (referred to as Demand Projects) have the highest priority, as the OEB obliges each LDC to accommodate these requests within prescribed timelines.

Bluewater receives requests such as relocating a pole line to accommodate municipal road works and connecting supply to a new subdivision or commercial development. Bluewater strives to meet its obligations to customer and municipal demands. Bluewater is generally apprised of these demands through its participation in monthly utility planning meetings. These meetings, in which various utilities, the municipalities, and developers participate, are used as a forum to provide notification of various upcoming or forecasted projects and to coordinate utilities for those projects. As such, demand projects are generally always included within the annual capital budget and may also be included within the five-year forecast where indicated through utility planning meetings.

The capital expenditures required to fulfill demand projects are estimated and based on material quotes and/or experience and may be extrapolated from previous years' budget; alternatively and for estimating expenditures for the five-year forecast, Bluewater uses projections of the expenditures, accounting for such things as inflation.

Regulatory drivers (such as implementation of customer choice RPP plans, the metering upgrades for the greater than 50 kW customers, monthly billing, and changes to bill presentment) also have high priority.

In the absence of any specific requests, historical average spending is used to set the budget amounts for the coming year and five year forecast.

System Renewal

Initiatives include recurring activities (such as asset replacements due to age and condition, system/safety enhancements, and capital expansions) and non-recurring initiatives (such as manhole lid replacements due to road work). Within this grouping, priority is given to projects that address safety and reliability issues or risks, enhance the performance of the system, enable the provision of new services to customers, or provide better tools to staff for performing their duties.

Asset replacement initiatives include replacement of existing distribution equipment, as well as capital rebuild projects. Projects are identified using the ACA, which is updated annually by a third party using data collected by Bluewater staff during system maintenance and inspections. The assets flagged-for-action in the ACA are reviewed by Bluewater in context of the other proposed initiatives and system plans to further refine the project priorities and scheduling.

System/safety enhancement initiatives include neutral upgrades, voltage conversion, safety signage, substation upgrades, and load balancing projects. These initiatives are generally identified through inspection and maintenance programs, load growth forecasts, and reliability reports (SAIDI/SAIFI). They are required to ensure or enhance safety and reliability of service, accommodate forecasted increase in load, or optimize configuration of the distribution system. Examples of initiatives include the installation of animal protection, lightening arrestors, second substation transformer for redundancy in the event of a failure of the primary transformer, and balancing of feeder loadings to avoid overloading during peak periods.

System Service

Initiatives include upgrades and modifications to the system to accommodate increased demand by existing customers. Generally, these initiatives are identified through forecasts or system planning and are required to accommodate forecasted increase in load and/or to ensure availability of supply. These may include feeder extensions to accommodate load growth and ensure supply reliability for customers. For each the recurring initiatives identified within the annual budget and five-year forecast estimates of the amount of capital contribution required are compiled. The estimates are generally based on actual expenditures from previous years where the scope of work is similar; alternatively, where the scope of work varies, expenditures are proportionately estimated. For the forecast, estimates of initiatives are adjusted annually based on achievements for a recurring project in previous years with respect to objectives in the upcoming years.

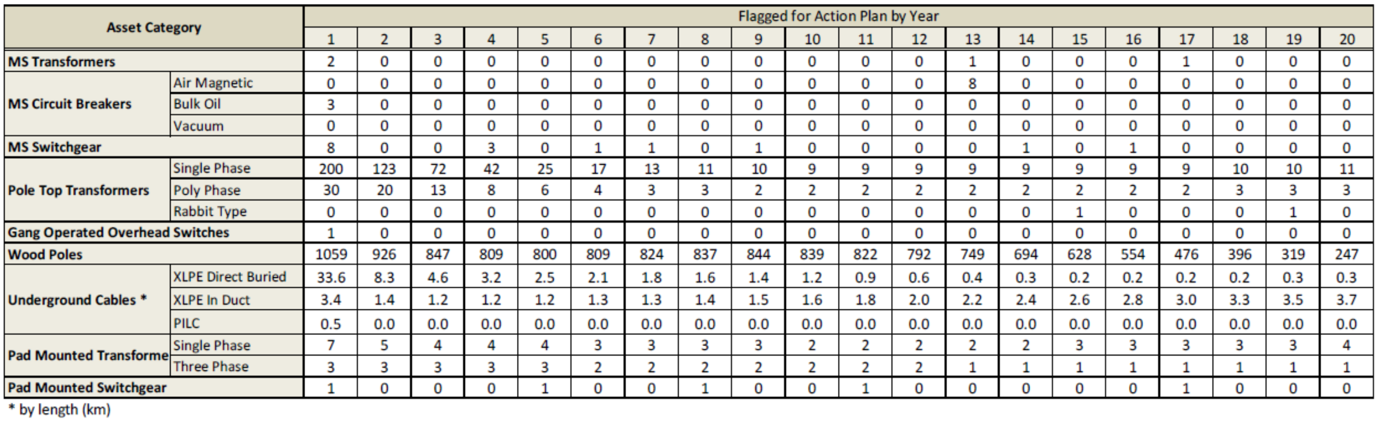
5.3.1.2 Data

Flagged-for-Action Plan

As noted in the section above, the Asset Condition Assessment Plan ("ACA") comprises a 20-year replacement strategy, as shown in Table 23.

Bluewater's replacement strategy is shown in Table 24, as documented in the ACA report. The results are based on asset condition and age. However, as noted above, Bluewater only replaces assets based on their condition; the Flagged-for-Action plan signals Bluewater to assess the condition of the asset. The tables only show possible expected failures or probable number of units that are expected to be candidates for replacement or other action. The two summaries are used as a guide for input for the DSP and not expected to be solely followed directly in making final asset management descisions.

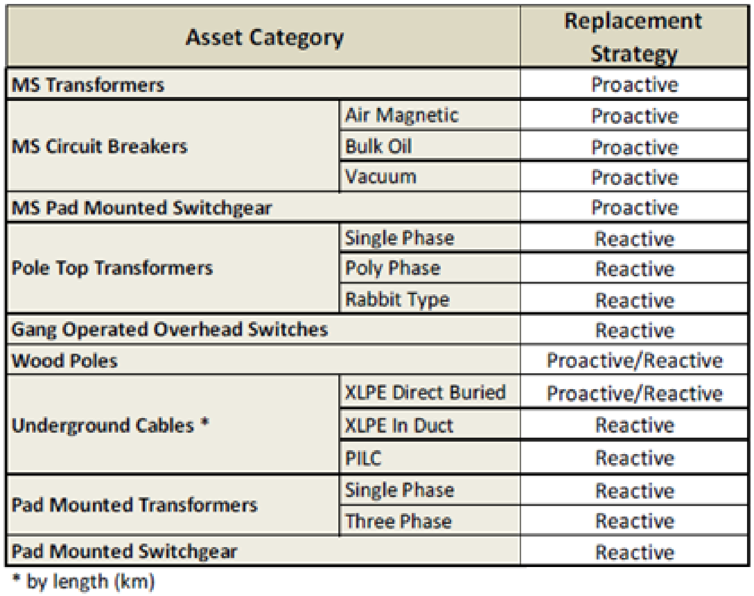
Table 23: Twenty-Year Condition-Based-Flagged-for-Action Plan (Year 1 is 2022)



Asset Category		Flagged for Action Plan by Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
MS Transformers		2	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0
MS Circuit Breakers	Air Magnetic	0	0	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0
	Bulk Oil	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Vacuum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MS Switchgear		8	0	0	3	0	1	1	0	1	0	0	0	0	1	0	1	0	0	0	0
Pole Top Transformers	Single Phase	200	123	72	42	25	17	13	11	10	9	9	9	9	9	9	9	9	10	10	11
	Poly Phase	30	20	13	8	6	4	3	3	2	2	2	2	2	2	2	2	2	3	3	3
	Rabbit Type	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0
Gang Operated Overhead Switches		1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wood Poles		1059	926	847	809	800	809	824	837	844	839	822	792	749	694	628	554	476	396	319	247
Underground Cables *	XLPE Direct Buried	33.6	8.3	4.6	3.2	2.5	2.1	1.8	1.6	1.4	1.2	0.9	0.6	0.4	0.3	0.2	0.2	0.2	0.2	0.3	0.3
	XLPE In Duct	3.4	1.4	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.6	1.8	2.0	2.2	2.4	2.6	2.8	3.0	3.3	3.5	3.7
	PILC	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pad Mounted Transforme	Single Phase	7	5	4	4	4	3	3	3	3	2	2	2	2	2	3	3	3	3	3	4
	Three Phase	3	3	3	3	3	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Pad Mounted Switchgear		1	0	0	0	1	0	0	1	0	0	1	0	0	0	0	0	1	0	0	0

* by length (km)

Table 24: Asset Replacement Strategy



Asset Category		Replacement Strategy
MS Transformers		Proactive
MS Circuit Breakers	Air Magnetic	Proactive
	Bulk Oil	Proactive
	Vacuum	Proactive
MS Pad Mounted Switchgear		Proactive
Pole Top Transformers	Single Phase	Reactive
	Poly Phase	Reactive
	Rabbit Type	Reactive
Gang Operated Overhead Switches		Reactive
Wood Poles		Proactive/Reactive
Underground Cables *	XLPE Direct Buried	Proactive/Reactive
	XLPE In Duct	Reactive
	PILC	Reactive
Pad Mounted Transformers	Single Phase	Reactive
	Three Phase	Reactive
Pad Mounted Switchgear		Reactive

* by length (km)

In addition to the above, Section 5.3.2 Overview of Assets Managed details asset information, including asset numbers, health, and age.

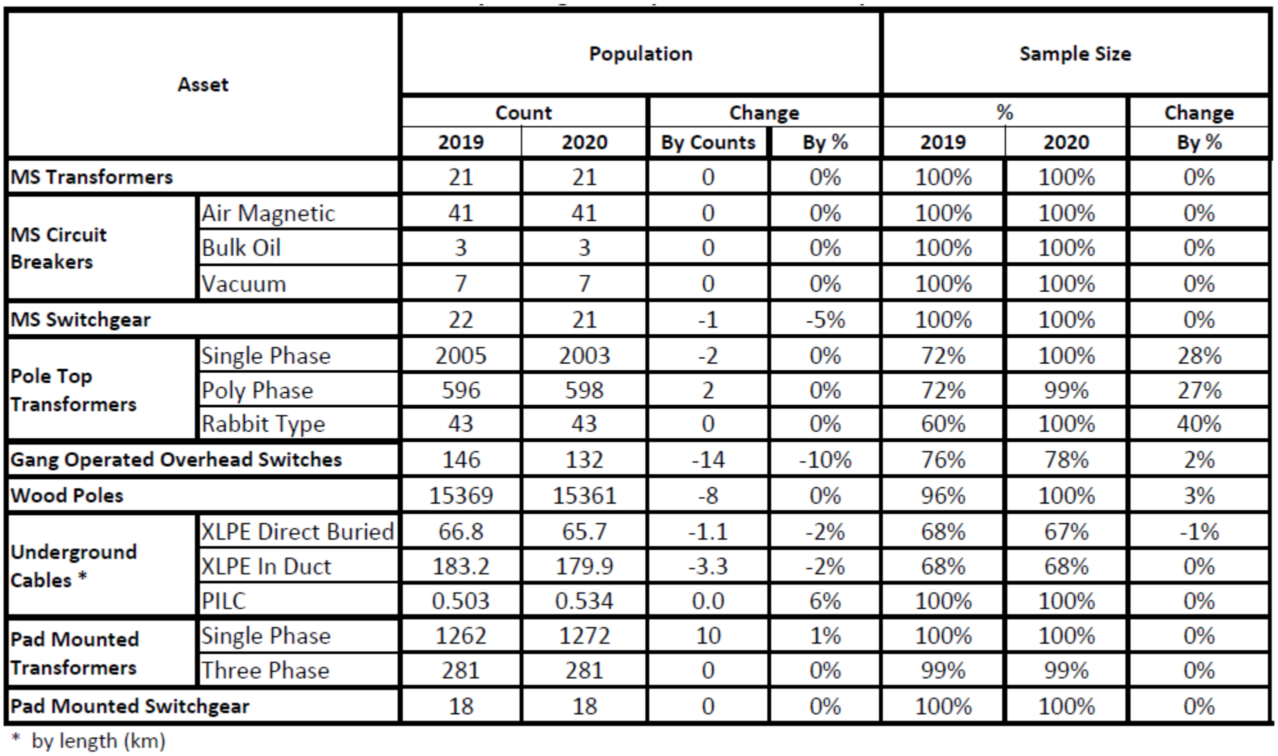
Change in Population and Sample Size

This measure of Asset and Systems Operations Performance tracks the change in population and sample size for each asset subcategory.

A summary of the change in population and sample size for each asset category between 2019 and 2020 is found in Table 25. This metric is calculated by a third party and expressed as a percentage in the ACA report (see Appendix A).

The target is for each asset class to have condition data available within its population, where the larger the sample size, the more confidence there is in extrapolating the Asset Condition Assessment results over an entire asset population.

Table 25: Summary Change in Population and Sample Size



Asset		Population				Sample Size		
		Count		Change		%		Change
		2019	2020	By Counts	By %	2019	2020	By %
MS Transformers		21	21	0	0%	100%	100%	0%
MS Circuit Breakers	Air Magnetic	41	41	0	0%	100%	100%	0%
	Bulk Oil	3	3	0	0%	100%	100%	0%
	Vacuum	7	7	0	0%	100%	100%	0%
MS Switchgear		22	21	-1	-5%	100%	100%	0%
Pole Top Transformers	Single Phase	2005	2003	-2	0%	72%	100%	28%
	Poly Phase	596	598	2	0%	72%	99%	27%
	Rabbit Type	43	43	0	0%	60%	100%	40%
Gang Operated Overhead Switches		146	132	-14	-10%	76%	78%	2%
Wood Poles		15369	15361	-8	0%	96%	100%	3%
Underground Cables *	XLPE Direct Buried	66.8	65.7	-1.1	-2%	68%	67%	-1%
	XLPE In Duct	183.2	179.9	-3.3	-2%	68%	68%	0%
	PILC	0.503	0.534	0.0	6%	100%	100%	0%
Pad Mounted Transformers	Single Phase	1262	1272	10	1%	100%	100%	0%
	Three Phase	281	281	0	0%	99%	99%	0%
Pad Mounted Switchgear		18	18	0	0%	100%	100%	0%

* by length (km)

Average Health Index Results

This measure of Asset and Systems Operations Performance tracks the average health index for each asset category.

Table 26: Health Index Results Summary is a summary of the Health Index Results showing the Health Index Distribution categories ranging from Very Poor to Very Good. The results provide the population,

sample size, the average health index, average age, average DAI and age availability for each asset category. These metrics are calculated by a third party and listed in the ACA report (see Appendix A).

The target is for each asset class to have a health index that is stable with minimal items listed in the very poor and poor categories. Under-performing assets are improved each year as a result of planned work. In some cases, the collection of additional data can result in a decrease in the health index which may not automatically trigger additional remedial work.

Table 26: Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
MS Transformers		21	21	80%	1	1	3	4	12	35	80%	100%
MS Circuit Breakers	Air Magnetic	41	41	69%	0	0	23	18	0	60	82%	100%
	Bulk Oil	3	3	30%	0	3	0	0	0	74	38%	100%
	Vacuum	7	7	92%	0	0	0	0	7	19	29%	100%
MS Switchgear		21	21	55%	0	8	8	2	3	49	67%	100%
Pole Top Transformers	Single Phase	2003	1993	77%	374	56	57	103	1403	31	99%	70%
	Poly Phase	598	591	88%	51	13	20	19	488	24	96%	71%
	Rabbit Type	43	43	98%	0	0	0	1	42	16	86%	63%
Gang Operated Overhead Switches		132	103	99%	1	0	0	0	102	16	75%	30%
Wood Poles		15361	15320	66%	1154	21	751	12792	602	29	85%	46%
Underground Cables *	XLPE Direct Buried	65.7	44.3	32%	26.5	4.2	0.9	6.1	6.7	41	67%	67%
	XLPE In Duct	179.9	122.3	97%	1.8	2.6	0.0	0.7	117.2	17	68%	68%
	PILC	0.5	0.5	0%	0.5	0.0	0.0	0.0	0.0	81	100%	100%
Pad Mounted Transformers	Single Phase	1272	1272	95%	10	7	31	75	1149	28	99%	88%
	Three Phase	281	279	93%	1	4	24	23	227	28	97%	87%
Pad Mounted Switchgear		18	18	88%	0	1	2	2	13	15	61%	78%

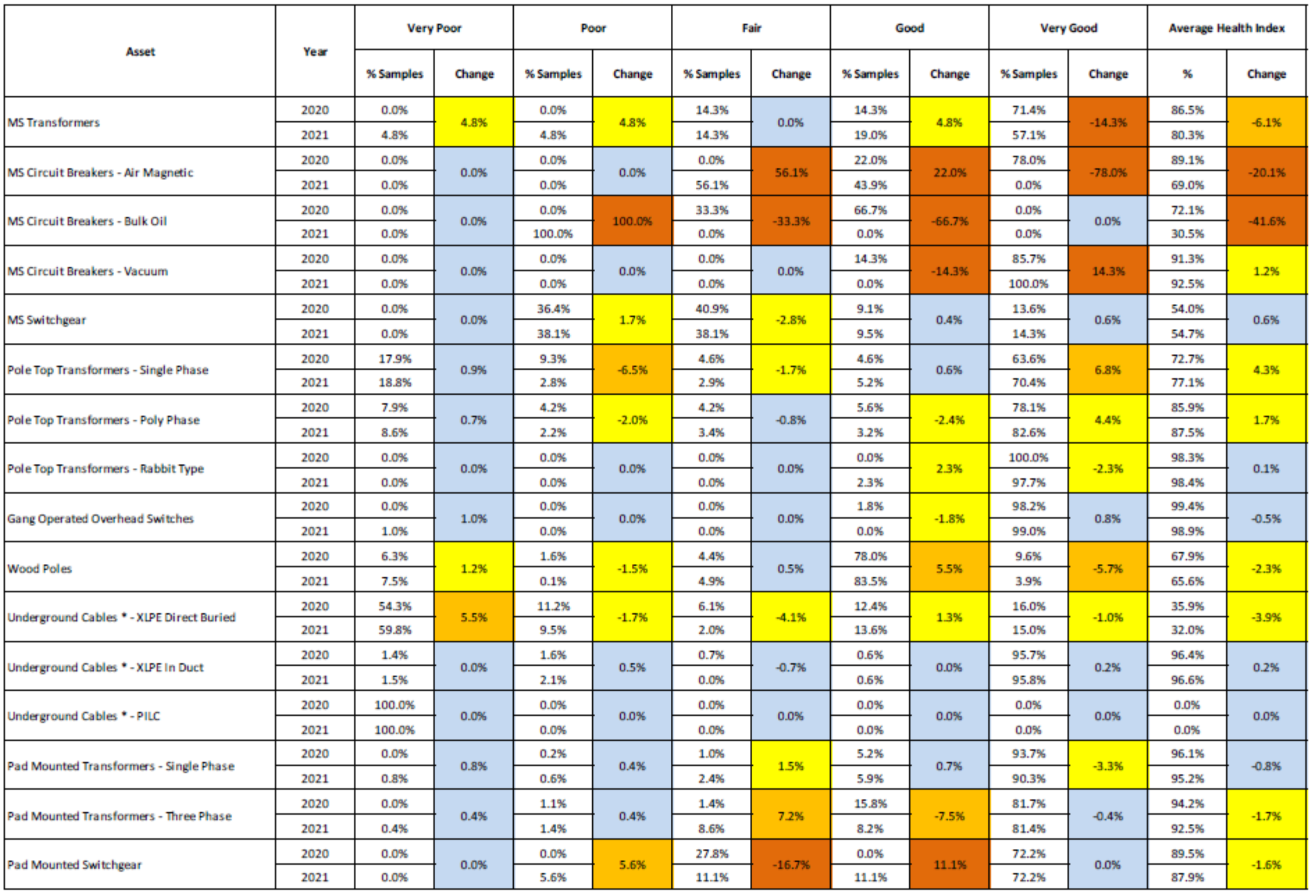
* by length (km)

Change in Health Index Distribution

A summary of the changes in Health Index distribution between 2020 and 2021 ACA studies is found in Table 27. This metric is calculated by Kinectrics and expressed as a percentage in the ACA.

The target is for each asset class to either have an improved increasing percentage of assets being classified as “good” and/or “very good” or a decreasing percentage of “very poor”, “poor” and /or “fair”. Where the asset would then be classified as having an overall improved health distribution. Conversely, asset classes with a decreasing percentage of “good” and/or “very good” or an increasing percentage of “very poor”, “poor”, and/or “fair” were classified as having an overall decline in health.

Table 27: Change in Health Index Distribution



Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	%	Change
MS Transformers	2020	0.0%	4.8%	0.0%	4.8%	14.3%	0.0%	14.3%	4.8%	71.4%	-14.3%	86.5%	-6.1%
	2021	4.8%		4.8%		14.3%		19.0%		57.1%		80.3%	
MS Circuit Breakers - Air Magnetic	2020	0.0%	0.0%	0.0%	0.0%	0.0%	56.1%	22.0%	22.0%	78.0%	-78.0%	89.1%	-20.1%
	2021	0.0%		0.0%		56.1%		43.9%		0.0%		69.0%	
MS Circuit Breakers - Bulk Oil	2020	0.0%	0.0%	0.0%	100.0%	33.3%	-33.3%	66.7%	-66.7%	0.0%	0.0%	72.1%	-41.6%
	2021	0.0%		100.0%		0.0%		0.0%		0.0%		30.5%	
MS Circuit Breakers - Vacuum	2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.3%	-14.3%	85.7%	14.3%	91.3%	1.2%
	2021	0.0%		0.0%		0.0%		0.0%		100.0%		92.5%	
MS Switchgear	2020	0.0%	0.0%	36.4%	1.7%	40.9%	-2.8%	9.1%	0.4%	13.6%	0.6%	54.0%	0.6%
	2021	0.0%		38.1%		38.1%		9.5%		14.3%		54.7%	
Pole Top Transformers - Single Phase	2020	17.9%	0.9%	9.3%	-6.5%	4.6%	-1.7%	4.6%	0.6%	63.6%	6.8%	72.7%	4.3%
	2021	18.8%		2.8%		2.9%		5.2%		70.4%		77.1%	
Pole Top Transformers - Poly Phase	2020	7.9%	0.7%	4.2%	-2.0%	4.2%	-0.8%	5.6%	-2.4%	78.1%	4.4%	85.9%	1.7%
	2021	8.6%		2.2%		3.4%		3.2%		82.6%		87.5%	
Pole Top Transformers - Rabbit Type	2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	100.0%	-2.3%	98.3%	0.1%
	2021	0.0%		0.0%		0.0%		2.3%		97.7%		98.4%	
Gang Operated Overhead Switches	2020	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	1.8%	-1.8%	98.2%	0.8%	99.4%	-0.5%
	2021	1.0%		0.0%		0.0%		0.0%		99.0%		98.9%	
Wood Poles	2020	6.3%	1.2%	1.6%	-1.5%	4.4%	0.5%	78.0%	5.5%	9.6%	-5.7%	67.9%	-2.3%
	2021	7.5%		0.1%		4.9%		83.5%		3.9%		65.6%	
Underground Cables * - XLPE Direct Buried	2020	54.3%	5.5%	11.2%	-1.7%	6.1%	-4.1%	12.4%	1.3%	16.0%	-1.0%	35.9%	-3.9%
	2021	59.8%		9.5%		2.0%		13.6%		15.0%		32.0%	
Underground Cables * - XLPE In Duct	2020	1.4%	0.0%	1.6%	0.5%	0.7%	-0.7%	0.6%	0.0%	95.7%	0.2%	96.4%	0.2%
	2021	1.5%		2.1%		0.0%		0.6%		95.8%		96.6%	
Underground Cables * - PILC	2020	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2021	100.0%		0.0%		0.0%		0.0%		0.0%		0.0%	
Pad Mounted Transformers - Single Phase	2020	0.0%	0.8%	0.2%	0.4%	1.0%	1.5%	5.2%	0.7%	93.7%	-3.3%	96.1%	-0.8%
	2021	0.8%		0.6%		2.4%		5.9%		90.3%		95.2%	
Pad Mounted Transformers - Three Phase	2020	0.0%	0.4%	1.1%	0.4%	1.4%	7.2%	15.8%	-7.5%	81.7%	-0.4%	94.2%	-1.7%
	2021	0.4%		1.4%		8.6%		8.2%		81.4%		92.5%	
Pad Mounted Switchgear	2020	0.0%	0.0%	0.0%	5.6%	27.8%	-16.7%	0.0%	11.1%	72.2%	0.0%	89.5%	-1.6%
	2021	0.0%		5.6%		11.1%		11.1%		72.2%		87.9%	

The following Risk Ratings table is sourced from the AMS (Appendix B, page 7). Overall risk-ratings are assigned by a System Inspection Powerline Technician or other qualified person ("Asset Inspector"). The risk-rating is a colour-coded system whereby each colour is representative of the varying degree of risk, is generally based on an assessment of potential risk to health, safety, or property of the general public, utility workers, or the environment as a consequence of failure of the asset; the risk rating also includes guidelines for allowable response times to remediate the deficiency or potential deficiencies.

Table 28: Risk Ratings

Risk Rating	Required Action
Red	Immediate and urgent attention required; poses a risk to the general public, utility, workers, property and/or the environment. Generally includes items that are broken, rotten, missing, leaking, etc.
Orange	Requires timely, corrective action to mitigate hazard to the public, employees, property and/or the environment. Generally includes items that are damaged.
Yellow	Maintenance will be required in 2 – 5 years
Blue	Maintenance will be required in 5 – 10 years
Green	Maintenance will be required in 11 – 20 years

5.3.1.3 General Plant Asset Management

Fleet

Bluewater follows its Fleet Management Plan (Appendix E).

A history of the condition, maintenance, inspections, required repairs, and annual costs are documented and recorded in Bluewater's Collective Data Fleet software program. Bluewater annually reviews costs and condition of all units as a part of its recommendations for vehicle upgrades and replacement.

Other factors such as age, mileage, engine hours, Power Take Off hours, appearance, and frequency of use are all contributors to the decision-making process to upgrade or replace an asset.

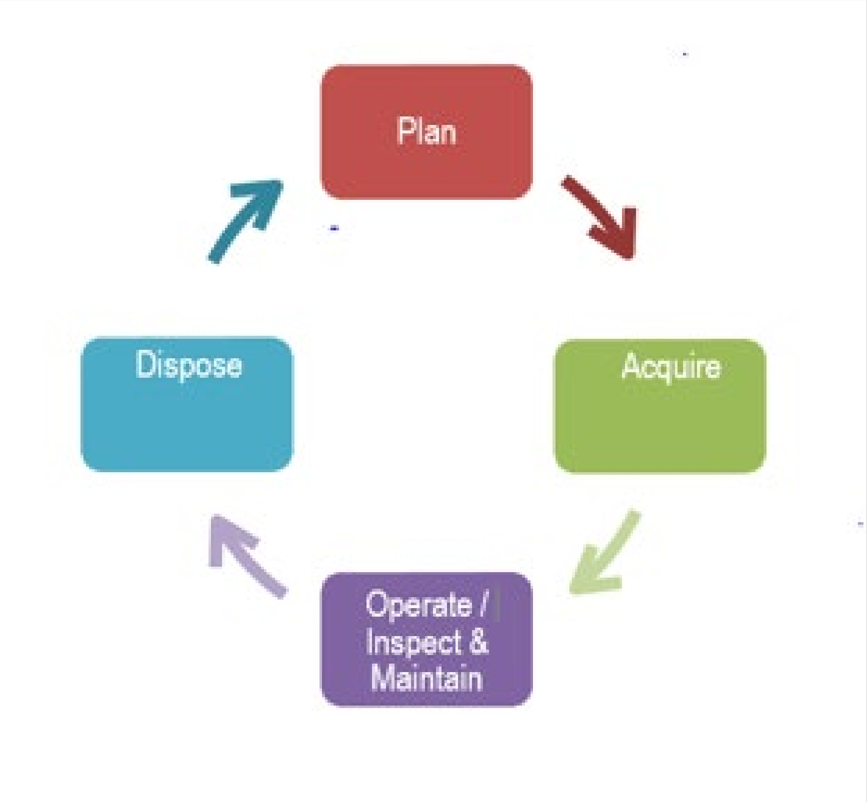
Vehicle replacements are identified through Bluewater's comprehensive fleet management system. Using Fleetio and GeoTab software programs, Bluewater tracks kilometres driven, litres of fuel per kilometre, corrective maintenance, planned maintenance, and required testing for each vehicle in its fleet.

Bluewater manages its fleet to ensure the following objectives can be achieved consistently and are sustainable over time:

- maximize the operational effectiveness of the workforce by maximizing operational functionality and availability of the vehicles;
- maximize asset longevity through effective purchasing specifications, operational inspections and maintenance;
- minimize total lifecycle costs by tracking operational and maintenance costs as well as downtime costs;
- maximize safety of the fleet by minimizing accidents and incidents.

Bluewater follows a Life Cycle approach to Fleet Management, as shown in Figure 11: Life Cycle Approach to Fleet Management.

Figure 11: Life Cycle Approach to Fleet Management



Plan - Bluewater prepares and reviews annually a five-year replacement schedule which is informed by regular asset condition assessments (as detailed in the Fleet Management Plan at Appendix E). Due to the lead time it takes to budget, order, receive and place into service, vehicles are typically planned for replacement when assessments indicate fair to poor condition. By the time the existing assets are removed from service, they will have normally deteriorated to poor or very poor condition.

Replacement of Heavy Duty Boom vehicles are ordered 12 to 18 months or longer in advance of replacement due to manufacturing wait times. Medium Duty work vehicles normally are ordered 12 months in advance and Light Duty vehicles such as trucks, trailers, and vans, are usually obtainable within the year they are being replaced. The COVID-19 Pandemic has affected ordering times and certainty.

Acquire – Detailed purchasing specifications are utilized for the largest and costliest assets. Specifications are reviewed and if needed updated before each submittal for tender. The number and type of vehicles in the fleet at any point in time is determined by the size and scope of Bluewater's work program.

Operate, Inspect & Maintain – Bluewater performs regular inspection and maintenance on all assets. Defects or deficiencies are recorded and flagged for action. The level of detail and frequency is determined by asset category, regulatory requirements and condition of the equipment. See section 5.3.3.2 System Operations and Maintenance Activities for a summary of Fleet Inspections and Maintenance practices.

Disposal – Bluewater disposes of its Fleet assets when they are normally in poor or very poor condition. They are no longer economical, safe or reliable enough to withstand the daily rigors of utility operations or construction on high voltage lines. Vehicles for disposal are normally sold at auction or donated to college programs.

Information Technology ("IT")

Bluewater Information Technology prioritizes projects based on 4 guiding principles: advancing Customer and Business Functions, ensuring continuity of technology platforms, responding to regulatory change requirements, and providing mitigating solutions to guard against cyber security threat.

Bluewater Information Technology uses 4 guiding principles that frame the components of the asset management process:

1. Advancing Customer and Business Functions.
    a. Bluewater seeks to use technology to enhance the customer experience.
    b. Bluewater implements technology that enables the business functions. This technology is constantly being upgraded, enhanced, or replaced in order
2. Ensuring Continuity of Technology Platforms.
    a. Both hardware and software need to be upgraded and or replaced on a regular basis given the typical change that occurs with technology. Generally, hardware is changed out on a lifecycle basis of 3 to 6 years. Software usually follows an upgrade path that includes regular patches and occasional full version upgrades. These take place to continue with the maturing of software that includes corrections, security patches, and enhancements.
3. Responding to Regulatory Change Requirements.
    a. Regular changes to industry direction occur which result in regulatory change requirements. As they relate to technology, Bluewater invests in ensuring compliance extends to technology platforms.
4. Providing Mitigating Solutions to Guard Against Cyber Security Threat.
    a. As more and more connectivity and integration of technology platforms occurs, the threat of cyber attack grows. Bluewater Technology works continually to ensure proper measures are in place to mitigate this threat

Within those principles, project prioritization is driven by a number of factors.

- Product lifecycle
    - IT hardware assets are purchased with the intent of a lifecycle that is generally 3 to 6 years. These are based on manufacturer recommendations and historical usage data. Software is regularly developed and given release cycles and patches for security and bug fixes. All applications are kept up to date for security requirements and are considered for release upgrades on a case by case basis.
- Staff availability
    - In planning a multi-year prioritization of technology projects, staffing levels are considered such that projects are done in a cadence that allows for consistent work levels.

  - This is a priority given Bluewater's philosophy to manage its IT systems through in-house expertise.

- Cyber security threat
  - Regular reviews of current cyber threats in conjunction with current technologies often creates prioritization of projects accordingly.
- Regulatory and business deadlines
  - The ebb and flow of regulatory change and business opportunity are considered in the prioritization of planning and implementing technology projects.

Bluewater has developed a highly capable internal team as part of its philosophy to drive value through in-house expertise. This includes the development of hardware and programming expertise, which has permitted in-house disaster recovery as well as multiple examples of custom developed software solutions. This approach to staff development was necessary as part of Bluewater's strategic decision to adopt a continuous improvement approach to its SAP enterprise software rather than the more traditional approach of periodic upgrades with each version change in the software. This approach is more cost effective without compromising the capabilities of the system.

Building

An annual budget is established to maintain and repair Bluewater's Service Centre. Improvement at the Centre is an on-going sustaining program that is required to keep Bluewater's main building in reasonable condition. The building is approximately 55 years old and requires maintenance and repairs with respect to items such as:

- Replacements of old and/or defective windows, doors, and fences
- Heating and cooling upgrades
- Roof repairs, as required
- Landscaping, as required

The Service Centre is Bluewater's main office and houses Administration, Customer Service, Engineering, Operations and Purchasing for Bluewater. All repairs are required for security, health and safety, building integrity to protect equipment located within the Service Centre, as well as aesthetics.

Besides routine items, projects are implemented on a reactive and proactive basis. Regular inspections are carried out and result in projects such as HVAC and roofing replacement or lighting upgrades. Bluewater also reacts to urgent needs such as leaks or worn components resulting in projects such as door replacements or parking lot repairs.

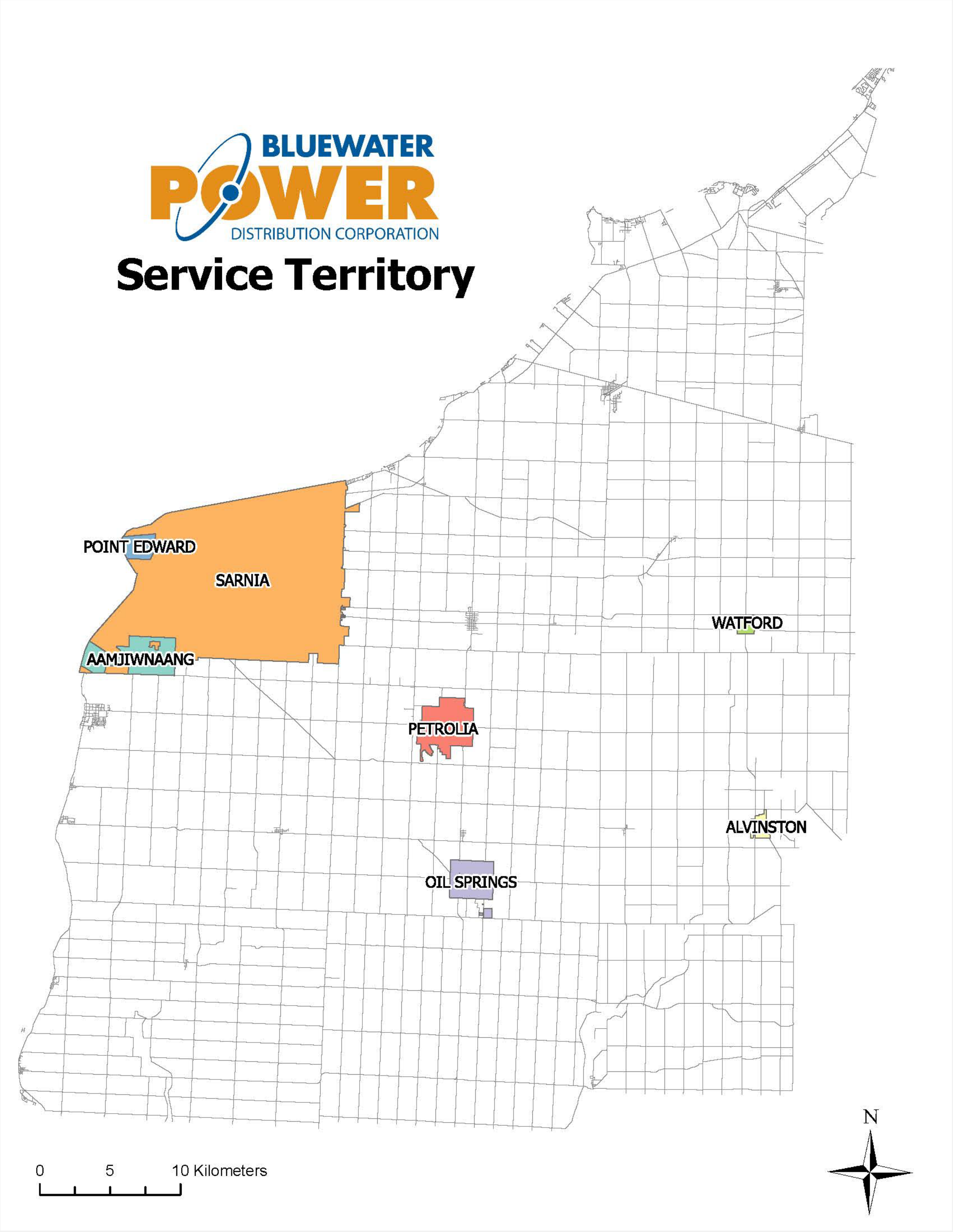
Included as part of the building are the lands associated and, in particular, the fenced-in rear yard which provides critical outside storage. The overall capital budget has doubled over the past decade, placing significant demands for outside storage. Bluewater has invested in improvements to outside storage, including adding racking systems for transformers and poles, but the ability to go "up" has been largely exhausted. Bluewater has attempted to negotiate land acquisitions and swaps, but efforts have not been successful to-date.

5.3.2 Overview of Assets Managed

5.3.2.1 Distribution Service Area

Bluewater was created as the result of the merger of six former municipal hydro-electric commissions and currently serves the City of Sarnia, which includes Aamjiwnaang First Nation, Town of Petrolia, the Villages of Point Edward and Oil Springs, the Township of Warwick, and the Township of Brooke-Alvinston. Bluewater provides electrical distribution services to approximately 37,000 residential and commercial customers in its service area throughout Southwestern Ontario as illustrated below in Figure 12: Bluewater Service Area. Hydro One serves customers in the areas surrounding Bluewater's service territory within Lambton County.

Figure 12: Bluewater Service Area



The only neighbouring LDC is Hydro One Networks Inc. that provides service to primarily rural customers outside the boundaries of Bluewater.

Weather

Weather patterns are typical for this area of Ontario, with the climate described as humid continental (Koppen climate classification Dfb). The proximity of Sarnia and Point Edward to Lake Huron moderates temperature swings but can be a source of lake effect snow, which can also impact the rest of the service area. Overall, the weather has not required Bluewater to make any changes to distribution construction standards.

Urban/Rural

The City of Sarnia and the Village of Point Edward are considered urban while the Municipality of Alvinston, the Village of Oil Springs, the Town of Petrolia, and Watford are considered rural. Approximately 72% of the system is overhead construction with most of the newer residential and commercial areas using underground construction.

Service Territory Characteristics

The economy within Sarnia and Point Edward is dominated by the chemical industry, which makes the overall system load vulnerable to national and global impacts such as the fluctuating price of crude oil and changes in environmental policies and trends. Most of the larger industries are transmission connected; however, Bluewater has seen an overall drop in peak load since 2012.

The remaining areas of Bluewater are rural with farming as the major economic driver, which has been relatively stable for the past decade.

As a result, Bluewater expects the existing bulk supply (transformer stations and feeders) to be sufficient for the foreseeable future, and there are no plans within this DSP for added capacity.

System Configuration

The Bluewater system consists of approximately 935 circuit km of overhead line and 270 underground circuit km of line.

There are two Hydro One owned transformers stations (St Andrews and Modeland) supplying Sarnia and Point Edward, one Hydro One owned transformer station (Wanstead) supplying Petrolia and Watford (via feeders shared with Hydro One), and two Hydro One owned distribution stations (Alvinston and Oil Springs connected to feeders from Wanstead TS) supplying Alvinston and Oil Springs (via feeders shared with Hydro One).

In Sarnia and Point Edward, there are thirteen (13) feeders at 27.6 kV that are exclusive to Bluewater. The remaining areas are each supplied by feeders shared with Hydro One. There are no known capacity issues with any of the supply points, thus there are no plans within this DSP to provide additional capacity.

5.3.2.2 Asset Information

Asset Capacity

As noted in Section 5.3.2 b), there are no known capacity issues with any of the supply points, thus there are no plans within this DSP to provide additional capacity. Bluewater monitors loading of feeders and stations and uses infrared scanning to detect individual components that are operating above capacity (or have other deficiencies such as poor connections), and smart meter data is now used to check the loading of transformers prior to replacement to ensure the appropriate size is used.

Bluewater is also expecting an increase in loading due to the adoption of Electric Vehicles (“EVs”) by its customers in the coming years. Our main focus will be in the 4 kV system which will require more capital spending than its 27.6 kV system to ready it for the additional load car chargers are expected to bring on. In 2023, Bluewater budgeted capital funds (UT74) to upgrade part of the 4 kV system to 27.6 kV in order to reduce some of the load on one of its most heavily loaded substations. In addition, Bluewater has been working to balance 4 kV feeders and reconfigure feeders to even out the load on each feeder with the goal of having one spare breaker position in each 4 kV substation to be used in an emergency or to pick up more load as required. Although it is outside the scope of this DSP period, Bluewater is also considering options with the 4 kV system, specifically whether to convert to 27.6 kV or upgrade the existing 4 kV system. A decision will be made and a plan will be laid out in time for the next rebasing application.

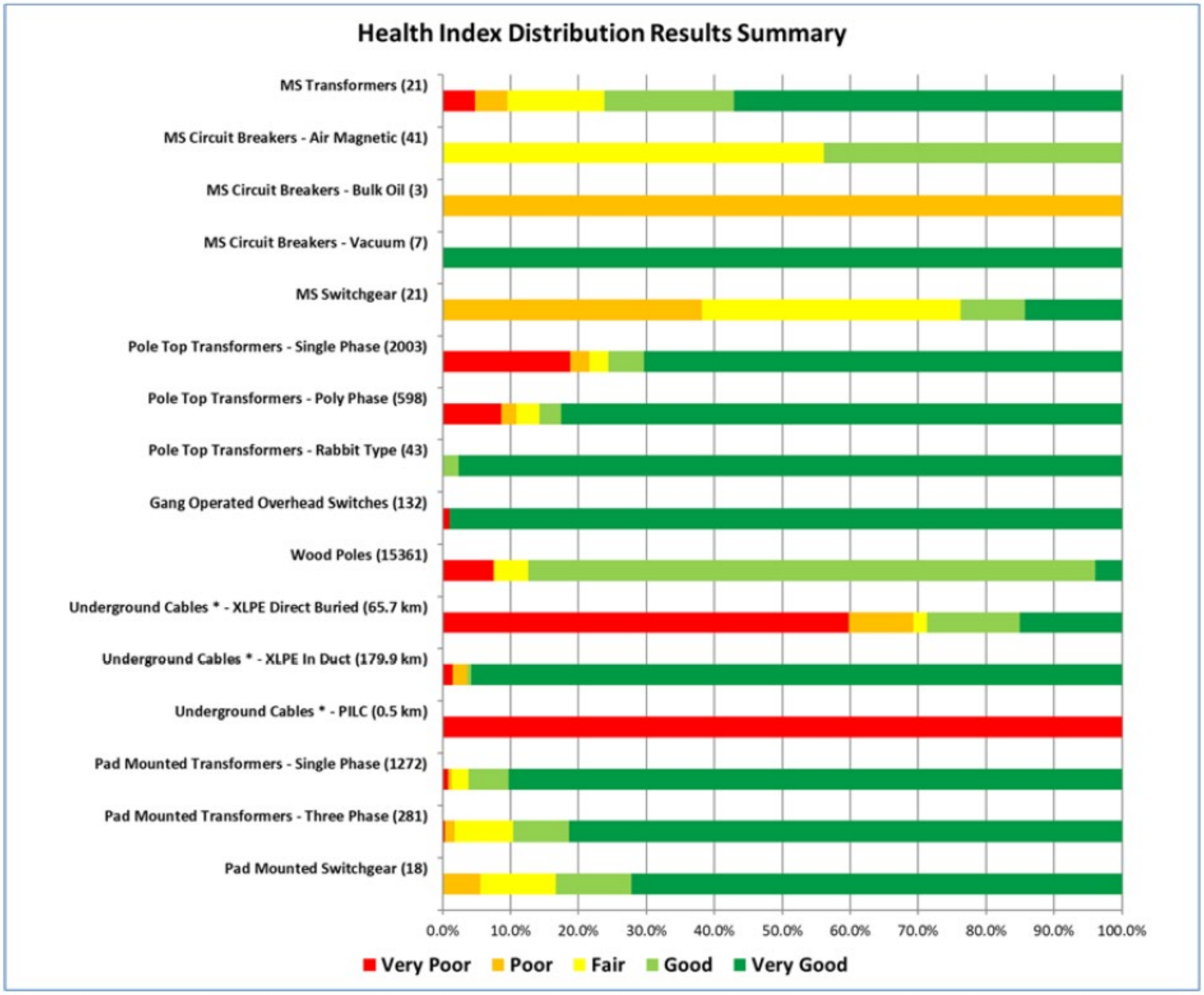
Summary of Assets

Key Distribution Assets

Bluewater retained Kinectrics to complete an Asset Condition Assessment ("ACA") of its distribution system. The report, dated October 25, 2021, is attached as Appendix A: Asset Condition Assessment. The ACA was conducted for nine of Bluewater's key distribution asset categories.

A summary of the health of Bluewater's assets is depicted in Figure 13.

Figure 13: Health Index Distribution Results Summary of Bluewater's Assets



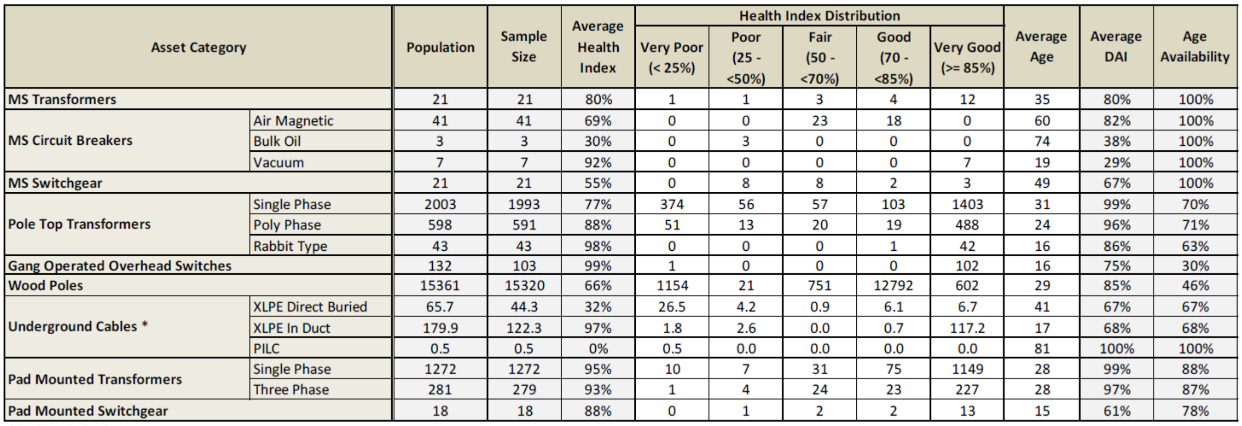
Nine of Bluewater's 16 asset sub-categories listed in Figure 13 have over 80% of their assets in either "good" or "very good" condition. Five of the asset sub-categories have over 90% of the asset units in either "good" or "very good" condition, including: MS Circuit Breakers (Vacuum), Pole Top Transformers (Rabbit Type), Gang Operated Overhead Switches, Underground Cables (XLPE in Duct), and Pad Mounted Transformers (Single Phrase).

Assets of concern were the Underground Cables (PILC and XLPE Direct Buried), Bulk Oil MS Circuit Breakers, MS Switchgear, and Pole Top Transformers (Single Phase). Actions are being taken increase the health of these assets: XLPE Direct Buried cables are being replaced at a rate of approximately 3 km per year under budget UT26; 1.5 km of PILC cable has been eliminated; Bulk Oil breakers in Petrolia are being replaced in 2022 under budget UT77; MS Switchgear is being maintained during overall substation maintenance work and there are replacements under budgets UT75 and UT77; and, transformers are run until failure and then replaced under budgets UT12 and UT47 .

Wood poles are also a concern and focus for the DSP. The Asset Condition Assessment flags 56% of Bluewater's wood poles for action in the next 10 years. Bluewater needs to inspect and/or replace an average of 713 poles each year for the next 20 years, as detailed in Table 23.

Table 29 summarizes the health and age of Bluewater's 9 key distribution asset categories.

Table 29: Health Index Results Summary



Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
MS Transformers		21	21	80%	1	1	3	4	12	35	80%	100%
MS Circuit Breakers	Air Magnetic	41	41	69%	0	0	23	18	0	60	82%	100%
	Bulk Oil	3	3	30%	0	3	0	0	0	74	38%	100%
	Vacuum	7	7	92%	0	0	0	0	7	19	29%	100%
MS Switchgear		21	21	55%	0	8	8	2	3	49	67%	100%
Pole Top Transformers	Single Phase	2003	1993	77%	374	56	57	103	1403	31	99%	70%
	Poly Phase	598	591	88%	51	13	20	19	488	24	96%	71%
	Rabbit Type	43	43	98%	0	0	0	1	42	16	86%	63%
Gang Operated Overhead Switches		132	103	99%	1	0	0	0	102	16	75%	30%
Wood Poles		15361	15320	66%	1154	21	751	12792	602	29	85%	46%
Underground Cables *	XLPE Direct Buried	65.7	44.3	32%	26.5	4.2	0.9	6.1	6.7	41	67%	67%
	XLPE In Duct	179.9	122.3	97%	1.8	2.6	0.0	0.7	117.2	17	68%	68%
	PILC	0.5	0.5	0%	0.5	0.0	0.0	0.0	0.0	81	100%	100%
Pad Mounted Transformers	Single Phase	1272	1272	95%	10	7	31	75	1149	28	99%	88%
	Three Phase	281	279	93%	1	4	24	23	227	28	97%	87%
Pad Mounted Switchgear		18	18	88%	0	1	2	2	13	15	61%	78%

* by length (km)

MS Transformers

Bluewater's system contains 21 municipal station transformers in service; all units had sufficient data for health indexing. The average age of the MS Transformers is 32 years. The average Health Index is 88%. As there is one unit in "poor" and one unit in "very poor" condition, there are two planned replacement of MS transformers in the next 5 years under budgets UT75 and UT77.

Figure 14: MS Transformers Age Distribution

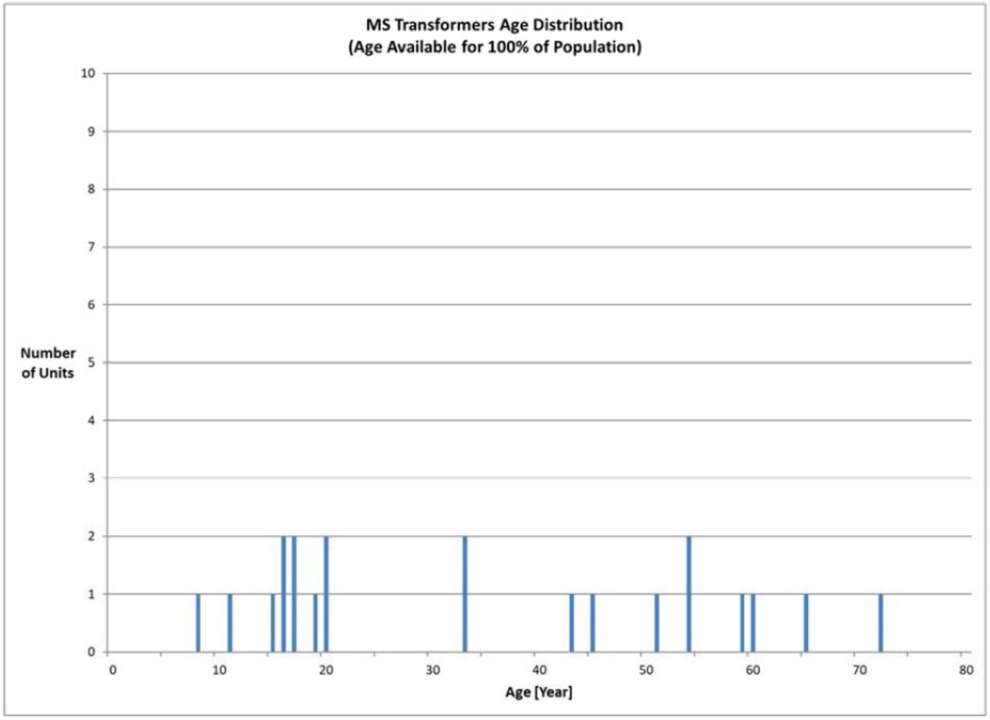
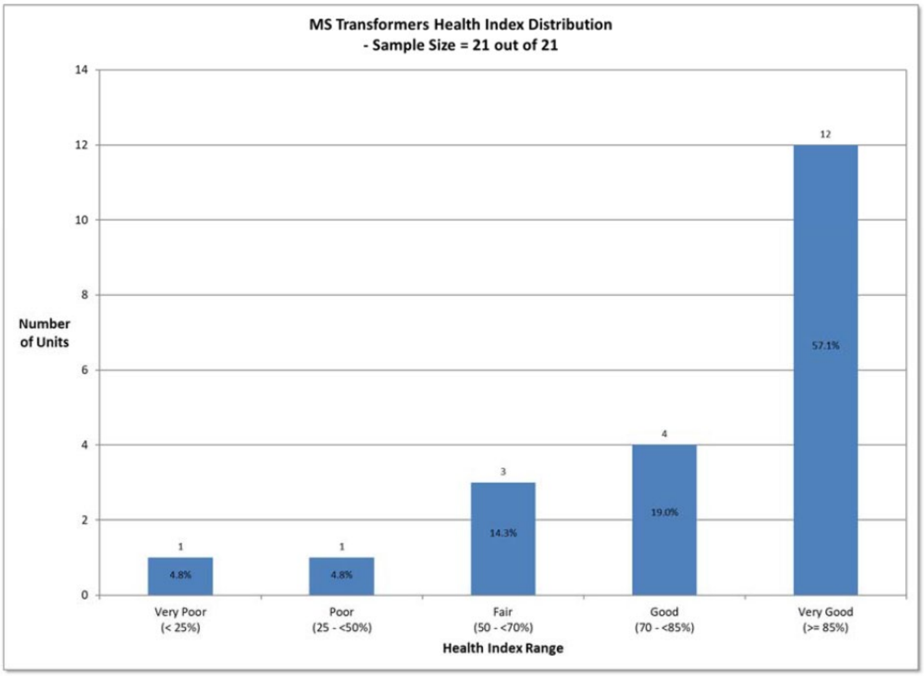


Figure 15: MS Transformers Health Index Distribution



MS Circuit Breakers

Bluewater's system contains:

1. 41 Air Magnetic Circuit Breakers; all units had sufficient data for Health Indexing. The average age is 60 years. The average Health Index is 69%, and none of the population was found to be in "poor" or "very poor" condition.
2. 3 Bulk Oil Circuit Breakers; all units had sufficient data for Health Indexing. The average age is 74 years. The average Health Index is 30%, and the population was found to be in "poor" condition and will be replaced under budget UT77.
3. 7 Vacuum Circuit Breakers; all units had sufficient data for Health Indexing. The average age is 19 years. The average Health Index is 92%, and all of the population was found to be in "very good" condition.

Bluewater does not have plans for replacement of the Circuit Breakers in Fair, Good or Very Good condition in the next 5 years. However, the breakers listed "poor" or "very poor" condition will be replaced along with the MS transformer replacement projects under budget UT77. Table 2-13 in the ACA details the Condition-Based Prioritization List of MS Circuit Breakers.

Figure 16: MS Circuit Breakers Age Distribution

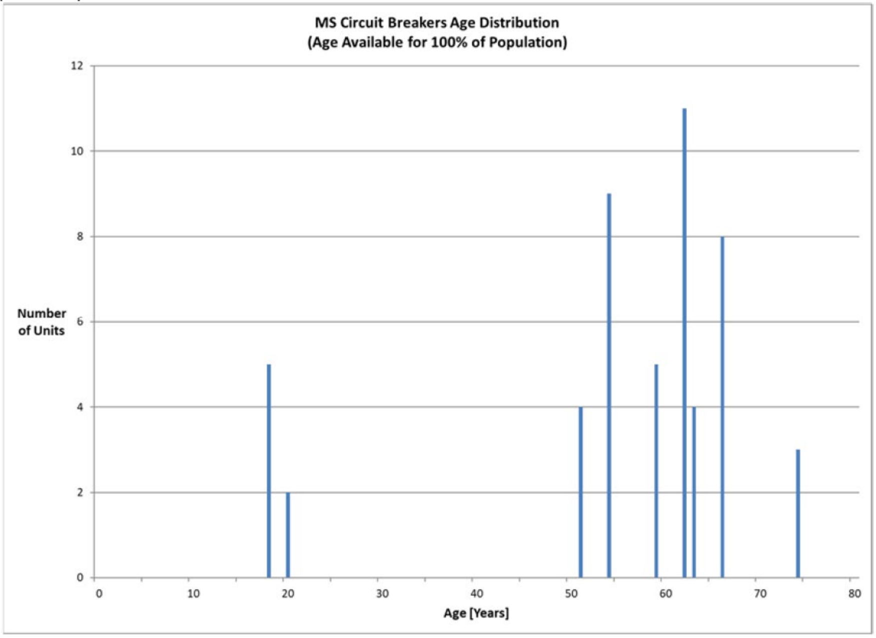


Figure 17: Air Circuit Breakers Health Index Distribution

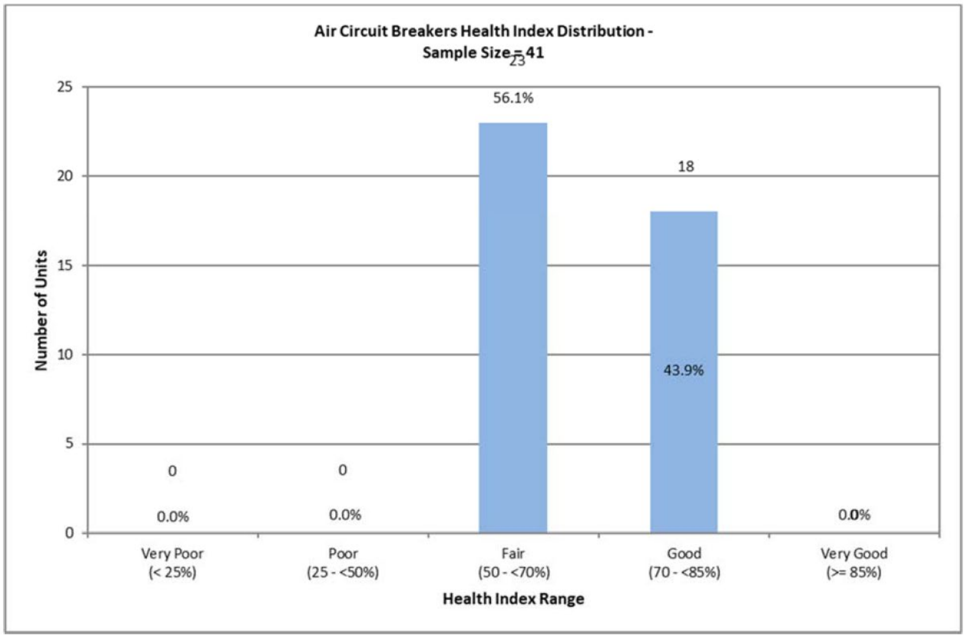


Figure 18: Oil Circuit Breakers Health Index Distribution

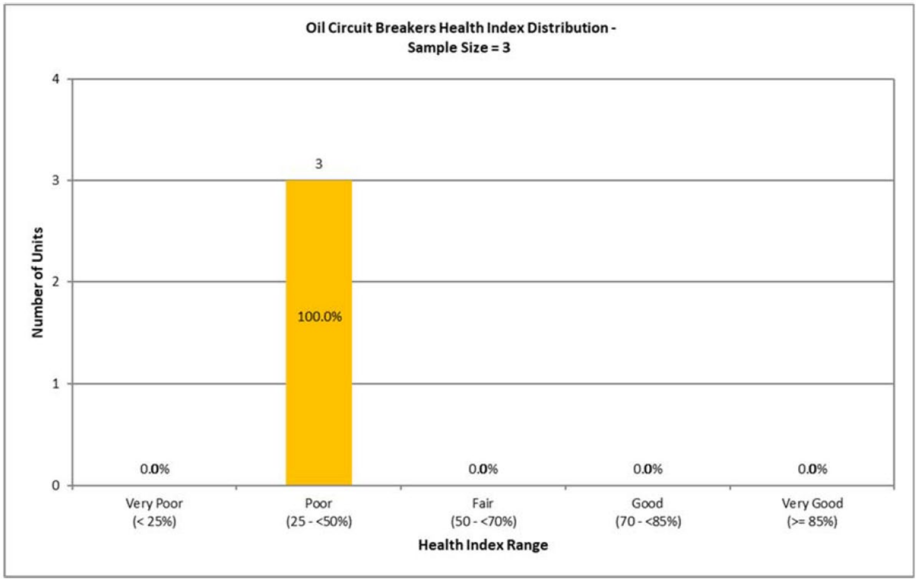
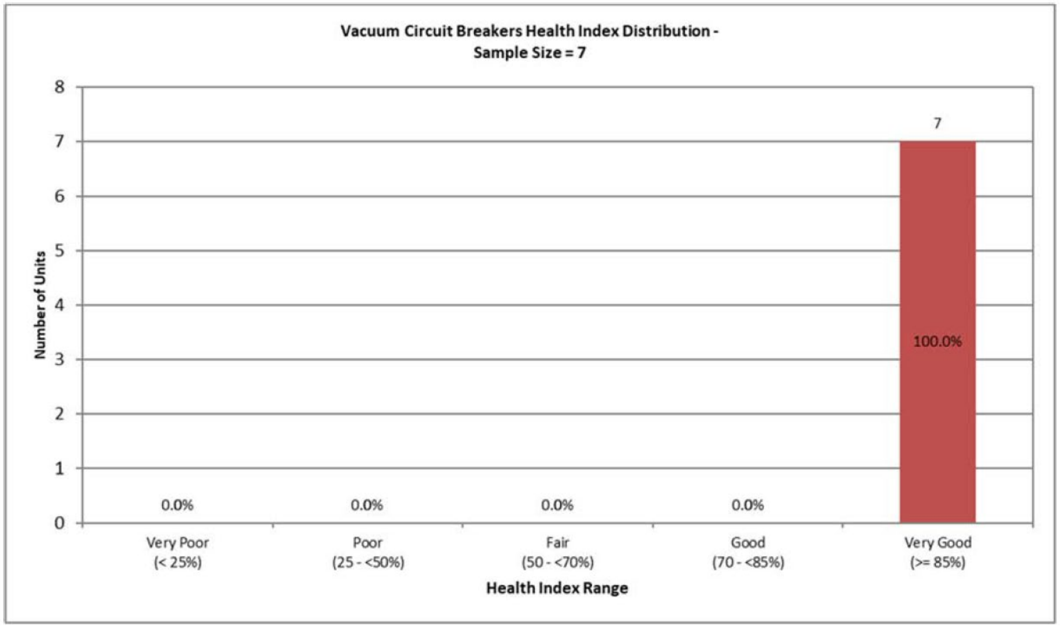


Figure 19: Vacuum Circuit Breakers Health Index Distribution



MS Switchgear

Bluewater's system contains 21 MS Switchgear assets; all units had basic data for Health Indexing. The average age of the MS Switchgear units is 49 years. The average Health Index for this asset group was 55%, and 38% of the population was found to be in "poor" condition.

The probability of failure is over 90% for MS Switchgear. However, as noted on page 65 of the_ACA, a major data gap exists with respect to this asset, in that some units did not have any information other than age. As a result, only limited information is available for MS Switchgear. Bluewater is working to reduce the data gap; at this point, Bluewater's priority is to improve the quality of the data to understand the risk this represents to the system. MS Switchgear is being maintained during overall substation maintenance work and switchgear in one station will be replaced under budget UT77.

Figure 20: MS Switchgear Age Distribution

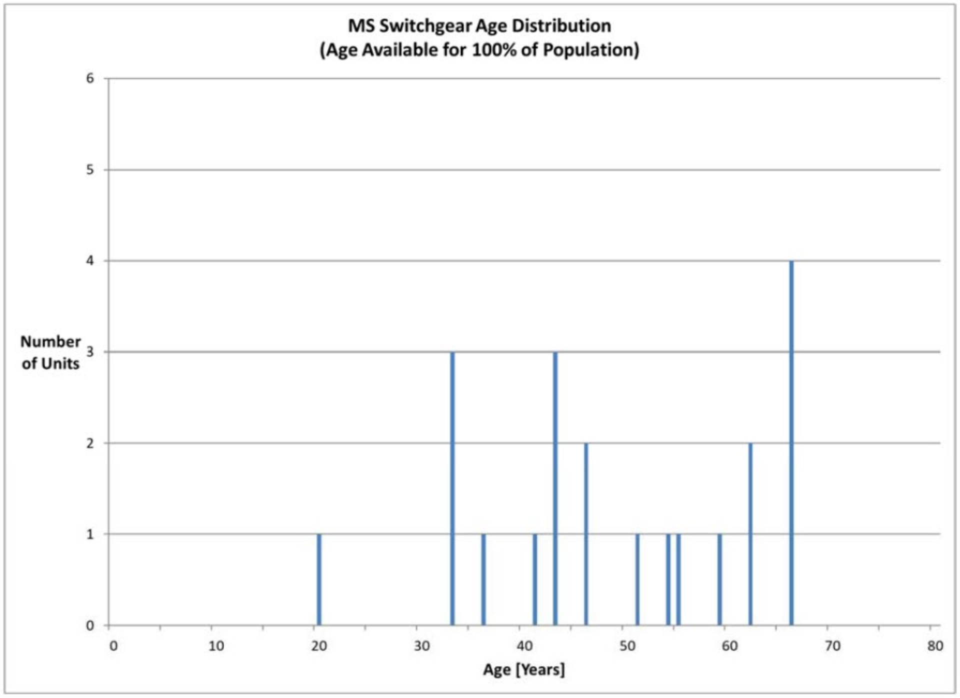
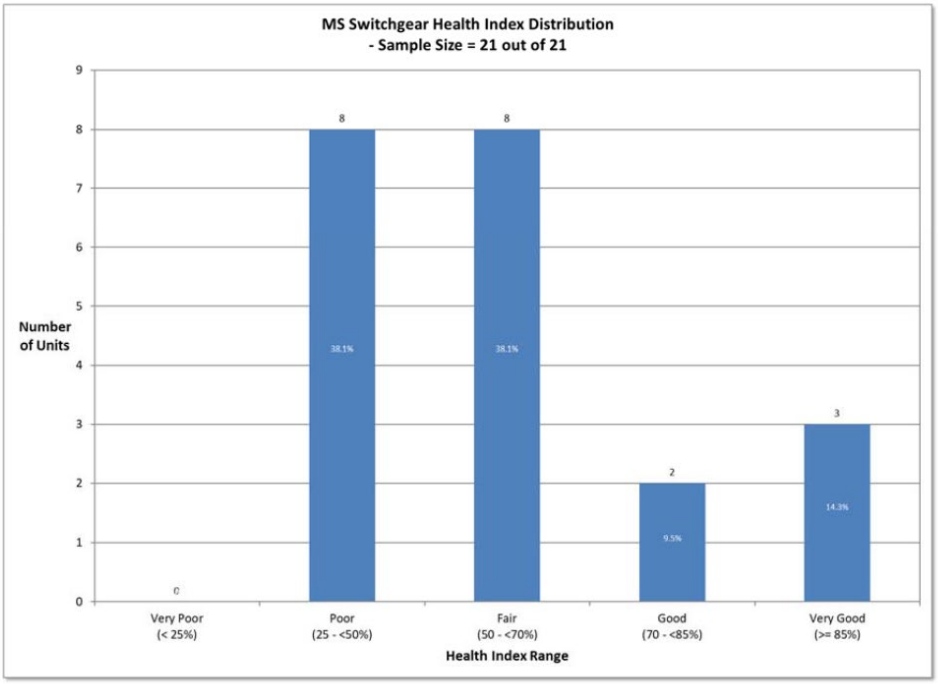


Figure 21: MS Switchgear Health Index Distribution



Pole Top Transformers

Bluewater’s system contains:

1. 2008 Single Phase Pole Top Transformers, of which 1386 units had basic data for Health Indexing. The average age is 31 years. The average health index is 77%, and 21% of the sample was found to be in “poor” or “very poor” condition.
2. 588 Poly Phase Pole Top Transformers, of which 406 units had basic data for Health Indexing. The average age is 24 years. The average health index is 88%, and 11% of the sample was found to be in “poor” or “very poor” condition.
3. 37 Rabbit Type Pole Top Transformers, of which 20 units had basic data for Health Indexing. The average age is 16 years. The average health index is 98%, and none of the sample was found to be in “poor” or “very poor” condition.

Pole top transformers are replaced when the asset fails. Bluewater’s reactive philosophy with pole top transformers is to run to failure. Bluewater does not have the capability to directly track pole top transformer health and therefore does not have the data needed to take a proactive approach. The impact to the system of failures like these are manageable. Bluewater looks to balance costs, and the budget does not allow proactive replacement of pole top transformers.

Figure 22: Pole Top Transformer (Single Phase) Age Distribution

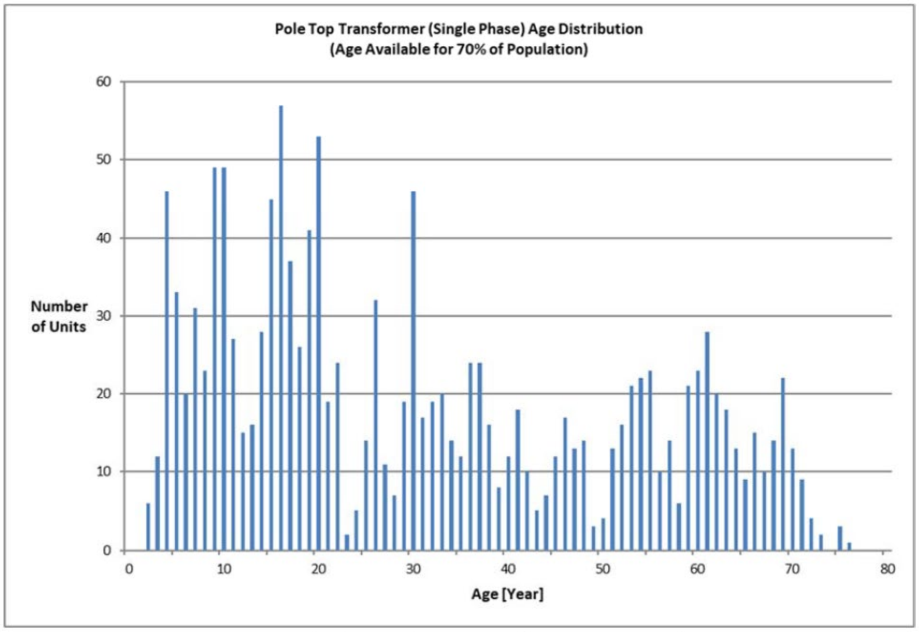


Figure 23: Pole Top Transformer (Single Phase) Health Index Distribution

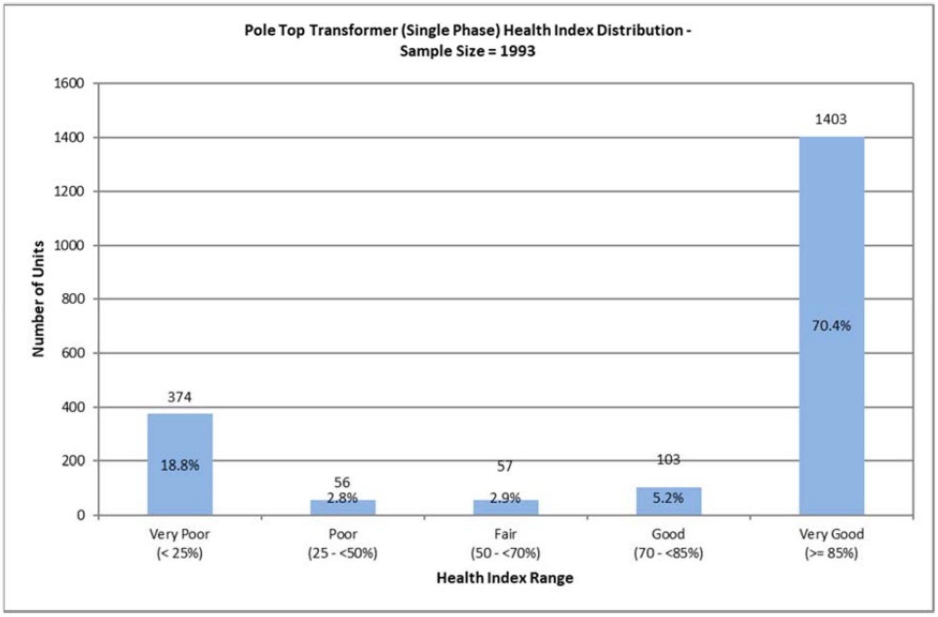


Figure 24: Pole Top Transformer (Poly Phase) Age Distribution

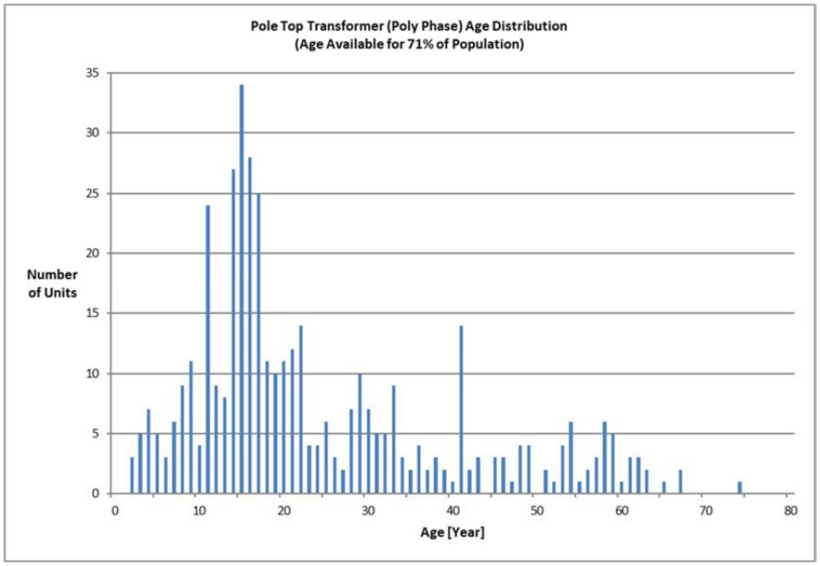


Figure 25: Pole Top Transformer (Poly Phase) Health Index Distribution

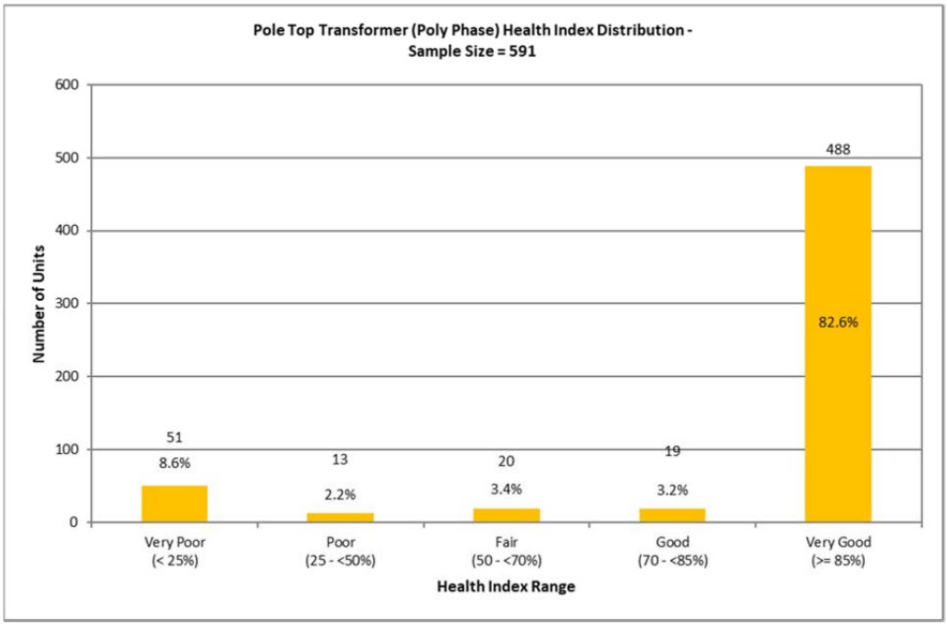


Figure 26: Pole Top Transformer (Rabbit Type) Age Distribution

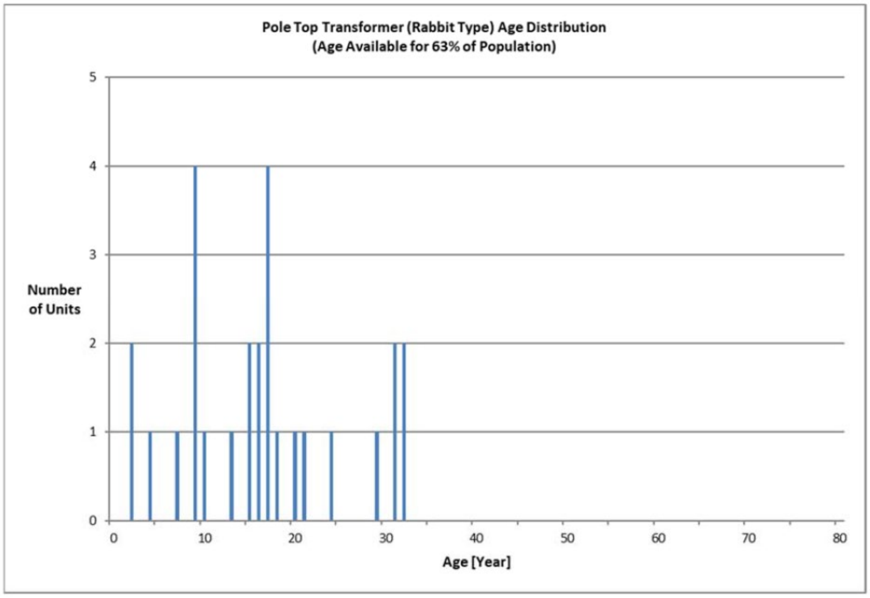
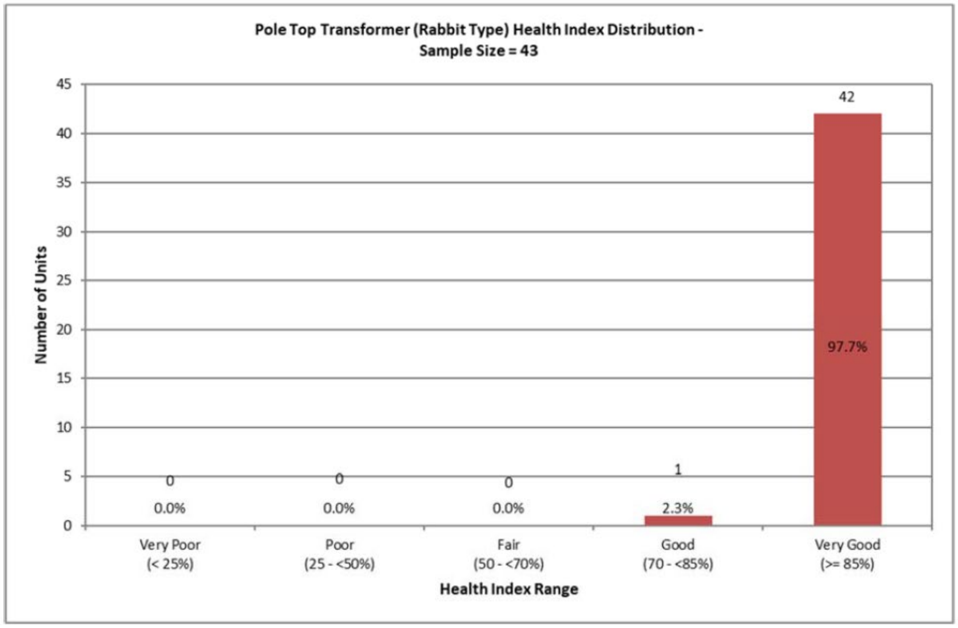


Figure 27: Pole Top Transformer (Rabbit Type) Health Index Distribution



Gang Operated Overhead Switches

Bluewater's system contains 132 Manual Gang Operated Overhead Switches, of which 103 units had basic data for Health Indexing. The average age of units is 13 years. Motorized switches did not have age data. The average Health Index is 99%, and none of the units were found to be in "poor" or "very poor" condition.

Figure 28: Gang Operated Overhead Switches (Manual) Age Distribution

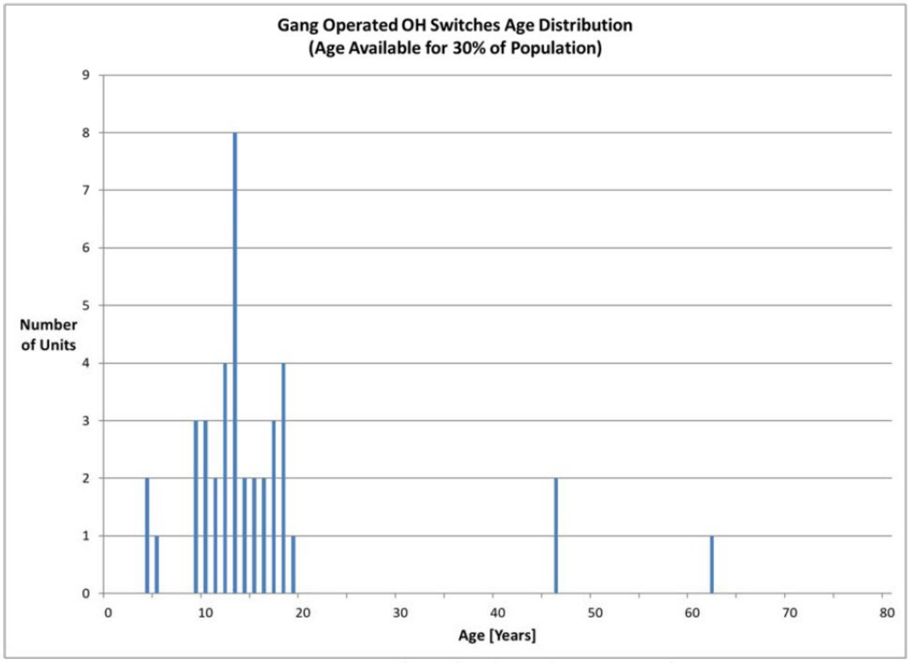
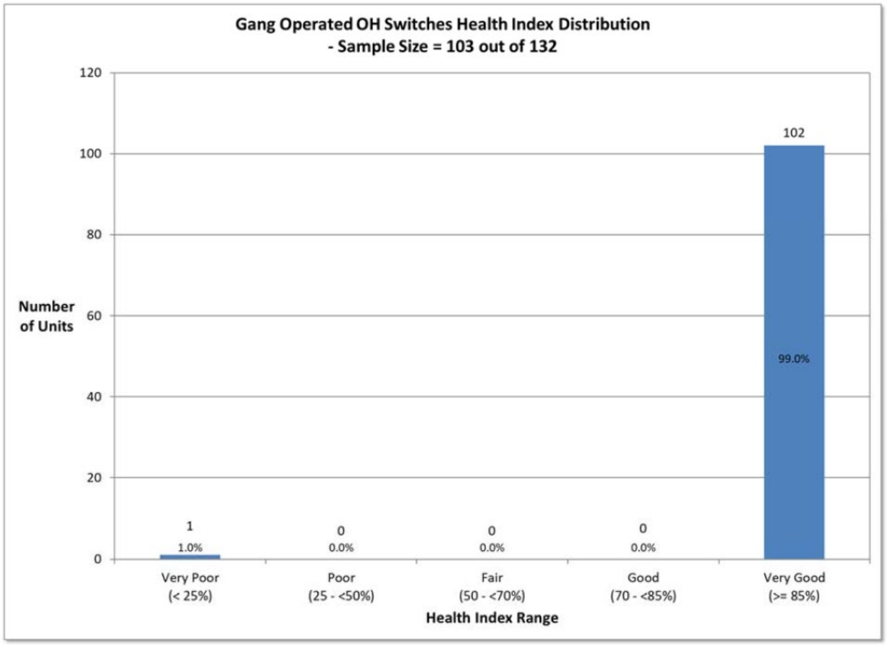


Figure 29: Gang Operated Overhead Switches Distribution



Wood Poles

As per the 2020 ACA, Bluewater's system contains 15,361 wood poles in service, of which 15,320 units had at least basic data for Health Indexing. The average age of the poles with a known age is 29 years. The average health index of the poles is 66%, with 8% in "poor" or "very poor" condition.

Although the wood pole population seems to be in an overall "good" condition, the Asset Condition Assessment explains at page 25 that "there are concerns with the 'good' classification in the data" for wood poles. In particular, age data is only available for 46% of the population, and inspection data collected is typically based on an overall, full pole assembly, rather than solely the wood pole.

As such, since 2017, Bluewater has increased the number of inspections and testing of its wood pole population to gain a better understanding of their condition. The poles are inspected with a resistograph on a 10-year cycle. The ACA confirms that of the approximately 4,740 wood poles that Bluewater has tested for cavity and decay, a failure rate of approximately 8% was found for such a subset of the entire population.

Numerous poles have reached their end of useful life due to a period of rapid construction during Sarnia's "boom time" in the 1960s and 1970s. The Asset Condition Assessment has flagged-for-action an average of 714 poles each year for the next 20 years. Flagged-for-action does not mean replacement, but is a guiding principle that 714 poles are near end of life and require close inspection. Actual replacements are based on testing results.

It is because of this background that spending on wood pole replacement has increased almost ten-fold when compared to the 2013 budget, and Bluewater expects the current level of spending on wood pole replacement will remain roughly the same for the foreseeable future. Bluewater has budgeted (UT15) to replace approximately 190 poles in 2023, which includes adjacent poles that are occasionally replaced out of efficiency. This number represents approximately 1.2% of poles are being replaced each year and poles are selected systematically visual inspections and the resistograph testing. Bluewater believes this level of spending is reasonable to ensure system reliability.

Customer engagement has traditionally confirmed that customers believe that it's best to replace deteriorating equipment, such as rotten poles, before it breaks down for continued reliability.

Figure 30: Wood Poles Age Distribution

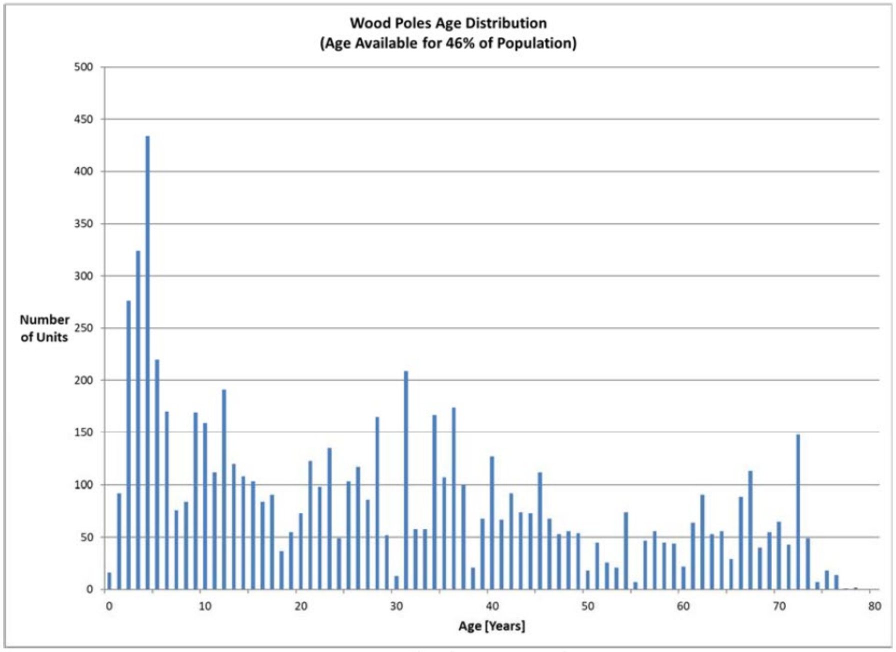
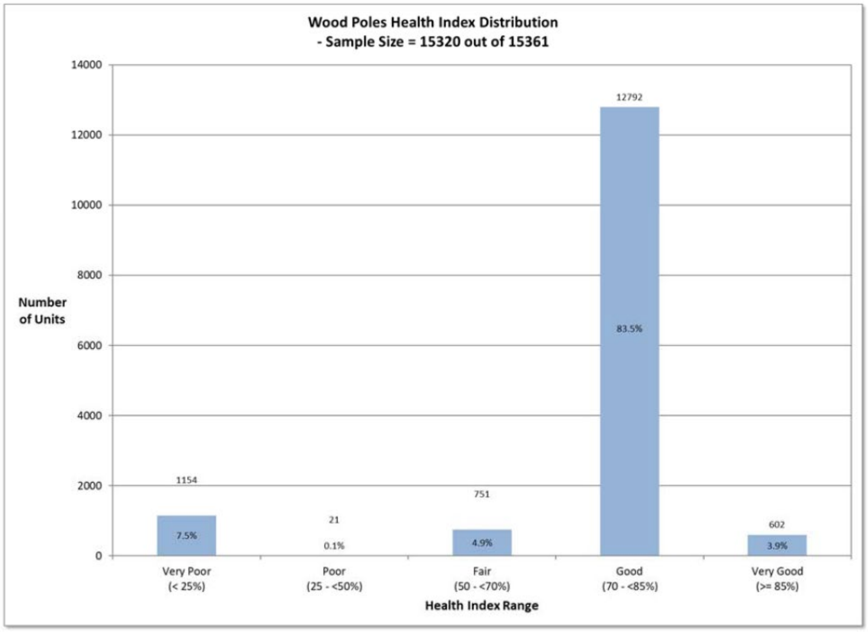


Figure 31: Wood Poles Health Index Distribution



Underground Cables

Bluewater's system contains:

1. 67 conductor-km of XLPE Direct Buried Underground Cables, of which 45 conductor-km had basic data for Health Indexing. The average age is 41 years/conductor-km. The average health index was 32%, and 70% of the sample was in "poor" or "very poor" condition.
2. 184 conductor-km of XLPE In-Duct Cables, of which 125 conductor-km had basic data for Health Indexing. The average age is 17 years/conductor-km. The average health index is 97% with 4% of the sample in poor or very poor condition.
3. 0.5 conductor-km of PILC Cables In-Duct, all of which had basic data for Health Indexing. The average age is 81 years per conductor-km. The average health index is 0% with all of the population in "very poor" condition.

Bluewater balances proactive and reactive replacement of underground cables. Cables located in duct or lead cables are treated as reactive in nature. When cable is in duct, it can easily be pulled out and replaced if there is a failure. With lead (PILC) cable, there is only 0.5 km of cable, so it is best to wait until failure for replacement.

The target areas are underground subdivisions where the primary cables have reached their end of usable life as a result of age and in some instances, cable has deteriorated to the point where cable failures have occurred. This replacement is reflected in the primary cable replacement budget, UT26 as well as PILC replacement budget UT35. Bluewater Power is confident these strategies will keep us ahead of the curve with cable failures and help to maintain our reliability.

Figure 32: Underground Cables (XLPE Direct Buried) Age Distribution

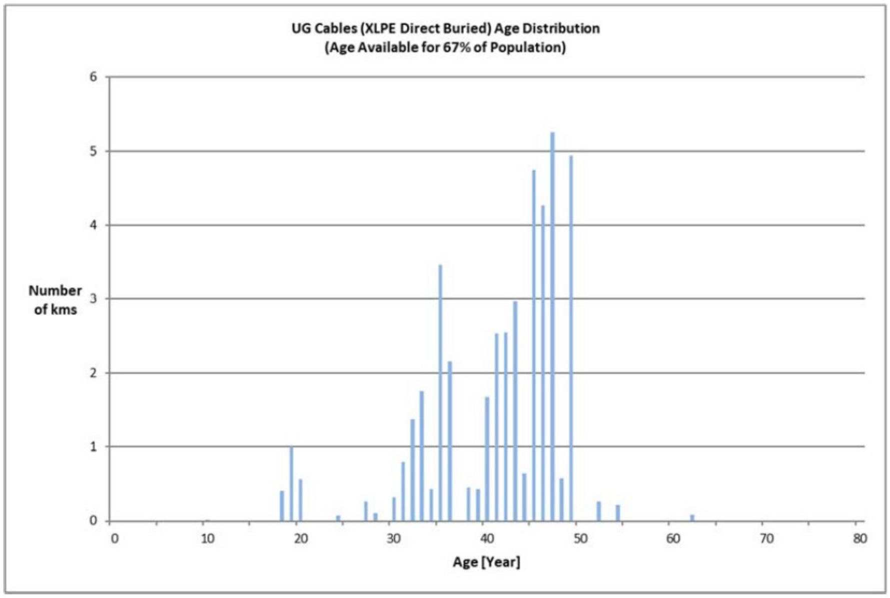


Figure 33: Underground Cables (XLPE Direct Buried) Health Index Distribution

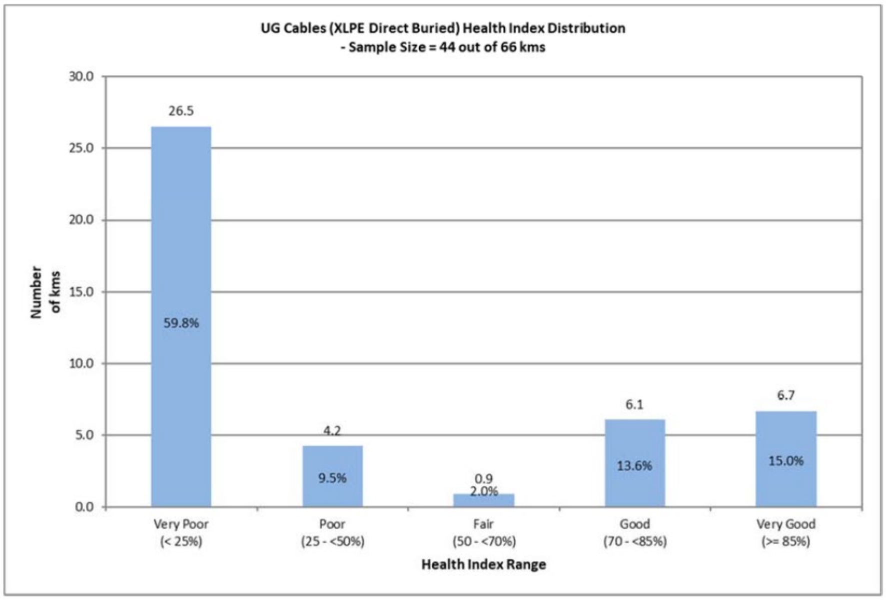


Figure 34: Underground Cables (XLPE In-Duct) Age Distribution

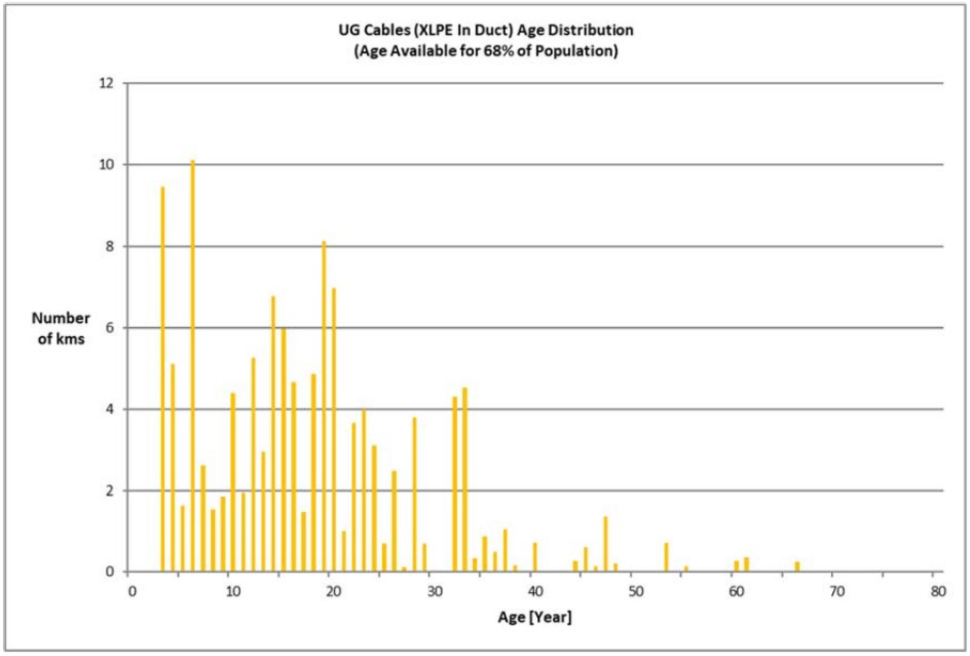


Figure 35: Underground Cables (XLPE In-Duct) Health Index Distribution

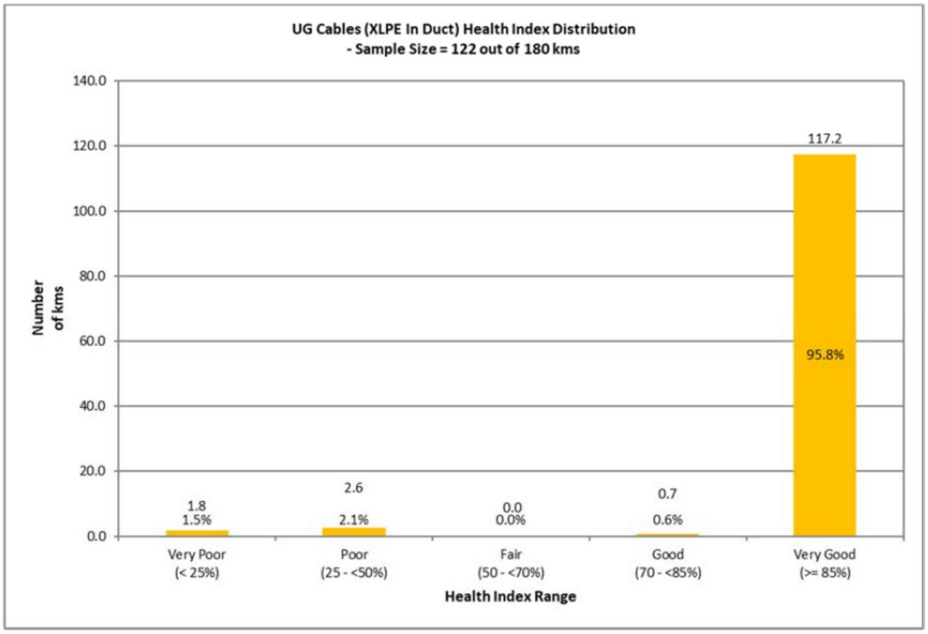


Figure 36: Underground Cables (PILC In-Duct) Age Distribution

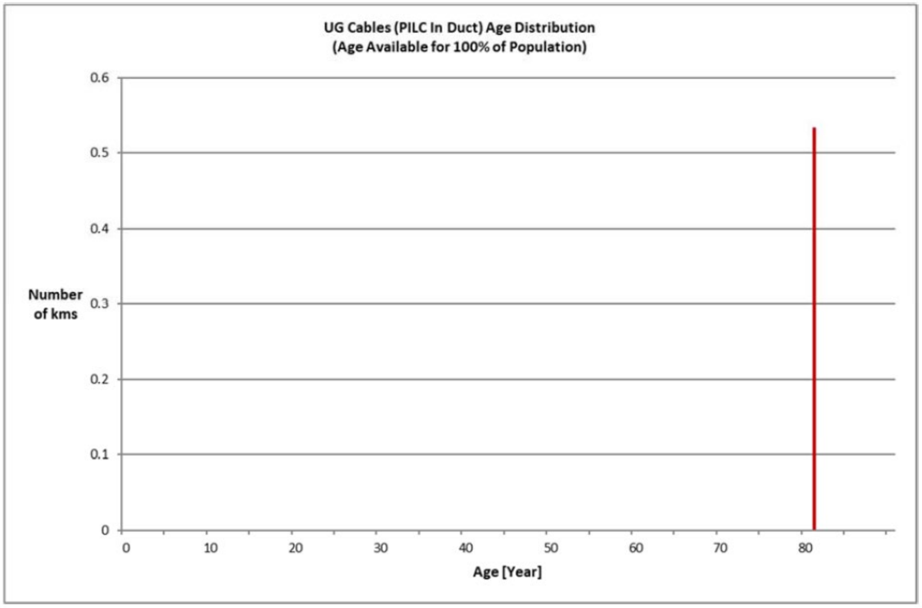
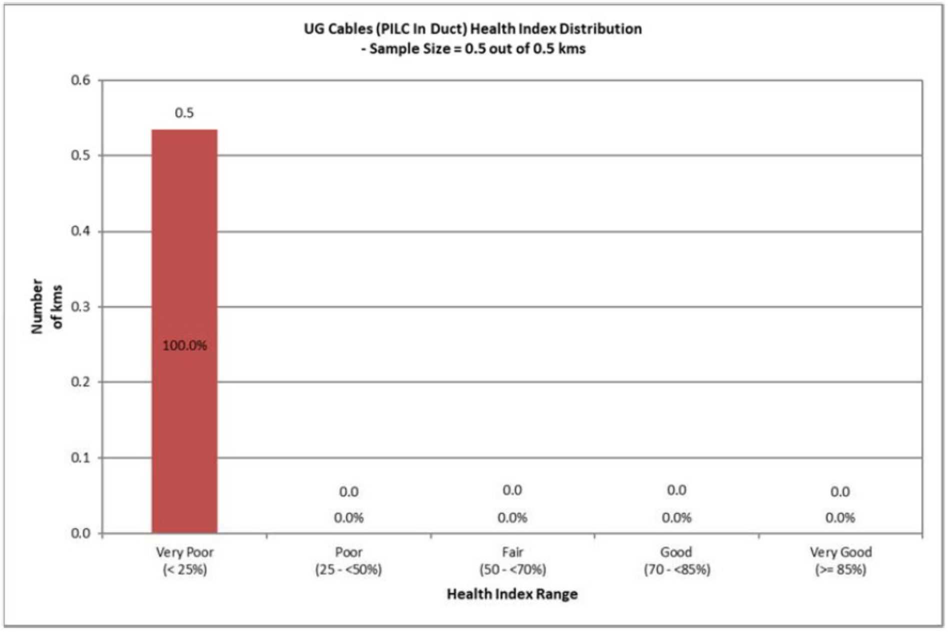


Figure 37: Underground Cables (PILC In-Duct) Health Index Distribution



Pad Mounted Transformers

Bluewater's system contains:

1. 1,272 single phase Pad Mounted Transformers, all of which had basic data for Health Indexing. The average age is 28 years. The average Health Index is 95% and less than 2% were found to be in "poor" or "very poor" condition.
2. 281 three phase Pad Mounted Transformers, of which 279 units had sufficient data for Health Indexing. The average age is 28 years. The average Health Index is 93%, and 1% of the samples were in "poor" or "very poor" condition. These assets are inspected yearly per the DSC.

Figure 38: Pad Mounted Transformers (Single Phase) Age Distribution

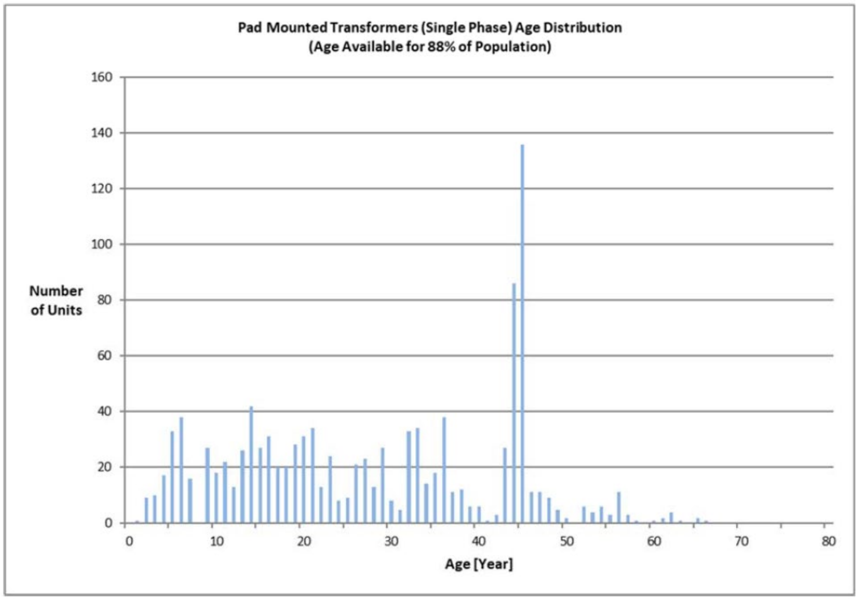


Figure 39: Pad Mounted Transformers (Single Phase) Health Index Distribution

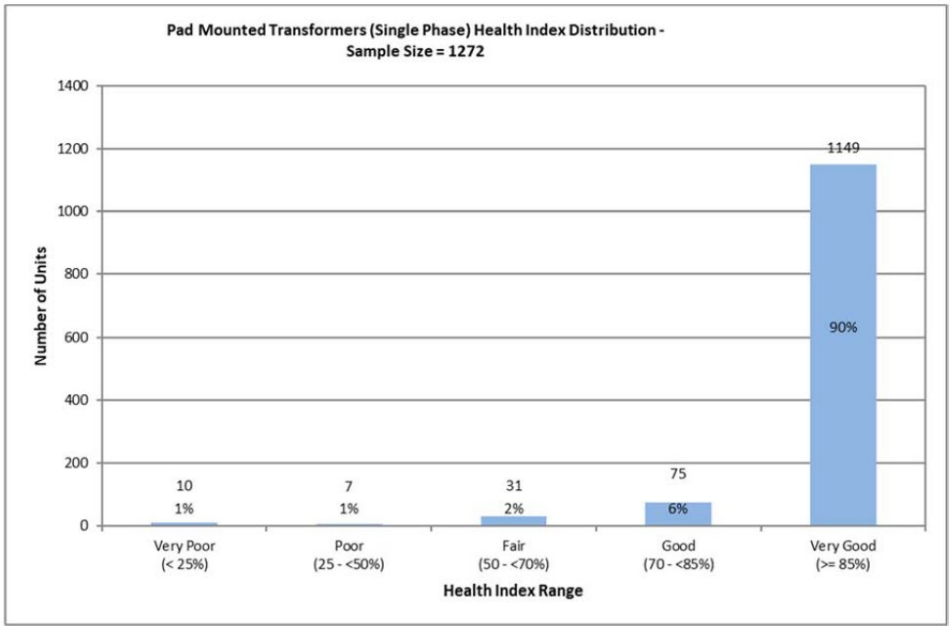


Figure 40: Pad Mounted Transformers (Three Phase) Age Distribution

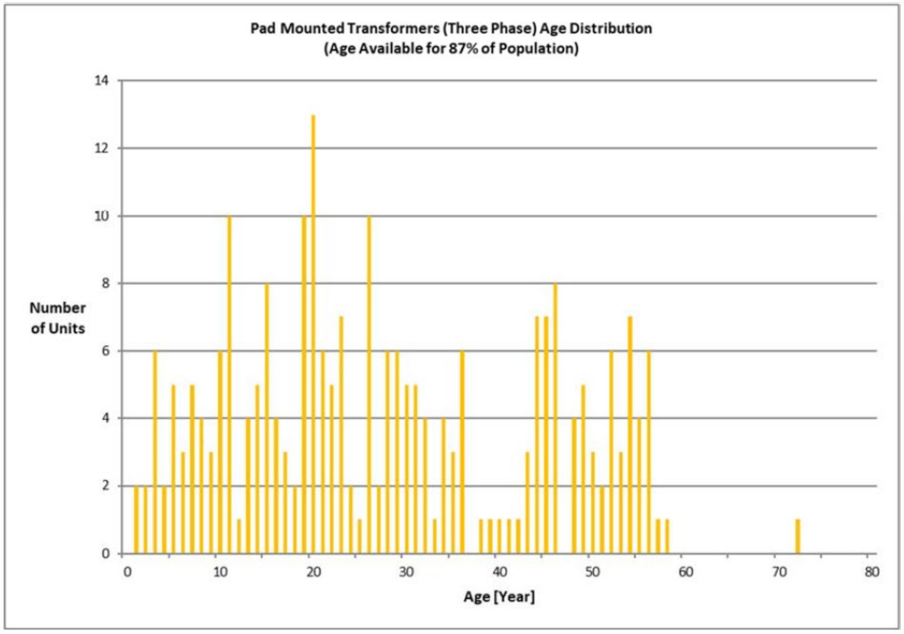
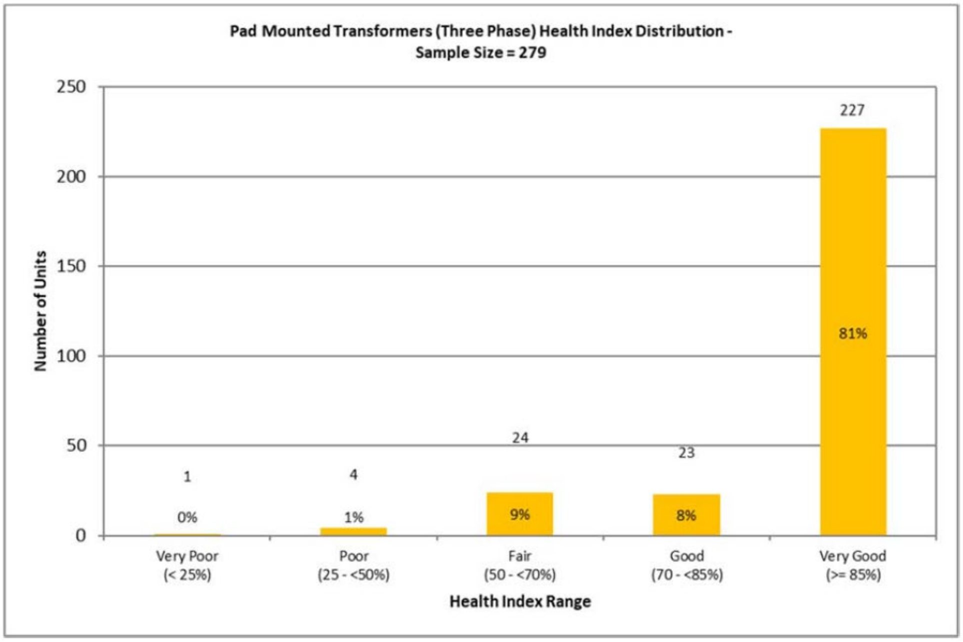


Figure 41: Pad Mounted Transformers (Three Phase) Health Index Distribution



Pad Mounted Switchgear

Bluewater's system contains 18 Pad Mounted Switchgear units; all units had basic data for Health Indexing. The average age is 15 years. The average Health Index for these assets is 88%, with one unit found to be in "poor" or "very poor" condition.

Figure 42: Pad Mounted Switchgear Age Distribution

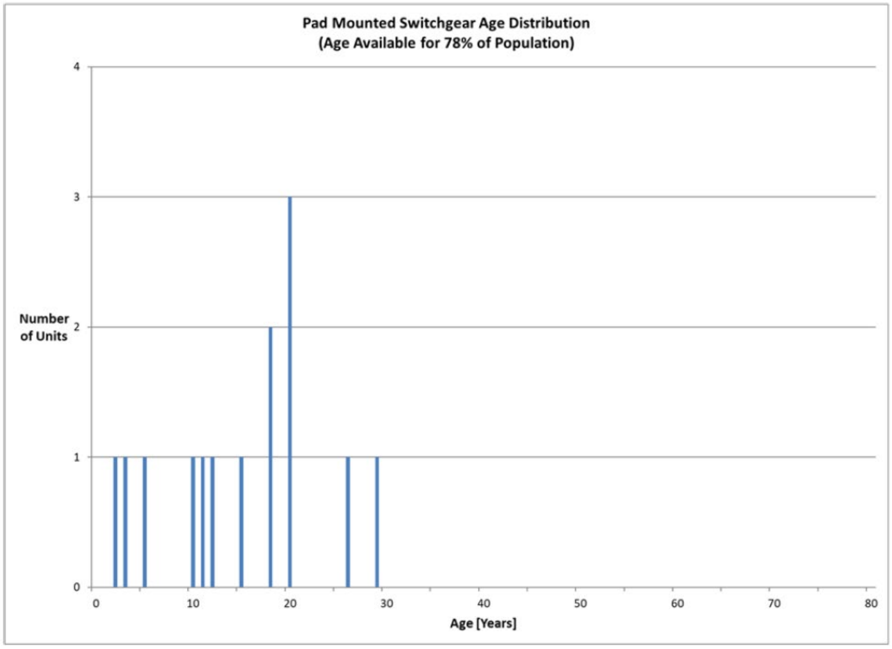
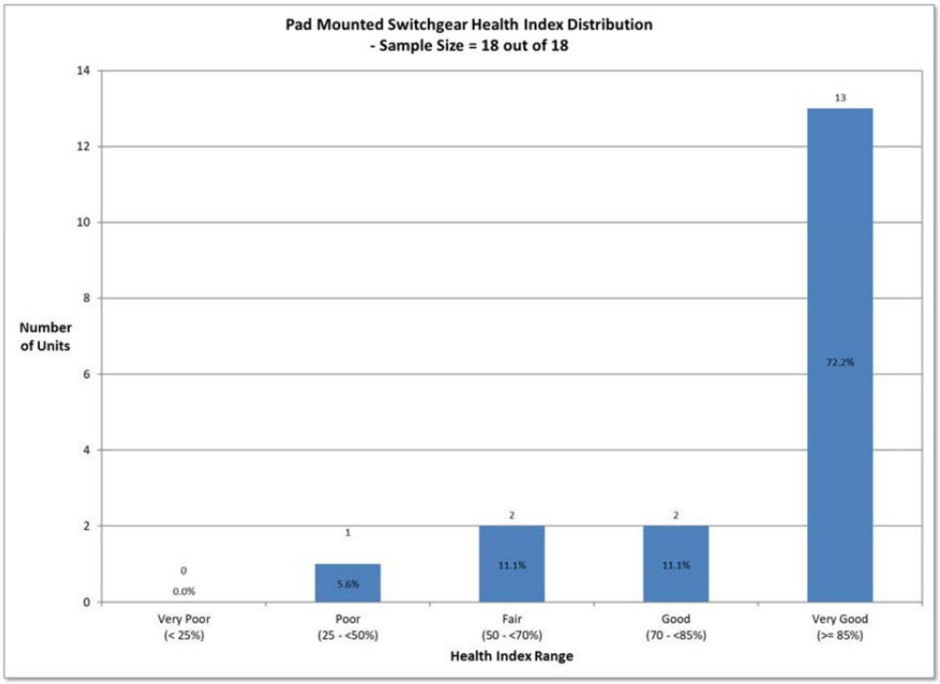


Figure 43: Pad Mounted Switchgear Health Index Distribution



Fleet

Bluewater's fleet assets consist of 55 vehicles, 14 trailers, and 11 pieces of specialty power-operated support equipment. Fleet assets have been divided into 5 categories, as shown in the table, below. A detailed list of Bluewater's fleet inventory may be found in Section 3 of Fleet Management Plan.

Table 30: Fleet Inventory

Vehicle Type	Number of Vehicles in Fleet
Heavy Duty Boom	17
Medium Duty	14
Light Duty	24
Trailers	14
Support Vehicles	11

5.3.2.3 Transmission or High Voltage Assets

Bluewater does not have any transmission or high voltage assets.

5.3.2.4 Host or Embedded Distributor

Bluewater is partially embedded in the Hydro One Networks Inc.'s distribution area. Approximately 10% of Bluewater's load comes from Hydro One and 90% from the IESO grid.

5.3.3 Asset Lifecycle Optimization Policies and Practices

As this is Bluewater's first DSP, there is no comparison of changes to policies and processes with a prior DSP.

Bluewater plans for investments as part of the asset management process with an updated ACA and a proposed budget envelope as described in 5.3.1 Planning Process.

5.3.3.1 Asset Lifecycle Optimization

ASSET REPLACEMENT AND REFURBISHMENT POLICIES

Bluewater identifies deficiencies and hazards during inspections and condition assessments. In conducting inspections and condition assessments, Bluewater divides its service territory into urban and rural sub-areas based on the location, relative population density, and in accordance with the OEB's definitions of urban and rural. The regions form the basis for Bluewater's systematic vision patrols. Inspections are such that one-third and one-sixth of the urban and rural service territory, respectively, are inspected on an annual basis, thereby having inspected the whole urban and rural distribution system on a three and six-year cycle. Underground patrol is performed concurrently with the patrol of the overhead distribution system.

In addition to routine visual patrols, several maintenance practices further contribute to the assessment, such as thermographic imaging. Feeder inspections and dry-ice cleaning serve as secondary visual inspections. The inspection of vegetation is included as a component of the visual patrol.

Assets are replaced only when their condition indicates a replacement is the best option due to risk and criticality. The ACA's Health Index and Flagged-for-Action tools are used in this regard.

The Health Index quantifies equipment condition based on numerous condition parameters that are related to the degradation factors that lead to an asset's end of service life. Health Index is an indicator of the asset's overall health and is given in terms of a percentage, with 100% representing an asset in brand new condition.

The ACA's Flagged-for-Action results are used as a guide for Bluewater's planning process, but is not the final deciding factor in making sustainment capital decisions. Numerous other factors, such as asset condition, safety, obsolescence, system expansion, regulatory requirements, and municipal demands also influence asset replacement plans.

When an asset is Flagged-for-Action, additional analysis takes place to determine the appropriate corrective action. If determined asset replacement is the right action to take, then overall urgency and priority (in context of all Bluewater work) is determined. Replacement options are then reviewed (such as combining with other projects, eliminate through voltage conversion, relocate to accommodate future road widening, etc.).

5.3.3.2 System Operations and Maintenance Activities

Overhead Distribution System

Bluewater's overhead distribution system accounts for approximately 75% of its overall distribution system. The overhead portion of the distribution system is comprised primarily of poles, conductors, distribution transformers and protective devices.

Pole Mount Transformers

Inspection and Condition Assessments

Inspection of overhead distribution transformers is included in the visual patrol of the overhead distribution system, inspected on a three-year cycle in urban areas and a six-year cycle in rural areas.

Maintenance and Sustainment

Thermographic imaging is performed on transformers annually.

Condition-based maintenance on the overhead distribution system is performed as a result of the visual patrol/condition assessment of transformers, completed by the System Inspection Powerline Technician or other qualified person ("Asset Inspector"), or as identified during predictive and preventive maintenance programs.

Transformers are planned for repair or replacement based on the risk rating determined by the Asset Inspector. Immediate repair or replacement is completed if hot spots or other damage or deterioration (oil leaks, excessive rust) is noted.

Overhead Switches

Switches on Bluewater's overhead distribution system include fused in-lines, air-break/load-break switches, dead-blade switches and fused switches, typical of protection for lateral feeds or for transitions between overhead and underground distribution.

Inspection and Condition Assessments

Following the general practice of inspection of the overhead distribution system, switches are also inspected on a three and six year cycle within urban and rural settings, respectively.

As with poles and distribution transformers, the attributes of a switch are verified, including the type of switch, operating voltage, pole number on which the switch is mounted or in close proximity to, and switch identification number. A condition assessment is also visually performed of the switch and hardware components (such as lightning arrestor, connection locks) to determine if deficiencies or hazards exist

Switches may also be inspected, and deficiencies/hazards documented, during annual infrared thermography of the overhead distribution system.

Maintenance and Sustainment

Thermographic imaging is performed annually on switches.

Switches are planned for repair or replacement based on the risk rating determined by the Asset Inspector. Immediate repair or replacement is completed if hot spots or other damage or deterioration (chipped insulators, excessive rust) is noted.

Poles

The majority of poles in Bluewater's distribution system are wood of varying species. Less than one percent is constructed from concrete, steel, or aluminum.

Inspection and Condition Assessments

Inspection of poles is included in the visual patrol of the overhead distribution system, inspected on a three-year cycle in urban areas and a six-year cycle in rural areas.

During the inspection, a visual assessment is performed to confirm the documented attributes of the pole. For each pole, the height, class, manufacture date, owner and pole identification number are verified. Where a discrepancy exists, the inspector documents the field attributes. Poles are subsequently inspected to determine superficial condition; that is, each pole is examined to ensure it is not broken and/or rotten, and to ensure grading around the base of the pole is adequate.

Deficiencies or hazards on the pole or any one of the components (such as cable guards, cross arm, hardware, guys) identified during the patrol are noted to indicate that corrective action is required.

Following the visual inspection (and testing, where appropriate as noted below) poles are assigned a Risk Rating within the inspection table. Rotten poles or poles that present an imminent threat to health, safety or the environment are assigned the highest risk rating. Generally, tested poles are rated either as the highest priority (red) or the lowest priority (green); however, poles may also be assigned a Risk Rating between these two priorities based on the assessment of other components on the pole. Where the pole's degree of risk is of the highest priority the inspector immediately notifies a Line Supervisor to initiate corrective action.

Pole testing may be conducted during the inspection, without delay, by the Asset Inspector for poles that are visibly split or decayed. Furthermore, poles considered to be rotten, primarily based on age or other factors as determined by the inspector based on experience and training as an Asset Inspector are also tested to ascertain condition.

Prior to 2017, resistograph testing complemented the visual assessment only where the visual assessment identified poles that required further inspection. Poles on main arterial roads were also inspected with this device.

Since 2017, Bluewater has undertaken a systematic approach to resistograph pole testing, with the intent to test 100% of the poles over time in order to gain a baseline of data. Results of the inspections show an 8% failure rate of decay and cavity for wood poles. In 2023, Bluewater plans to replace approximately 190 wood poles as part of the Wood Pole Replacement Program (see Appendix F).

The number of wood poles that Bluewater plans to replace in 2023 is based on the results from pole testing, both visual inspections and resistograph tests, as well as historical failures. Bluewater paces its wood pole replacements reasonably to mitigate impacts to customers while addressing system needs; replacing approximately 190 poles per year achieves that balance.

The resistograph measures the degree of decay and remaining wall thickness, thereby quantifying the structural integrity of the pole. It is configured to test for both decay and cavity detection at standards recommended by the manufacturer. The width of a decay area must be at least ½ inch to be detected as decay. Decay in the range of 0%-35% qualifies as a pass; 36%-60% qualified as a marginal pass, and 61% and above is qualified as a fail. The width of the cavity area must be at least ½ inch to be detected as a cavity. A cavity in the range of 0%-15% qualifies as a pass; 16%-20% qualifies as a marginal pass; 21% and above qualifies as a fail.

The resistograph allows for the pole identification number and test date to be documented, as well as comments the inspector may include. With the use of the resistograph, the pole test results may be printed for review onsite. Consequently, the inspector is able to immediately determine the pole condition. The results of pole testing are documented by the inspector within a pole testing table, specific to the pole, and electronically by the resistograph; the results are then archived.

Maintenance and Sustainment

Condition-based maintenance on the overhead distribution system is performed as a result of the visual patrol/condition assessment, completed by the Asset Inspector, or as identified during predictive and preventive maintenance programs as noted above.

Primary Overhead Conductor

Inspection and Condition Assessments

Inspection of overhead distribution transformers is included in the visual patrol of the overhead distribution system, inspected on a three-year cycle in urban areas and a six-year cycle in rural areas.

Secondary conductors (overhead and underground) are not separately inspected or maintained, and are run to failure (replaced upon third fault – i.e. max of two repairs).

Infrared scans are completed annually. Tree trimming is completed once every 4 years.

<u>Maintenance and Sustainment</u>

Planned repair or replacement based on the risk rating determined by the Asset Inspector; immediate repair or replacement if damage or deficiencies noted during inspection or patrol (hot spots, broken strands).

Poleline Hardware (cross arms, pins, insulators, brackets, etc.)

<u>Inspection and Condition Assessments</u>

Inspection of overhead distribution transformers is included in the visual patrol of the overhead distribution system, inspected on a three-year cycle in urban areas and a six-year cycle in rural areas. Infrared scans occur every year.

<u>Maintenance and Sustainment</u>

Overhead electrical equipment is often subject to contamination from various factors such as industrial emissions, but primarily road salt spray. Of particular concern to the reliability of the distribution system is salt contamination on overhead glass insulators. Over time, salt accumulates and increases conductivity across the insulator; under wet conditions the conductive layer may initiate leakage current, causing flashovers and potentially resulting in a relay operation or line outage.

To mitigate such contamination, reduce outages and ultimately enhance reliability, Bluewater used the services of a contractor for insulator washing. This preventive maintenance practice occurred annually on all glass insulators installed on the 27.6 kV distribution system. Insulator washing was initiated through the issuance of a work order by the Line Supervisor. During the washing, a condition-assessment of the insulator and other overhead assets/components along the pole line was also performed and deficiencies (such as broken/cracked insulators) were documented. The contractor was able to identify deficiencies and evaluate the urgency of a deficiency, or the potential impact to health and safety. While all deficiencies are documented on the work order, the contractor also immediately notified the Line Supervisor of critical/urgent deficiencies, such as a blown arrestor or broken tie wire. The Line Supervisor may have also performed an on-site assessment of the deficiency or alternatively, issued another work-order and dispatch a Journeyperson Powerline Technician for condition-based maintenance to immediately remediate critical deficiencies or hazards.

Following insulator washing, the Line Supervisor reviewed the documented deficiencies and prioritized items for corrective action. A second work order for condition-based maintenance was also issued by the Line Supervisor for remediation of these remaining, non-critical deficiencies, whereby higher priority items were first addressed, followed by lower priority items, addressing all items on the work order within approximately one month. Bluewater is now in a position where enough of its glass insulators have been replaced with polymer insulators and this program is no loner necessary.

Also completed by a contractor/arborist, the preventive maintenance practice of vegetation management (also known as “tree trimming”) is performed on the overhead distribution system in both urban and rural areas on a four-year cycle.

Assets are planned for repair or replacement based on the risk rating determined by the Asset Inspector. There is immediate repair or replacement completed if there is damage or deficiencies noted during inspection or patrol (excessive rusting, physical damage, overheating, etc.).

Underground Distribution System

Primary Underground Cable

Most underground cable in Bluewater’s territory was installed in the early 1970s as a result of an increase in residential subdivision development at that time. Today, much of this cable is nearing or at its end-of-life, the consequence of which is anticipated or actual cable failures. Bluewater recognizes this and has implemented an underground cable replacement program to mitigate such failures and resultant decrease in performance and reliability.

Inspection and Condition Assessments

Visual inspection of underground cables is limited to terminations and portions of cable visible in transformers, switchgear and vaults. A visual inspection is completed once every 7 years.

Maintenance and Sustainment

The underground cable replacement program is one of both reactive and proactive measures. Prior to failure, Bluewater reviews its subdivisions and prioritizes cable replacements based on various factors, but primarily the age of cable and year of installation, both of which are substantial indicators of pending failure.

Those of highest priority are subsequently channeled into a capital replacement program with expenditures for installing new cable; expenditures will also include the installation of duct banks for housing new cable to aid in future maintenance.

While Bluewater proactively replaces underground cable, it also recognizes that cable may fail in the interim and, as such, also has a reactive maintenance program. For those cables that have failed, Bluewater splices the failed segment responsible for causing an interruption to service. The reactive approach is continued for subsequent failures, up to a maximum of approximately two to three failures, after which that section of cable is moved up in priority and is scheduled for replacement under the capital replacement program noted above.

Pad Mounted Transformers

Inspection and Condition Assessments

A visual inspection is completed once every 7 years.

Maintenance and Sustainment

Preventive maintenance of residential subdivision distribution pad-mount transformers is performed on an approximate seven year cycle. The program, which entails inspection and maintenance activities, is initiated through the issuance of a work order, map of the subdivision subject to maintenance and identification of transformers and the individual attributes of each by the Manager Technical Resources.

Also issued is a scope of work, developed internally and based on consultation with neighbouring utilities, utility best practice and experience. The scope of work provides specific instructions for inspection and maintenance that are performed concurrently.

Each transformer is removed from service and opened to verify nameplate data and attributes. Subsequently, the Journeymen Linemen execute each of the items within the scope of work. Where a discrepancy exists between field data and information provided, the inspector documents data/attributes as existing in the field to ensure accuracy of records.

Inspection of switching cubicles is also included in subdivision maintenance and thereby performed on an approximate seven-year cyclical basis. Inspection comprises of both internal and external assessment of switching cubicle components, such as insulators, arc suppressors, cable terminations, door hinges, and fault indicators. The switching cable is also inspected for evidence of excess moisture, overheating, arcing, degradation of paint, corrosion, and improper placement on the pad.

Assets are repaired or replacement based on the risk rating determined by the Asset Inspector. Immediate repair or replacement of assets is completed if damage or deficiencies are noted during the inspection or patrol, such as oil leaks, excessive rusting, physical damage, overheating, or noise.

Pad Mounted Switches

Inspection and Condition Assessments

A visual inspection is completed once every 7 years.

Maintenance and Sustainment

Dry ice cleaning is completed as needed in select locations.

Planned repair or replacement is completed based on the risk rating determined by the Asset Inspector. Immediate repair or replacement is completed if damage or deficiencies are noted during inspection or patrol (excessive rusting, physical damage, overheating, etc.).

MUNICIPAL SUBSTATIONS

Bluewater's municipal substations operate at a primary voltage of 27.6 kV with secondary transformation to 8.32 kV or 4.16 kV, supplying main feeders for wide-area distribution to residential and commercial customers.

Inspection and Condition Assessments

Control Room Operators inspect Bluewater's municipal substations at least once every month and may be inspected more frequently when time permits. To facilitate inspection and documentation, an assessment reporting form is used, providing an itemized list of substation components to be assessed. Deficiencies observed are documented; comments may also be included, elaborating on the nature of the deficiency. Following inspection, the completed assessment reporting form is reviewed by the Manager Technical Resources.

Maintenance and Sustainment

Bluewater's maintenance practices for substations include predictive, preventive, and conditioned-base maintenance.

Predictive maintenance in the form of infrared thermography is performed on an annual basis by a contracted party with qualifications in this imaging technique. The inspection is completed concurrently with imaging of the overhead system. The thorough inspection includes imaging of overhead conductors, switches and protective devices, terminations, transformers and bushings, and connectors. Deficiencies (hot spots) and images of the deficiencies are included in the infrared imaging contractor's report. Substations of concern are categorized and prioritized by fault severity. The imaging report is reviewed, and a work order is prepared for condition-based maintenance to remediate identified deficiencies.

Preventive maintenance is performed on a four-year cycle, such that approximately one-quarter of the distribution stations are maintained annually. Preventative maintenance may also be performed during capital improvement projects, for example upgrades to a station. The preventative maintenance program is performed by a contractor and is comprised of inspection, testing, and condition-based maintenance. The scope of work and instructions are based on InterNational Electrical Testing Association (NETA) standards. Items are categorized based on high, medium, and low priority, allowing for the prioritization of deficiencies and remediation response times.

Condition-based maintenance is performed as a result of the monthly inspection and condition assessment or as identified within the predictive and preventative maintenance programs. Identified deficiencies are reviewed and evaluated. Generally, condition-based maintenance to address high priority deficiencies is performed during the inspection and condition assessment of distribution stations. The response time and nature of condition-based maintenance to address medium or low priority deficiencies varies. Medium priority deficiencies are addressed following remediation of high priority deficiencies. If the deficiency may be resolved through a planned capital project, Bluewater will channel remediation into the capital project and continue to monitor the deficiency to ensure no subsequent degradation or failure. Low priority deficiencies, aesthetic in nature, are generally monitored until becoming a medium or high priority.

Condition-based maintenance to remediate deficiencies identified during the thermographic infrared inspection (predictive maintenance) is performed following the preparation and issuance of work orders. Remediation is prioritized based on the assigned priority level in the thermography report.

Condition-based maintenance to remediate deficiencies identified during preventive maintenance are generally remediated at such time, to capitalize on the existing station outage. Maintenance that cannot be performed during preventive maintenance is subsequently performed as materials are available.

Meters, Fleet, Site, IT

Meters

Inspection and Condition Assessments

Visual inspections are completed during disconnect /reconnect, troubleshooting, or other work nearby. Testing and compliance sampling is completed as per Measurement Canada requirements.

Maintenance and Sustainment

Meters are kept in service until failure of unit or the results of a sample test of a batch requires replacement of the batch.

Fleet

Bluewater performs regular inspection and maintenance on all fleet assets. The level of detail and frequency is determined by asset category, regulatory requirement, and condition. Further details may be found at Fleet Management Plan (Appendix E).

A history of the condition, maintenance, inspections, required repairs, and annual costs are documented and recorded in its Collective Data Fleet software program. Bluewater annually reviews costs and condition of all units as a part of its recommendations for vehicle upgrades and replacement.

Other factors such as age, mileage, engine hours, PTO ("Power Take Off") hours, appearance, and frequency of use are all contributors to the decision-making process to upgrade or replace an asset.

Light Duty Fleet

Inspection and Condition Assessments

Visual inspections are completed monthly. The manufacturer's recommended schedule is followed.

Maintenance and Sustainment

Vehicles are repaired and maintained until cost, reliability, and/or functionality become an issue.

Heavy Duty Fleet

Inspection and Condition Assessments

Visual inspections are completed daily. Yearly CVOR safety inspections are required. Utility vehicles, including bucket trucks and Radial Boom Derricks ("RBDs"), require quarterly preventative maintenance inspection, as well as yearly di-electric testing.

Maintenance and Sustainment

Maintenance is completed in accordance with the manufacturer's recommended schedule. Additional testing is completed every year for dielectric components.

Vehicles are repaired and maintained until cost, reliability, and/or functionality become an issue.

Safety inspection and preventative maintenance inspection results are used to gauge replacement timing.

Site

Inspection and Condition Assessments

Visual inspection of the facility is completed once every month to check for safety hazards. Detailed inspection of the HVAC units is completed quarterly, and inspection of the roof is to be completed annually.

Maintenance and Sustainment

Minor repairs and simple maintenance (painting, re-caulking, etc.) are completed as needed.

HVAC units are repaired as needed and replaced when they require extensive repair or repair is recommended by inspector. Other components (such as windows, lighting) rea replaced if more energy efficient options are available; this requires a business case. Furniture, equipment, carpeting, and so on is replaced when it is worn out.

IT

Bluewater retains a number of diverse technology assets used to perform business functions and serve customer needs. These assets include both hardware and software and extend to Information Technology (IT) and Operations Technology (OT) services. Implementation of these assets follow the four primary guiding principles described elsewhere in this document and include the following:

1. Advancing Customer and Business Functions
2. Ensuring Continuity of Technology Platforms
3. Responding to Regulatory Requirements
4. Providing Mitigating Solutions to Guard Against Cyber Security Threats

All assets are catalogued in an asset management solution and are maintained through various warrantees, lifecycles, active monitoring, and change management practices. These can be broken down into the following groupings.

Hardware:

Datacenters, networking, cabling, compute, storage, security, HVAC, electrical, UPS, Fire suppression, monitoring tools, Wi-Fi, desktop computers, laptops, printers, copiers, fax machines, mailing equipment, audio visual devices, video conference solutions, phones, mobile devices, radio communication devices, fleet GPS devices, remote communication devices.

Software:
Operating systems, virtualization, databases, backup and restoration, desktop office suite, email solution, website hosting, social media platforms, call centre management software, voicemail, end-point security, ERP, GIS, Locate management, Engineering tools, SCADA, Outage Management, Smart Meter management, MDM/R interface tools, Fleet Management, meter reading software, Remote Access, Project management tools.

5.3.3.3 Asset Life Cycle Risk Management and Prioritization

Bluewater manages asset risk in two phases – during inspection and maintenance activities by staff, and through the ACA conducted by a third party. While conducting planned inspections or maintenance, or during an unplanned inspection (such as a line patrol to search for an outage cause), Bluewater staff identify assets that are at risk of imminent failure and will make arrangements for immediate repair or replacement. If the failure risk is not imminent, the results of the inspection or maintenance activity are sent to the ACA third party who utilizes the observations and test results to generate a health index and risk assessment which lead to a listing of assets flagged for action.

The methodology used by the third party to generate the flagged for action list for each class of asset is outlined in Appendix A.

The ACA is provided to Bluewater each year, based on the previous years' data. The flagged-for-action list is then reviewed by Bluewater staff to select projects for the next year's budget as well as adjust the five year projections. Staff consider other factors such as obsolescence, municipal plans, system expansions and enhancements, regulatory requirements, and customer preferences when finalizing the budget. Section 5.4.1 Capital Expenditure Summary outlines the process used to create the annual capital budget including prioritization of projects.

5.3.4 System Capability Assessment for Renewable Energy Generation

5.3.4.1 Applications over 10 kW

As of the end of 2021 Bluewater connected 11 RESOP projects, 10 Feed-In-Tariff (FIT) projects, 197 microFIT projects plus 11 net metering projects, 3 Combined Heat and Power (CHP), and 1 Battery Energy Storage Systems (BESS) with a total of 92,944.78 kW of renewable generation.

Table 31: Summary of Generation Connections

	Number of Sites	Installed Capacity (kW)
RESOP	11	84,010.0
FIT	10	2,158.0
microFIT	196	1,736.17
Net Metering	11	105.84
CHP	3	1,361.00
BESS	1	3,500
Total	**233**	**92,994.78**

5.3.4.2 REG Forecast

At the end of 2017, the IESO ceased accepting applications for the microFIT program having reached the 50 MW annual procurement target. Similarly, the FIT program ended in 2016 with no further applications being accepted. Instead of the Feed-in-Tariff program, the Province is encouraging customers to look at other emerging technologies including net metering as an alternative way of reducing their electricity bills. Bluewater currently has 11 net metered customers representing 105.84 kW of installed capacity.

Bluewater supports and encourages the participation in the net metering program; however, the lack of incentives for customers has somewhat stalled the market. Bluewater anticipates only a modest increase in the number of net metered customers over the next five years. Bluewater does not anticipate more than 4 net metering customers to be added per year.

5.3.4.3 Capacity to Connect REG

Bluewater monitors the capacity of all feeders and maintains an inventory of all available capacity. Bluewater’s distribution system has been determined to be adequate to accept renewable generation that is anticipated on all feeders with the exception of the embedded line sections of two Hydro One feeders.

Bluewater coordinates with Hydro One on certain connections. Hydro One provides Bluewater a yearly threshold allocation; if Bluewater requires capacity above the allocation, further requests are made to Hydro One.

The table in the next section provides the available capacity by station. Historically, applications for REG connections have been under 1 MW for the smaller communities, and under 5 MW for Sarnia and Point Edward. For most areas, Bluewater has existing capacity allocated via a threshold allocation, and can apply to HONI for an increase in that allocation if there is a specific project that is considering connected a generator within the Bluewater service area.

5.3.4.4 REG Constraints

The Bluewater system is supplied by three transformer stations (TS) and two distribution stations (DS) owned by Hydro One, as well as various municipal stations (MS) owned by Bluewater. Most of the distribution system is at 27.6 kV with a few areas at 8.32 kV and 4.16 kV. Table 32 summarizes the capacity and constraints (if any) by station, feeder, and supply voltage (as of April 27, 2022).[5]

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[5] Available Thermal and Short Circuit Capacity are based on the Hydro One List of Station Capacity and the published on the Hydro One website.

Table 32: Capacity and Constraints

Station and Bus	Voltage	Available Thermal Capacity	Available Short Circuit Capacity	Allocated (available) to Bluewater[6]	Constraint (if any)
Modeland TS, J Bus Feeders M23, 25, 27, 29, 31	27.6 kV	44.4 MW	81.2 MW	2.7 (1.683) MW	Based on existing Threshold Allocation
Modeland TS, Q Bus Feeders M24, 26, 28, 30	27.6 kV	44.3 MW	82.3 MW	2.5 (1.9) MW	Based on existing Threshold Allocation
St Andrews TS, QZ Bus Feeders M11, 12, 13, 14, 15 ,16	27.6 kV	87.9 MW	76.6 MW	1.0 (0.605) MW	Based on existing Threshold Allocation
Wanstead TS, JQ Bus Feeders M1, M2,M3, M4	27.6 kV	55.5 MW	0.0 MW	0 MW	Restricted by HONI
Sarnia / Point Edward MS – various DS stations owned by Bluewater	4.16 kV or 8.32 kV			1.0 (0.605) MW or 2.7 (1.683) MW or 2.5 (1.9) MW Based on source feeder	Based on existing Threshold Allocation
Watford MS Supplied from Wanstead TS	4.16 kV			0 MW	Restricted by HONI
Alvinston DS, Supplied from Wanstead TS M1	8.32 kV	3.1 MW	n/a	0 MW	Restricted by HONI
Petrolia MS 30, 31, and 32 Supplied form Wanstead TS	4.16 kV			MS30 = 0 kW MS31 = 0 kW MS32 = 0 kW	Restricted by HONI
Oil Springs DS, F1 Supplied from Wanstead TS M4	8.32 kV	2.4 MW	n/a	0 kW	Restricted by HONI

Bluewater is currently positioned to allow additional generation on all of its feeders fed out of the Modeland Rd and St. Andrews TS. Bluewater is not able to allow additional generation on feeders fed out of the Wanstead TS.

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[6] Allocations are based on existing Threshold Allocations, which could be increased if a specific request is made by Bluewater on behalf of a proposed generation connection.

Bluewater's Analysis Methods for Interconnection of Distributed Generators

1. Distribution Connected Feeders (embedded feeders within Hydro One's distribution system): Wanstead TS– 41M1, 41M2, 41M3, 41M4, 1832F1, 2952F2

   >10 kW – Constrained by Hydro One on September 17, 2019.

   ≤10 kW – Constrained by Hydro One on September 17, 2019.

Bluewater is not able to allow additional generation on these feeders.

2. Transmission Connected Feeders: Modeland TS – 96M23, 96M24, 96M25, 96M26, 96M27, 96M28, 96M29, 96M30, 96M31 and St. Andrew's TS – 18M11, 18M12, 18M13, 18M14, 18M15, 18M16

   >500 kW – Individual CIA required for each application

   >10 kW-≤500 kW – Bluewater currently manages three (3) Threshold Allocations (TA) with Hydro One that can act in place of a CIA for certain applicants. Otherwise, an individual CIA is required for projects that fall outside the TA's project requirements.

   ≤10 kW – No restrictions at this time.

Bluewater is in a position to allow additional generation on these feeders.

5.3.4.5 Embedded Distributor Constraints

There are no embedded distributors within the Bluewater distribution system.

5.3.5 CDM Activities to Address System Needs

As described below, Bluewater continually monitors system capacity, and partakes in initiatives to offset load and defer the need to new infrastructure. Bluewater has also recently completed a system study that confirms new distribution infrastructure is not required in the forecast period. As such, CDM activities through distribution rate funding are not incorporated in the DSP.

In 2009, a Bluewater affiliate installed a 600 kW gas collection and generation system at a closed landfill in its system. The energy generated by this facility was connected to Modeland TS and helped to offset load at that station and consequently increased the capacity at that station.

In 2010, Bluewater worked with First Solar to facilitate the installation and connection of 80 MW of solar generation in its service territory. Generation is divided into blocks of 10 MW with 20 MW connected to St Andrews TS feeders and 60 MW connected to Modeland TS feeders. This generation has helped to offset load on each station and consequently increased capacity at those stations.

Also in 2010, a Bluewater affiliate partnered with Waste Management to install a 2.4 MW gas collection and generation system at a landfill connected to Wanstead TS which feeds Bluewater's service territory. This generation helps to offset load on that station and has consequently increased capacity.

In 2016, Bluewater partnered with RES America to try to develop a battery storage system in its service territory. This project was ultimately not approved by the IESO.

Bluewater recently completed a study to identify areas of its grid that are near capacity, and therefore may need upgrades. The study was limited to the City of Sarnia, with the assumption the same principles could be applied to the other regions of Bluewater's distribution area.

In order to do the study, Bluewater looked at the loads of each phase of the three phases on all 4 Kilovolt circuits in its system for the last two years. Bluewater Power then took the highest value for a single phase and set it as the peak value for that feeder. Bluewater also looked at the peak value for each transformer at its 4 kilovolt substations to check the total of all collective loads of the feeders coming from that station. Bluewater also checked conductor sizes on the circuits to ensure they were not too small and would therefore act as a 'bottle neck' to the flow of current.

For the purposes of this study Bluewater looked primarily at the 4.16 Kilovolt (4 kV) system. This system is its original supply system fed from the 27.6 Kilovolt (27.6 kV) feeder system out of Modeland and St. Andrews transmission stations. Parts of the 4 kV system are getting close to capacity due to being designed and built in a time before the loads of have today such as air conditioning. The table below shows remaining capacity for all transformers and feeders of Bluewater's 4 kV system.

Table 33: Bluewater 4 kV system remaining capacity in percent

Substation	Transformer 1	Transformer 2	Feeder 1	Feeder 2	Feeder 3	Feeder 4	Feeder 5	Feeder 6	Feeder 7	Feeder 8	Feeder 9
1	66.75%	60.58%	48.25%		39.50%				71.00%	52.00%	35.50%
3	26.38%		41.50%	42.75%	41.00%	72.75%					
5	68.14%		46.07%	43.37%							
7	36.11%		30.50%	50.50%	67.00%						
8	33.08%		42.00%	29.50%	92.25%	62.00%	77.75%				
9	57.07%		46.50%	40.25%	75.75%						
10	34.11%		66.75%	67.25%	90.25%	22.50%					
11	21.62%		40.75%	63.75%	37.50%						
12	37.19%		33.00%	41.75%	55.50%						
13	20.08%		48.75%	13.75%	55.00%						
14	37.55%		48.00%	28.33%							

As Table 33 shows, most of the 4 kV system has enough capacity to allow for additional loading to be added. Bluewater has been steadily working on converting to 27.6 kV over the years and have already been able to eliminate three 4 kV substations (#2, #4 and #6) as well as two 8 kV stations (#20 and #22).

The feeders and transformers that have one-third or less remaining capacity are highlighted in yellow. These are the feeders that would require upgrading in order to allow additional load, such as load for charging electric cars.

Bluewater feels the best approach for this would be to convert sections of these lines to the 27.6 kV system. This does not add load to the 27.6 kV system since the 4 kV substations are already fed from those lines. However, it would free up capacity on the 4 kV lines, allowing for more load.

The 27.6 kV system has the capacity for more load. Bluewater recently participated in a load forecasting exercise where there was the opportunity to project Bluewater's anticipated load growth on the Modeland, St. Andrews and Wanstead transmission stations. Bluewater was aggressive with its forecast, citing a growth of 50% load due both to increased number of residential customers and the addition of car chargers throughout Bluewater's area. Hydro One accepted Bluewater's forecast with no concern about adding these loads to the existing station load.

In order to get a rough idea of costs, Bluewater assumed an average peak load of 5 kilowatts per household. Bluewater also estimated a cost of $20,000 for a new 27.6 kV transformer installation, which would feed roughly 20 customers. Bluewater also assumed there is a 27.6 kV circuit already on the pole the transformer would be installed on and that no further infrastructure would be required. Looking at

Table 32, Bluewater can see there are 10 circuits or transformers which are within 30% of available capacity. Bluewater feels it would be able to get to a level of 50% of available capacity on those feeders and transformers, leaving another potential 50% capacity, for a cost of under $750,000, and a project for that value has been added to its 2023 capital budget under project number UT74. As mentioned in the capital project sheet (see Appendix F), Bluewater owns eleven 4 kV municipal substations in Sarnia with air magnetic type circuit breakers. These breakers are aging, and Bluewater has no spare breakers or parts for them. Bluewater is planning to upgrade the 4 kV system by converting some to 27.6 kV and working with the 4 kV system to balance load and re-distribute load amongst all the 4 kV feeders with the goal of having a spare cell and breaker in each station, where possible.

Bluewater has considered the use of distribution rate funded CDM programs to defer distribution infrastructure. However, due to the fact that no new infrastructure is needed to increase capacity, the use of distribution rate-funded CDM programs to defer distribution infrastructure is not being included in the 5-year plan.

5.4 CAPITAL EXPENDITURE PLAN

System Development Expectations

The Bluewater system is expected to continue to provide safe and reliable supply to its customers for the next five years and beyond.

Historically, Bluewater has seen slow growth rates for customers paired with declining consumption. Between 2013 and 2021, total number of metered customer accounts grew by 1,039, a compound annual growth rate (“CAGR”) of only 0.36% per year. Within that time period, Bluewater lost 13 General Service <50 kW customers, 56 General Service >50 to 999 kW customers, and 4 General Service 1000 to 4999 kW (“Intermediate”) customers. Consumption (total kWh) between 2013 and 2021 decreased by 4.8% (CAGR -0.61%).

Table 34 through Table 36 show historical actual data and forecast from the Load Forecast Report in Exhibit 3 of Bluewater’s Rebasing Application.

Table 34: Historical and Forecast kWh for 2013 to 2023

Normal Forecast

kWh	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Residential	255,389,582	248,491,220	247,531,815	254,829,615	243,695,248	259,006,064
GS < 50	103,284,259	103,923,431	104,997,600	103,858,081	99,503,004	101,399,120
GS > 50	222,721,188	216,401,666	210,203,757	207,887,227	196,589,569	198,076,032
Intermediate	161,171,663	159,033,210	158,080,305	156,593,665	137,456,443	136,386,985
Large User	251,680,101	255,196,632	255,903,896	281,637,471	289,478,994	287,387,432
Street Light	9,144,166	8,086,583	6,427,057	5,119,606	4,349,789	3,664,818
Sentinel Light	547,347	536,887	507,380	497,069	476,322	453,200
USL	2,183,026	2,203,828	2,211,250	2,221,667	2,156,982	2,052,963
Total	1,006,121,332	993,873,459	985,863,059	1,012,644,400	973,706,352	988,426,613

kWh	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast
Residential	251,122,549	270,338,602	275,475,848	270,291,183	265,592,217
GS < 50	101,723,564	94,820,550	98,943,526	103,387,625	105,317,729
GS > 50	193,322,393	182,593,246	185,117,331	192,603,165	192,112,284
Intermediate	131,667,230	121,864,255	126,088,597	119,342,811	118,382,643
Large User	290,955,053	281,204,845	266,221,942	280,142,331	282,898,876
Street Light	3,457,006	3,449,208	3,351,425	3,356,657	3,361,898
Sentinel Light	474,594	439,110	433,168	423,796	414,626
USL	2,202,857	2,209,114	2,181,431	2,162,262	2,201,349
Total	974,925,246	956,918,930	957,813,268	971,709,830	970,281,623

Table 35: Historical and Forecast kW for 2013 to 2023

Normal Forecast

kW	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
GS > 50	622,926	607,208	582,473	575,501	560,226	559,688
Intermediate	346,643	359,107	346,802	320,386	281,957	279,319
Large User	396,800	404,064	400,651	436,453	479,867	486,459
Street Light	24,351	21,697	17,287	13,686	11,695	10,174
Sentinel Light	1,313	1,278	1,254	1,205	1,324	1,302
Total	1,392,033	1,393,354	1,348,468	1,347,231	1,335,069	1,336,941

kW	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast
GS > 50	528,420	511,401	522,129	540,503	539,125
Intermediate	265,773	241,408	245,050	232,004	230,138
Large User	477,955	461,493	471,315	470,751	475,383
Street Light	9,621	9,569	9,338	9,133	9,147
Sentinel Light	1,299	1,196	1,187	1,175	1,149
Total	1,283,068	1,225,066	1,249,020	1,253,566	1,254,942

Table 36: Historical and Forecast Customer/Connections for 2013-2023

Customers / Connections

kW	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Residential	32,002	32,139	32,277	32,434	32,605	32,755
GS < 50	3,472	3,495	3,497	3,475	3,478	3,468
GS > 50	428	393	377	373	382	389
Intermediate	13	12	12	12	11	11
Large User	3	3	3	3	4	4
Street Light	10,030	10,051	10,013	10,018	10,042	10,068
Sentinel Light	428	418	412	407	391	385
USL	262	262	262	261	258	256
Total	46,636	46,772	46,853	46,984	47,171	47,336

kW	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast
Residential	32,862	32,990	33,113	33,251	33,390
GS < 50	3,485	3,490	3,459	3,489	3,487
GS > 50	372	369	372	360	354
Intermediate	11	10	9	9	8
Large User	4	4	4	4	4
Street Light	10,100	10,136	10,161	10,177	10,193
Sentinel Light	385	371	367	359	351
USL	257	253	243	241	342
Total	47,476	47,623	47,728	47,889	48,128

The Load Forecast predicts that the slow growth rate will continue, with only a 0.77% increase to metered customers between 2021 and 2023 forecasted (0.39% CAGR). Forecasted consumption (kWh) is also predicted to decline between 2021 and 2023 by 0.025% (-0.12% CAGR).

As load growth is forecast to be manageable in the next two years, no new supply points are planned, with a few feeder extensions to service new residential and commercial subdivisions. System Renewal will remain the largest portion of capital spending, as assets are replaced due to condition.

Bluewater does not expect any significant changes in the system over the next five years for climate change adaptation. Bluewater is a member of the collaborative group Utility Standards Forum (“USF”), and Bluewater uses the latest construction designs that meet or exceed the requirements of federal and provincial standards. Bluewater has adopted more stringent design specifications and uses software (SPIDAcalc) to model new pole installations for various weather conditions. Bluewater has not experienced any localized extreme weather that would warrant any additional upgrades to the system.

Investments in new technology to assist with monitoring and managing the distribution system are expected, such as automated / remote controlled switches to improve reliability and operating flexibility. Bluewater has already invested in reclosers on the distribution system, and an outage management system (OMS), with plans to enhance the OMS with an automated Fault Location, Isolation, and Service Restoration (FLISR) system.

All the known restrictions preventing the connection of renewable energy generation projects are within Hydro One’s transmission or distribution system and Bluewater has no plans to invest in system upgrades until these upstream restrictions are addressed.

Strategy for Modernization Opportunities

Through consultations with suppliers and networking with other distributors, Bluewater remains current on trends in grid modernization and considers the ability to integrate new systems a priority when making investments in new technology. For example, the Outage Management System (OMS) was installed in 2018 and leveraged in 2020 to develop a fully automated Fault Location, Isolation, and Service Restoration (“FLISIR”) system, which will improve system reliability.

The Bluewater IT team has developed a customer online portal called MyAccount. This offering is a complete online solution that provisions customers with account management options and electricity consumption tools presented in a powerful, user friendly, mobile optimized interface. MyAccount provides customers with the opportunity to review and download customer bills and consumption data. It also allows customers to see the amount of electricity they consumed up to midnight the day before and historically for up to two years. Using this tool, customers are able to add change events in a timeline of consumption to help them see before and after usage patterns. For example they can see their consumption before installing a hot tub and after, or when their children are away at school versus when they are living at home. This gives them useful information to better help them understand the impacts of their consumption choices.

Another customer assistance tool that is in development at Bluewater is Green Button. Green Button is a North American Energy Standards Board standard whereby utilities provide customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format. In Ontario, the regulation requires utilities to develop or procure a software solution to implement Green Button in accordance with the NAESB ESPI standard rules and provide energy data to authorized third party services, on the consent of the consumer and in accordance with the standard. The implementation of Green Button will go live in November of 2023. Bluewater will be implementing a hybrid approach consisting of internal and third-party costs.

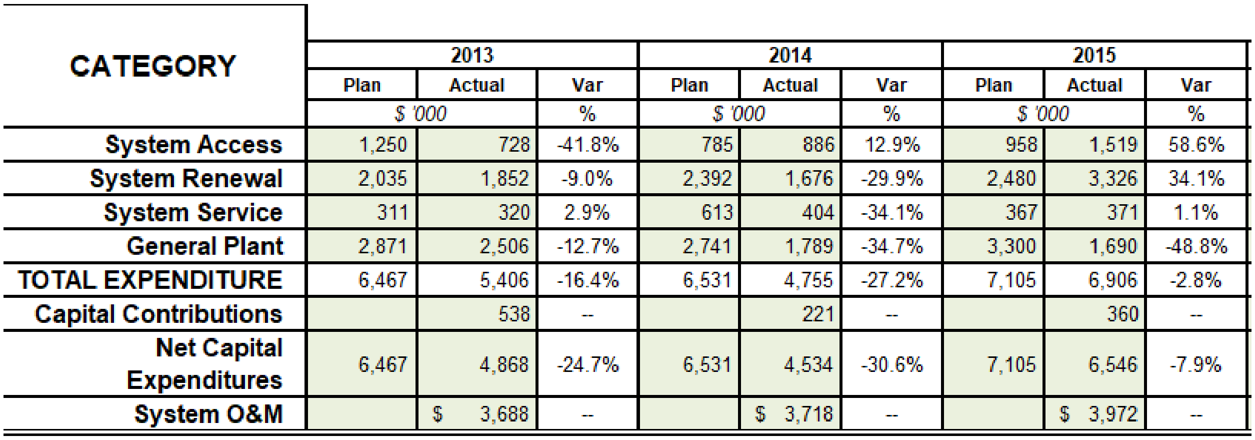
5.4.1 Capital Expenditure Summary

This section provides a review of Bluewater's capital expenditures for its historical years (since last Rebasing in 2013) and five forecast years from 2023 to 2027. Because this is Bluewater's first DSP, this section discusses Bluewater's internal capital budget versus actual expenditure amounts for each historical year. Explanations for variances in each investment category that are trending higher or lower over the historical period are provided.

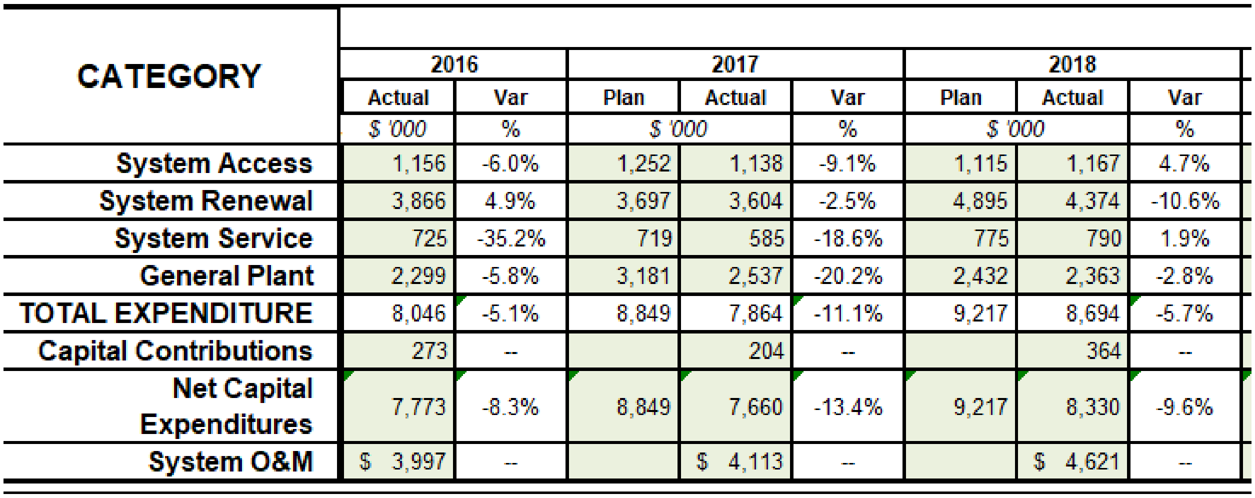
Bluewater follows the capitalization practices described in the OEB Accounting Procedures Handbook (APH). For projects that have a life cycle greater than one year, or that cross the fiscal year end, some or all of the capital expenditures may be treated as Construction Work in Progress (CWIP). The CWIP related costs would then be carried forward to a subsequent year until the electric assets are put into service. The OEB's APH makes some exceptions for the accounting treatment of major spare parts and standby equipment such as transformers and meters.

The following Table 37 provides a snapshot of Bluewater's capital expenditures over a 10-year period. Chapter 2 Appendix 2-AB is also filed as part of Bluewater's rate application in live Excel format. Table 44 displays those investments in a bar graph as a percentage each year. Table 38 shows Bluewater's capital project investments during the historical period, organized by investment category.

Table 37: Appendix 2-AB Capital Expenditure Summary



CATEGORY	2013			2014			2015		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	1,250	728	-41.8%	785	886	12.9%	958	1,519	58.6%
System Renewal	2,035	1,852	-9.0%	2,392	1,676	-29.9%	2,480	3,326	34.1%
System Service	311	320	2.9%	613	404	-34.1%	367	371	1.1%
General Plant	2,871	2,506	-12.7%	2,741	1,789	-34.7%	3,300	1,690	-48.8%
TOTAL EXPENDITURE	6,467	5,406	-16.4%	6,531	4,755	-27.2%	7,105	6,906	-2.8%
Capital Contributions		538	--		221	--		360	--
Net Capital Expenditures	6,467	4,868	-24.7%	6,531	4,534	-30.6%	7,105	6,546	-7.9%
System O&M		$ 3,688	--		$ 3,718	--		$ 3,972	--



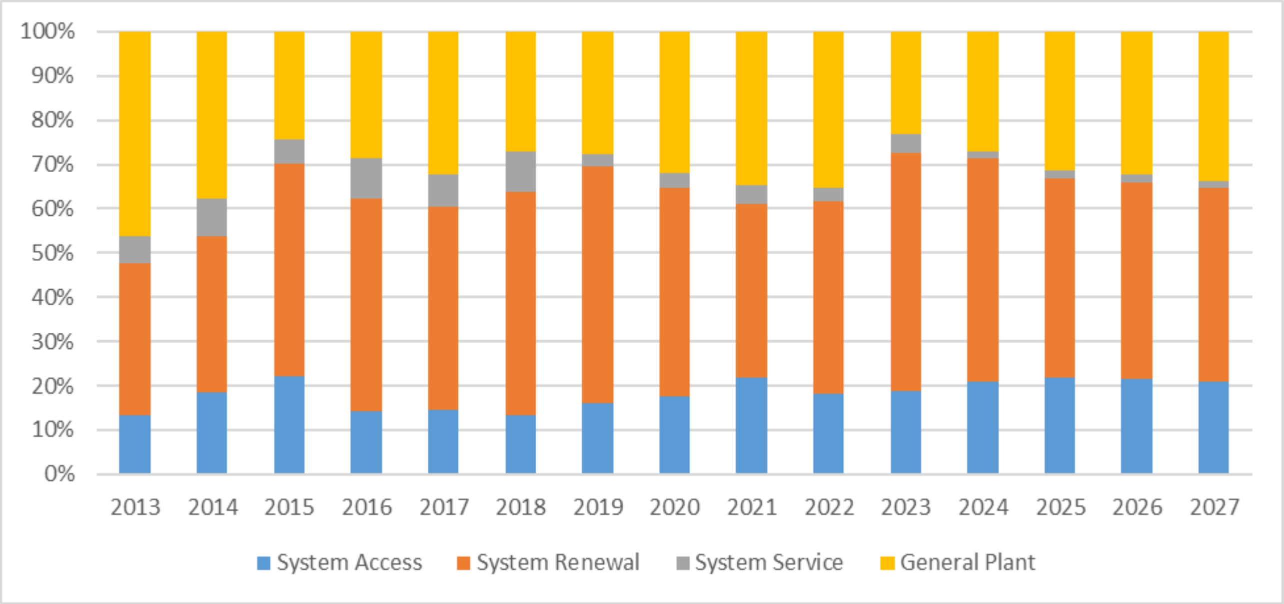
CATEGORY	2016		2017			2018		
	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000	%	$ '000		%	$ '000		%
System Access	1,156	-6.0%	1,252	1,138	-9.1%	1,115	1,167	4.7%
System Renewal	3,866	4.9%	3,697	3,604	-2.5%	4,895	4,374	-10.6%
System Service	725	-35.2%	719	585	-18.6%	775	790	1.9%
General Plant	2,299	-5.8%	3,181	2,537	-20.2%	2,432	2,363	-2.8%
TOTAL EXPENDITURE	8,046	-5.1%	8,849	7,864	-11.1%	9,217	8,694	-5.7%
Capital Contributions	273	--		204	--		364	--
Net Capital Expenditures	7,773	-8.3%	8,849	7,660	-13.4%	9,217	8,330	-9.6%
System O&M	$ 3,997	--		$ 4,113	--		$ 4,621	--

Table 37: Appendix 2-AB Capital Expenditure Summary (continued)

CATEGORY	Historical Period (previous plan[1] & actual)								
	2019			2020			2021		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	1,200	1,530	27.5%	1,050	1,694	61.3%	1,400	1,964	40.3%
System Renewal	5,340	5,103	-4.4%	5,290	4,506	-14.8%	5,370	3,541	-34.1%
System Service	260	246	-5.4%	350	301	-14.0%	410	366	-10.7%
General Plant	3,099	2,636	-14.9%	3,292	3,062	-7.0%	3,660	3,136	-14.3%
TOTAL EXPENDITURE	9,899	9,515	-3.9%	9,982	9,563	-4.2%	10,840	9,007	-16.9%
Capital Contributions		331	--		482	--		229	--
Net Capital Expenditures	9,899	9,184	-7.2%	9,982	9,081	-9.0%	10,840	8,778	-19.0%
System O&M		$ 4,152	--		$ 4,137	--		$ 4,603	--

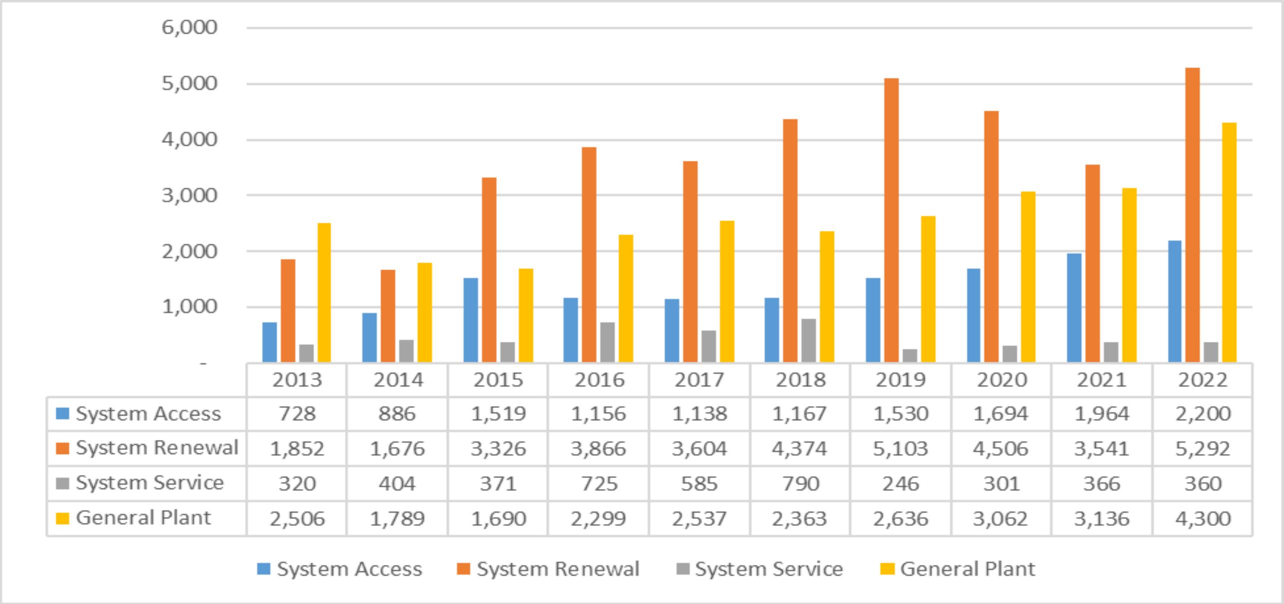
CATEGORY	Historical Period (previous plan[1] & actual)			Forecast Period (planned)				
	2022			2023	2024	2025	2026	2027
	Plan	Actual[2]	Var					
	$ '000		%	$ '000				
System Access	2,200	2,200	0.0%	2,322	2,446	2,520	2,595	2,642
System Renewal	5,292	5,292	0.0%	6,659	5,900	5,244	5,401	5,520
System Service	360	360	0.0%	514	194	200	206	211
General Plant	4,300	4,300	0.0%	2,877	3,170	3,630	3,903	4,257
TOTAL EXPENDITURE	12,152	12,152	0.0%	12,372	11,710	11,594	12,105	12,630
Capital Contributions	1,000	1,000	0.0%	1,000	1,000	1,000	1,000	1,000
Net Capital Expenditures	11,152	11,152	0.0%	11,372	10,710	10,594	11,105	11,630
System O&M	$ 5,774	$ 5,774	0.0%	$ 6,490	$ 6,685	$ 6,886	$ 7,092	$ 7,305

Figure 44: Historical Actual and Forecast Planned Capital Expenditures by Category



**2022 Budget*

Figure 45: Comparative expenditures by category over the historical period ($‘000)



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Access	728	886	1,519	1,156	1,138	1,167	1,530	1,694	1,964	2,200
System Renewal	1,852	1,676	3,326	3,866	3,604	4,374	5,103	4,506	3,541	5,292
System Service	320	404	371	725	585	790	246	301	366	360
General Plant	2,506	1,789	1,690	2,299	2,537	2,363	2,636	3,062	3,136	4,300

**2022 Budget*

Table 38: Appendix 2-AA Capital Projects Table 2013-2021 (Actuals)

	Projects	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022 Bridge Year	2023 Test Year
	System Access											
UT11	New Connections, Upgrades, Subdivisions	623,702	856,829	900,248	1,028,174	776,707	924,273	1,264,310	1,246,001	1,832,038	2,000,000	2,110,000
M1	Single Phase Meters and Poly Phase Meters	85,181	21,161	35,399	73,671	115,638	73,241	5,751	395,981	94,381	100,000	104,500
M5	GS > 50 KW	-	-	-	-	136,794	150,518	206,387	-	-	-	-
M7	Smart Meter Replacement ESA	-	-	553,048	27,010	-	-	-	-	-	-	-
	Miscellaneous (projects under materiality)	19,154	7,922	30,636	27,103	109,188	19,456	53,055	52,228	**37,902**	**100,000**	**107,500**
	Sub-Total	**728,037**	**885,912**	**1,519,331**	**1,155,958**	**1,138,327**	**1,167,488**	**1,529,503**	**1,694,210**	**1,964,320**	**2,200,000**	**2,322,000**
	System Renewal											
UT4	27.6kV Neutral Program	1,992	43,365	139,692	64,529	-	-	-	-	-	-	-
UT5	Petrolia	24,165	64,616	55,512	138,588	41,355	38,972	338,871	5,661	156,686	100,000	208,000
UT6	Alvinston/Oil Springs Capital Items	11,753	20,977	12,875	12,548	13,224	14,534	104,412	230,902	5,707	100,000	20,600
UT7	4KV Lines Rebuild/ Load Conversion	82,455	3,415	99,242	202,065	41,919	26,717	308,320	187,281	4,525	200,000	210,000
UT8	Pt Edward upgrades	22,898	8,535	50,178	39,973	92,942	285,557	30,916	74,228	82,397	50,000	51,300
UT14	Cross Arm/Cap & Pin Insulator Replacement Program	75,063	133,907	182,129	183,116	189,407	114,276	62,235	184,601	155,826	150,000	153,000
UT15	Wood Pole Replacement Program	192,531	180,841	784,501	1,151,248	1,911,268	1,706,437	2,040,526	2,316,330	1,563,010	1,900,000	1,957,000
UT16	Watford	18,611	10,013	51,340	50,508	50,975	7,088	47,904	37,891	62,943	100,000	208,000
UT18	Unforeseen Capital Fund	185,397	350,106	120,328	226,522	180,328	262,327	190,325	85,072	140,876	200,000	175,000
UT22	8 kv Load Conversion	69,534	40,387	298,385	163,364	129,147	-	256,060	-	-	-	372,500
UT24	Storm Restoration	275,998	200,803	163,721	209,932	256,390	212,537	311,998	235,969	568,753	350,000	385,000
UT26	Primary Underground Cable Replacements	320,683	179,593	229,916	183,671	172,484	539,468	136,001	164,590	42,321	300,000	322,000
UT31	Pad Mount Transformer Replacements	58,475	52,777	64,390	85,891	45,143	74,475	21,224	38,433	11,672	192,000	82,500
UT34	27.6kV Lines Upgrades	9,084	134,870	72,815	357,686	109,055	13,211	10,085	-	29,326	-	-
UT35	Substation Transformer Replacements	126,737	-	-	-	-	-	-	-	153,980	-	-
UT36	Downtown Secondary Network Cable Replacement	-	-	-	-	-	-	115,921	498,990	129,017	350,000	-
UT37	Pole Line Scott Rd./Tashmoo Ave	-	-	196,022	74,145	-	-	-	-	-	-	-
UT47	Emergency Transformer Replacement	-	-	236,735	308,029	297,897	217,559	230,866	253,558	243,557	250,000	262,500
UT48	Emergency Primary Line Replacement	-	-	85,771	49,353	22,321	190,910	57,874	95,998	92,895	80,000	83,500
UT52	Delta/Wye Services	-	-	-	-	-	-	153,904	-	-	-	-
UT53	1F8 Lead Cable Elimination	-	-	-	-	-	-	429,400	2,146	6,531	-	-
UT59	Front St. Pole Line Re-build	-	-	-	-	-	175,173	-	-	-	-	-
UT60	Vault 'K' on George St. - Concrete Lid/Panel Replacement	-	-	-	-	-	9,128	160,118	-	-	-	-
UT63	Indian Rd. S. to Plank Rd. - Pole Line Rebuild	-	-	-	-	-	315,775	- 1,139	-	-	-	-
UT71	PCB Tx Replacement	-	-	-	-	-	-	-	-	27,793	150,000	157,500
UT72	St. Clair Parkway in Sarnia (North of LaSalle Line)	-	-	-	-	-	-	-	-	-	-	262,500
UT73	Albany Substation breaker upgrade	-	-	-	-	-	-	-	-	-	-	210,000
UT74	4kV System Upgrades	-	-	-	-	-	-	-	-	-	-	817,500
UT75	Progress Drive Substation Upgrade	-	-	-	-	-	-	-	-	-	300,000	-
UT76	Downtown Switch Replacement	-	-	-	-	-	-	-	-	-	75,000	131,300
UT21	27.6 Kv Feeder Extensions	207,122	5,525	371,343	284,250	10,358	-	1,905	-	-	250,000	372,500
	Miscellaneous	169,730	246,300	110,784	80,871	39,559	169,400	95,205	94,719	62,799	195,000	217,000
	Sub-Total	**1,852,228**	**1,676,031**	**3,325,679**	**3,866,289**	**3,603,772**	**4,373,544**	**5,102,931**	**4,506,369**	**3,540,615**	**5,292,000**	**6,659,200**
	System Service											
UT25	Remote Load Break Switches	86,732	6,079	130,504	110,405	76,595	82,948	82,205	61,661	111,160	90,000	96,500
UT28	Asset Condition Assessment (feeder & substn)	78,184	185,330	138,355	155,300	158,865	142,095	149,720	137,223	150,245	150,000	-
UT67	Petrolia Wanstead TS	-	-	35,000	350,000	350,000	455,000	-	-	-	-	-
-	Telecommunications - Operations	-	-	-	-	-	-	-	-	-	-	375,000
	Miscellaneous	154,657	212,378	67,433	108,916	-	109,541	14,406	102,009	104,518	120,000	42,900
	Sub-Total	**319,573**	**403,787**	**371,292**	**724,621**	**585,460**	**789,584**	**246,331**	**300,893**	**365,924**	**360,000**	**514,400**
	General Plant											
UT1	Substation Building	27,595	28,503	22,606	51,956	165,347	92,891	31,240	4,850	16,850	75,000	82,500
UT10	Vehicle Replacement	430,500	63,300	77,430	491,583	1,080,380	551,622	281,054	996,818	514,836	730,000	270,000
UT12	Transformers	80,166	80,004	55,622	18,513	141,354	36,822	247,427	63,918	207,064	150,000	165,000
UT19	Service Centre	465,404	89,295	47,284	61,861	80,100	87,198	193,164	187,543	659,469	200,000	150,000
UT39	Operations Technology Systems Workflow	2,001	90,919	137,541	-	-	-	-	-	-	-	-
UT68	Substation #1 Restoration	-	-	303,486	13,050	438	-	-	-	-	-	-
UT70	Decommission Municipal Substation #20	-	-	-	-	-	-	-	-	85,689	150,000	-
IT1	Data Centre Lifecycle	409,122	268,065	95,160	109,888	78,026	108,752	306,220	569,290	396,339	290,000	185,000
IT2	Computer Infrastructure Lifecycle	110,457	109,281	130,974	117,126	153,966	210,443	270,811	211,994	175,649	200,000	200,000
IT3	Corporate IT Security	19,408	71,983	15,267	141,100	86,285	137,943	344,624	203,877	160,318	240,000	220,000
IT4	Internal Technology Development	195,053	338,697	287,977	259,303	313,973	346,005	311,763	344,802	372,210	390,000	425,000
IT5	Legislated Business Application Upgrades	189,750	6,278	157,017	223,654	119,285	132,652	137,043	118,684	80,365	250,000	300,000
IT6	Software-Upgrades and Additions	220,044	65,738	28,136	275,625	54,689	36,267	111,224	136,359	210,174	110,000	110,000
IT8	SCADA / ODS / OMS / GIS	111,428	120,119	264,125	205,618	61,993	-	-	-	-	-	-
IT9	Disaster Recovery Plan Upgrade Phase I,II,I	42,290	215,543	12,275	105,511	7,302	33,488	58,430	37,058	35,716	150,000	158,000
IT33	Utilismart RSVA Utility Data Hub (ODS)	-	-	-	-	-	-	125,035	43,823	13,430	-	-
IT34	Sub 1 Datacentre Expansion	-	-	-	-	-	465,234	-	-	-	-	-
IT35	Business Technology Improvements	-	-	-	-	-	-	-	-	-	280,000	435,000
	Vacant Land	-	-	-	-	-	-	-	-	-	900,000	-
O6	CN Land Rights		160,000									
	Miscellaneous	202,410	81,366	55,112	224,328	193,617	123,382	218,020	142,730	208,272	185,000	176,000
	Sub-Total	**2,505,628**	**1,789,091**	**1,690,011**	**2,299,116**	**2,536,755**	**2,362,699**	**2,636,055**	**3,061,746**	**3,136,381**	**4,300,000**	**2,876,500**
	Total	**5,405,466**	**4,754,822**	**6,906,313**	**8,045,984**	**7,864,314**	**8,693,315**	**9,514,820**	**9,563,218**	**9,007,240**	**12,152,000**	**12,372,100**
	Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***											
	Total	**5,405,466**	**4,754,822**	**6,906,313**	**8,045,984**	**7,864,314**	**8,693,315**	**9,514,820**	**9,563,218**	**9,007,240**	**12,152,000**	**12,372,100**

System Access

System Access investments have historically comprised between 13% and 22% of the overall capital budget and are budgeted to remain in those ranges in the forecast period. The Bluewater service area is not in a high growth area, and this overall trend is expected to continue into the future.

In 2015 and 2016, there was an increase in System Access spending as a result of Smart Meter replacements totalling over $580,00 over the two years.

As noted previously, in recent years, there has been a change in the nature of subdivision development whereby developers are requesting entire subdivisions be developed at a time. There has been a notable increase in the number of lots for subdivisions in 2022 and requested for 2023. The Test Year budget of $2,110,000 for New Connections, Upgrades, Subdivisions (UT11) was developed based on known subdivision developments in anticipation of future new residential connections, commercial projects, which fall under the category of upgrade or new connection, plus historical averages for new residential connections. In 2023, the forecast UT11 budget includes 10% for new residential connections and the remaining 90% is for commercial upgrades, commercial connections, and subdivision development work.

System Renewal

Spending on System Renewal increased in 2015, which reflects an increased emphasis on replacing deteriorated assets in accordance with Bluewater’s Asset Management Process. In particular, a main driver of System Renewal spending has been the replacement of deteriorating wood poles.

Since 2014, Bluewater has retained Kinectrics to conduct an annual Asset Condition Assessment on the condition of its system assets. The Kinectrics report provides a “Flagged for Action” list of prioritized areas with wood poles consistently cited as an area of concern. Wood pole testing is done on the suspect population, and each year the quantity of poles that require replacement increases as the pole population deteriorates. The increased pole testing commencing in 2014 necessitated an increase to pole replacement spending in 2015 and subsequent years. The Wood Pole Replacement budget comprises approximately 36% of the total System Renewal budget between 2023-2027.

In the 2023 Test Year, another driver for System Renewal spending is the completion of the 27.6 kV Feeder Extensions (UT21) and 8 kV Load Conversion (UT22) projects for a total of $745,000, as well as the 4 kV System Upgrade (UT74) project at $817,500 (see Appendix F).

System Service

Investments in System Service have varied in the past, and are expected to level out in the coming years. Most of these projects relate to investments that make minor improvements to system reliability by extending feeders to improve operating flexibility, adding animal protection to prevent outages, and various smart grid investments, such as FLISR. Bluewater has made an effort to pace these investments at a rate that maintains overall system reliability with incremental advances in technology, which is reflective of the preferences that customers have provided to us in various engagements. Overall spending in this category has been between $255,000 and $790,000 per year, and represents between 2.7% to 9.1% of the annual capital budget. For the coming five years, this amount decreases to $120,000 which is 1% of the annual capital budget.

General Plant

It is common for spending on general plant assets to vary somewhat from year to year due to the nature of these assets, which are typically small in quantity but high in replacement cost. Capital Contributions to Hydro One, fleet vehicles, building renovations, and information system updates are examples of these types of assets. Over the past five years, Bluewater has seen some of these investment swings due to the timing of replacements overlapping, in spite of efforts to smooth spending.

In 2017, spending was $2.5 M (32% of total) but this increased to $3.1 M in 2021 (34% of total), primarily due to investments in fleet and facilities (datacentre). In the coming five years, spending in this category is expected to remain around the $3.0 M level (34% of total) due to the on-going need to update and replace these assets.

5.4.1.1 Historical Variances

The following section outlines variances by category, including actuals versus the OEB-approved amounts for Bluewater’s last OEB-approved Cost of Service (2013).

2013 OEB Approved vs. 2013 Actual

2013 System Access: variance -$522,000; -41.8%

Table 39: 2013 System Access Expenditures ($'000)

Project ID	Project	2013 OEB Approved	2013 Actual	Variance
UT11	New Connections, Upgrades, Subdivisions	1,100	624	(476)
	Miscellaneous (3 projects, each with variances less than the materiality threshold)	150	104	(46)
	Total	**1,250**	**728**	**(522)**

In 2013, $1,250,000 was approved in the System Access category, and actual expenditures totalled $728,037. The variance was -$521,963.

New Connections, Upgrades, Subdivisions

New Connections, Upgrades, Subdivisions is budgeted based on known developments and consideration of recent trends, but the actual costs are driven by demand that is beyond the control of the utility. Demand-driven customer projects, including new subdivisions and commercial connections, did not proceed as planned in 2013, resulting in lower System Access expenditures than budgeted in New Connections, Upgrades, Subdivisions. Of significance, the construction of the Blackwell Creek Subdivision with 78 planned lots was deferred.

2013 System Renewal: variance -$183,000; -9.0%

In 2013, $2,035,000 was budgeted in the System Renewal category, and actual expenditures totalled $1,852,288. The variance was -$182,772. The budget versus actual variance of -9.0% in System Renewal expenditures was under 10% and not material.

2013 System Service: variance $8,573; 2.8%

In 2013, $311,000 was budgeted in the System Service category, and actual expenditures totalled $319,573. The variance was $8,573. The budget versus actual variance of 2.8% in System Renewal expenditures was under 10% and not material.

2013 General Plant: variance -$365,000; -12.7%

Table 40: 2013 General Plant Expenditures ($'000)

Project ID	Project	2013 OEB Approved	2013 Actual	Variance
UT19	Service Centre	160	465	305
IT9	Disaster Recovery Plan Upgrade Phase I, II, III	174	42	(132)
O6	CN Land Rights	257	0	(257)
	Miscellaneous (24 projects, each with variances less than the materiality threshold)	2,280	1,999	(281)
	Total	**2,871**	**2,506**	**(365)**

In 2013, $2,870,725 was approved in the General Plant category, and actual expenditures totalled $2,505,628. The variance was -$365,097.

Service Centre

Bluewater's service centre building had roof leaking issues in preceding years. The tar and gravel roof required frequent maintenance and patching. This culminated in the decision to replace the roof with a membrane system, which required the removal of the tar and gravel roof. An architectural firm was hired to oversee the project design and installation. Due to the roof replacement, the amount spent in the Service Centre budget exceeded what was planned. As a result of this installation, maintenance of the roof is no longer frequently required.

Disaster Recovery Plan Upgrade Phase I, II, III

In 2011, Bluewater began a multi-year plan to build a disaster recovery solution. While this was to continue in 2013, it became necessary to invest in a new SAN in the corporate data centre, and budget dollars were shifted to IT1 – Data Centre Lifecycle.

CN Land Rights

In 2013, a budget was approved for a one-time fee paid to CN to eliminate future permitting fees for the crossing or parallel occupancy of CN lands by Bluewater's infrastructure. The agreement with CN was not reached until 2014. Payment of $160,000 was made to CN in 2014.

2013 Total Board Approved Budget vs. 2013 Actual: variance -$1,061,000; -16.4%

Bluewater's 2013 capital expenditures totalled $5,404,466, which was $1,061,259 less than the OEB approved rebasing total of $6,466,725. The difference can largely be attributed to demand-drive customer connection (System Access) projects that did not proceed as anticipated, as well as staff resource issues which resulted in less capital work being completed in 2013. As is seen in subsequent years, the shortfall was more than recovered in future years.

2014 Budget vs. 2014 Actual

2014 System Access: variance $101,000; 12.9%

Table 41: 2014 System Access Expenditures ($'000)

Project ID	Project	2014 Budget	2014 Actual	Variance
UT11	New Connections, Upgrades, Subdivisions	680	857	177
	Miscellaneous (2 projects, each with variances less than the materiality threshold)	105	29	(76)
	Total	**785**	**886**	**101**

In 2014, $785,000 was budgeted in the System Access category, and actual expenditures totalled $885,912. The variance was $100,912.

New Connections, Upgrades, Subdivisions

New Connections, Upgrades, Subdivisions include connection of new customers and upgrades to the system to accommodate customer requests; the budget is set based on known developments and consideration of recent trends. The actual costs are driven by demand that is beyond the control of the utility. There were nine new subdivisions electrically connected in 2014. Typically, an average of four subdivisions were connected each year, and the 2014 budget was based on the 2013 actual connections, as such, the actual expenditures exceeded the budget.

2014 System Renewal: variance -$716,000; -29.9%

Table 42: 2014 System Renewal Expenditures ($'000)

Project ID	Project	2014 Budget	2014 Actual	Variance
UT34	27.6 kV Lines Upgrades	396	135	(261)
UT21	27.6 kV Feeder Extensions	157	6	(151)
	Miscellaneous (18 projects, each with variances less than the materiality threshold)	2,379	1,525	(304)
	Total	**2,932**	**1,676**	**(716)**

In 2014, $2,392,000 was budgeted in the System Renewal category, and actual expenditures totalled $1,676,031. The variance was -$715,969.

27.6 kV Lines Upgrades

The 27.6 kV Lines Upgrades project was completed under budget due to a project re-design from the original plan.

27.6 kV Feeder Extensions

The 27.6 kV Feeder Extensions Project was deferred to 2015 due to staffing issues.

2014 System Service: variance -$209,000; -34.1%

Table 43: 2014 System Service Expenditures ($'000)

Project ID	Project	2014 Budget	2014 Actual	Variance
	Miscellaneous (66 projects, each with variances less than the materiality threshold)	613	404	(209)
	Total	**613**	**404**	**(209)**

In 2014, $613,000 was budgeted in the System Service category, and actual expenditures totalled $403,787. The variance was -$209,213.

2014 General Plant: variance -$1,112,000; -40.6%

Table 44: 2014 General Plant Expenditures ($'000)

Project ID	Project	2014 Budget	2014 Actual	Variance
UT10	Vehicle Replacement	325	63	(262)
UT39	Operations Technology Systems Workflow	250	91	(159)
IT4	Internal Technology Development	154	339	185
IT8	SCADA / ODS / OMS / GIS	284	120	(164)
O6	CN Land Rights	0	160	160
	Miscellaneous (18 projects, each with variances less than the materiality threshold)	1,728	1,016	(712)
	Total	**2,741**	**1,789**	**(952)**

In 2014, $2,740,885 was budgeted in the General Plant category, and actual expenditures totalled $1,789,091. The variance was -$951,794.

Vehicle Replacement

The Vehicle Replacement project was under budget due to the delayed delivery of a large vehicle.

<u>Operations Technology Systems Workflow</u>

The Operations Technology Systems Workflow project, including a mobile workforce technology solution and an inventory management technology solution was planned, but it was decided to not proceed in order to focus on higher priority projects.

<u>Internal Technology Development</u>

The Operations Technology Systems Workflow project, originally included a mobile workforce technology solution and an inventory management technology solution that included changes to SAP. However, a narrower project scope was implemented in order to focus on higher priority projects.

<u>SCADA / ODS / OMS / GIS</u>

The planned Outage Management System project was delayed, because it was decided to obtain a better assessment before moving forward with the project.

2014 Total Budget vs. Actual: variance -$1,936,000; -29.6%

Bluewater's 2014 capital expenditures totalled $4,754,822, which was $1,776,063 less than the budget of $6,530,885. The 2014 expenditures below budget can mainly be attributed General Plant category, including the delayed delivery of a large vehicle.

2015 Budget vs. 2015 Actual

2015 System Access: variance $561,000; 58.6%

<u>Table 45: 2015 System Access Expenditures ($'000)</u>

Project ID	Project	2015 Budget	2015 Actual	Variance
M7	Smart Meter Replacement ESA	0	553	553
	Miscellaneous (3 projects, each with variances less than the materiality threshold)	958	966	8
	Total	**958**	**1,519**	**561**

In 2015, $958,000 was budgeted in the System Access category, and actual expenditures totalled $1,519,331. The variance was $561,331.

Smart Meter Replacement ESA

In January of 2015, The Electrical Safety Authority announced a mandatory recall of all remote-disconnect meters in Ontario. Below are excerpts from their report entitled *Electrical Safety Authority Meter Safety Due Diligence Review Conclusions & Recommendations July, 2015*:

> "On August 6, 2014, the Electrical Safety Authority (ESA) launched a due diligence review of meter safety incidents after reports of meter fire incidents in Saskatchewan. The objective of the review was to determine whether there were potential electrical safety issues for Ontario relating to the events that had occurred in Saskatchewan.
>
> In January, 2015, while the review process was still underway, ESA staff reached the conclusion that there was a meter model in use in Ontario – the Sensus 3.2 with remote disconnect – which shared the same interior component design as the meter used in Saskatchewan. The independent engineer's report in Saskatchewan concluded that design made it susceptible to arcing if water or other contaminants got into the meter and this created a safety risk.
>
> On January 22, 2015, ESA ordered Ontario's Local Distribution Companies (LDCs) to remove from service all Sensus 3.2 with remote disconnect meters. The LDCs completed those removals by May, 2015."

Bluewater had approximately 3,500 of these meters installed. The recall was unexpected, meaning Bluewater had not budgeted for the expense of materials and labour to replace them. As well, the ESA mandated a short timeframe to remove these meters from service so Bluewater had to bring staff in from other utilities and contract agencies to meet the deadlines. As such, Bluewater spent $553,048, which was not budgeted for.

2015 System Renewal: variance $846,000; 34.1%

Table 46: 2015 System Renewal Expenditures ($'000)

Project ID	Project	2015 Budget	2015 Actual	Variance
UT15	Wood Pole Replacement Program	268	785	517
UT22	8 kV Load Conversion	156	298	142
	Miscellaneous (20 projects, each with variances less than the materiality threshold)	2,056	2,243	187
	Total	**2,480**	**3,326**	**846**

In 2015, $2,480,000 was budgeted in the System Renewal category, and actual expenditures totalled $3,325,679. The variance was $845,679.

Wood Pole Replacement Program

In 2014, Bluewater started retaining Kinectrics to complete its Asset Condition Assessment, which flags for action poles that require attention and further inspection.

The Wood Pole Replacement Program was over budget due to increased demand for replacement of critical rotten poles identified by visual inspections.

8 kV Load Conversion

The 8 kV load conversion was over budget, as it was required to reduce load off a deteriorating substation transformer due to its condition. The transformer was not replaced; it was taken out of service in 2021.

2015 System Service: variance $4,000; 1.2%

In 2015, $367,000 was budgeted in the System Service category, and actual expenditures totalled $371,292. The variance was $4,292. The budget versus actual variance of 1.2% in System Service expenditures was under 10% and not material.

2015 General Plant: variance -$1,610,000; -48.8%

Table 47: 2015 General Plant Expenditures ($'000)

Project ID	Project	2015 Budget	2015 Actual	Variance
UT10	Vehicle Replacement	325	77	(248)
UT39	Operations Technology Systems Workflow	345	138	(207)
UT68	Substation #1 Restoration	500	304	(197)
IT1	Data Centre Lifecycle	275	95	(179)
IT3	Corporate IT Security	140	15	(125)
IT4	Internal Technology Development	150	288	138
IT6	Software Upgrades and Additions	185	28	(157)
IT14	Central Filing Document Management	121	1	(120)
IT27	Enterprise Mobility	130	0	(130)
	Miscellaneous (14 projects, each with variances less than the materiality threshold)	1,129	744	(384)
	Total	**3,300**	**1,690**	**(1,610)**

In 2015, $3,299,645 was budgeted in the General Plant category, and actual expenditures totalled $1,690,011. The variance was -$1,609,634.

Vehicle Replacement

A replacement Radial Boom Derrick truck was budgeted for 2015, but manufacturing of the truck was delayed.

Operations Technology Systems Workflow

As in the prior year, the Operations Technology Systems Workflow project, including a mobile workforce technology solution and an inventory management technology solution was planned, but it was decided to not proceed in order to focus on higher priority projects.

Substation #1 Restoration

The 2015 budget for Substation #1 Restoration consisted of an estimate to replace stucco on the building. A less expensive alternative in the form of aluminium siding was identified, and as such, the project came in under budget.

Data Centre Lifecycle

Two projects that included a SAN storage solution and the relocation of the primary data centre UPS were not completed. Upon further assessment of the SAN, it was determined a less costly and viable approach was to add an expansion tray to extend its life. While the location of the UPS system was not optimal, further investigation showed it would not be necessary to relocate it.

Corporate IT Security

A corporate security project to replace corporate firewalls was planned for Q4 and was not fully completed until Q1 2016. As a result invoices were not billed until 2016. The dollars were spent on the purchase and implementation of firewalls.

Internal Technology Development

The Internal Technology Development project consisted of internal labour associated with various projects. More time was shifted to this project, when other projects were delayed or deferred.

In efforts to reduce spending, the Central Filing Document Management project was postponed in an effort to reduce costs. Eventually, Bluewater developed a document management system internally to reduce costs.

Software Upgrades and Additions

As in the prior year, spending was lower than budgeted for Software Upgrades, as they are demand-driven and may not follow budget year patterns.

Central Filing Document Management

This project was postponed in an effort to save reduce costs.

Enterprise Mobility

The Enterprise Mobility project was cancelled, with the plan for it to be reviewed at a later time.

2015 Total Budget vs. Actual: variance -$198,000; -2.8%

Bluewater's 2015 capital expenditures totalled $6,906,313, which was $198,332 less than the budget of $7,104,645. Bluewater's 2015 capital expenditures were near budget. The slight shortfall can mainly be attributed to projects in the General Plant category.

2016 Budget vs. 2016 Actual

2016 System Access: variance -$74,000; -6.0%

In 2016, $1,230,000 was budgeted in the System Access category, and actual expenditures totalled $1,155,985. The variance was -$74,042. The budget versus actual variance of -6.0% in System Access expenditures was under 10% and not material.

2016 System Renewal: variance $180,000; 4.9%

In 2016, $3,686,000 was budgeted in the System Renewal category, and actual expenditures totalled $3,866,289. The variance was $180,289. The budget versus actual variance of 4.9% in System Renewal expenditures was under 10% and not material.

2016 System Service: variance -$393,000, -35.2%

Table 48: 2016 System Service Expenditures ($'000)

Project ID	Project	2016 Budget	2016 Actual	Variance
	MicroFit Projects	300	69	(231)
	Miscellaneous (9 projects, each with variances less than the materiality threshold)	818	656	(162)
	Total	**1,118**	**725**	**(393)**

In 2016, $1,118,000 was budgeted in the System Service category, and actual expenditures totalled $724,621. The variance was -$393,379.

MicroFit Projects

Bluewater planned to implement MicroFit projects in 2016. Two projects went ahead at Substation 1 and Petrolia Service Centre; however, no further suitable locations were identified. As such, actual spending in this project was less than anticipated.

2016 General Plant: variance -$142,000; -5.8%

In 2016, $2,441,190 was budgeted in the General Plant category, and actual expenditures totalled $2,299,116. The variance was -$142,074. The budget versus actual variance of -5.8% in General Plant expenditures was under 10% and not material.

2016 Total Budget vs. Actual: variance -$429,000; -5.1%

Bluewater's 2016 capital expenditures totalled $8,045,984, which was $429,206 less than the budget of $8,475,190. Bluewater's 2016 total capital expenditures were near budget.

2017 Budget vs. 2017 Actual

2017 System Access: variance -$114,000; -9.1%

In 2017, $1,252,250 was budgeted in the System Access category, and actual expenditures totalled $1,138,327. The variance was -$113,923. The budget versus actual variance of -9.1% in System Access expenditures was under 10% and not material.

2017 System Renewal: variance $-93,000; -2.5%

In 2017, $3,697,000 was budgeted in the System Renewal category, and actual expenditures totalled $3,603,772. The variance was -$93,228. The budget versus actual variance of -2.5% in System Renewal expenditures was under 10% and not material.

2017 System Service: variance -$134,000; -18.6%

Table 49: 2017 System Service Expenditures ($'000)

Project ID	Project	2017 Budget	2017 Actual	Variance
UT25	Remote Load Break Switches	158	77	(81)
	Miscellaneous (5 projects, each with variances less than the materiality threshold)	561	509	(52)
	Total	**719**	**585**	**(133)**

In 2017, $719,000 was budgeted in the System Service category, and actual expenditures totalled $585,460. The variance was -$133,540.

Remote Load Break Switches

This project was deferred due to other demand-driven work. It was completed in 2018.

2017 General Plant: variance -$644,000; -20.2%

Table 50: 2017 General Plant Expenditures ($'000)

Project ID	Project	2017 Budget	2017 Actual	Variance
UT10	Vehicle Replacement	847	1,080	233
UT68	Substation #1 Restoration	150	0	(150)
IT9	Disaster Recovery Plan Upgrade Phase I, II, III	144	7	(137)
IT14	Central Filing Document Management	166	0	(166)
	Miscellaneous (18 projects, each with variances less than the materiality threshold)	1,874	1,450	(424)
	Total	**3,181**	**2,537**	**(644)**

In 2017, $3,180,785 was budgeted in the General Plant category, and actual expenditures totalled $2,536,755. The variance was -$644,030.

Vehicle Replacement

The RBD truck planned for the 2015 budget for Vehicle Replacements was delayed to 2017 due to the manufacturer, as noted above.

Disaster Recovery Plan Upgrade Phase I, II, III

The IT Disaster Recovery project was postponed until 2018. It was decided that an internal software development approach was an economically better solution for Bluewater; this project was postponed in 2016. As such, this budget was under spent.

Central Filing Document Management

The Central Filing Document Management System project was put on hold in order to review and assess the best path going forward.

2017 Total Budget vs. Actual: variance -$985,000; -11.1%

Bluewater's 2017 capital expenditures totalled $7,864,314, which was $984,721 less than the budget of $8,849,035. This was largely attributable to construction and vehicle delivery delays in the General Plant category.

2018 Budget vs. 2018 Actual

2018 System Access: variance $52,000; 4.7%

In 2018, $1,115,000 was budgeted in the System Access category, and actual expenditures totalled $1,167,488. The variance was $52,488. The budget versus actual variance of 4.7% in System Access expenditures was under 10% and not material.

2018 System Renewal: variance -$521,000; -10.7%

Table 51: 2018 System Renewal Expenditures ($'000)

Project ID	Project	2018 Budget	2018 Actual	Variance
UT15	Wood Pole Replacement Program	2,000	1,706	(294)
UT26	Primary Underground Cable Replacements	650	540	(111)
UT48	Emergency Primary Line Replacement	50	191	141
UT60	Vault 'K' on George St. Concrete Lid/Panel	110	9	(101)
	Miscellaneous (17 projects, each with variances less than the materiality threshold)	1,935	1,876	(59)
	Total	**4,895**	**4,374**	**(521)**

In 2018, $4,895,000 was budgeted in the System Renewal category, and actual expenditures totalled $4,373,544. The variance was -$521,456.

Wood Pole Replacement Program

The Wood Pole Replacement program was budgeted based on prior years' actuals and to meet demand of critical rotten poles identified to be replaced, attributing to the variance.

Primary Underground Cable Replacements

The project was completed under the estimated budget.

Emergency Primary Line Replacement

Emergency replacements represent unplanned failures, and as such, more was spent than anticipated on replacements in 2018.

Vault 'K' on George St. Concrete Lid/Panel

This project was deferred due to other demand-driven work. It was completed in 2019.

2018 System Service: variance $15,000; 1.9%

In 2018, $775,000 was budgeted in the System Service category, and actual expenditures totalled $789,584. The variance was $14,584. The budget versus actual variance of 1.9% in System Service expenditures was under 10% and not material.

2018 General Plant: variance -$70,000; -2.9%

In 2018, $2,432,325 was budgeted in the General Plant category, and actual expenditures totalled $2,362,699. The variance was -$69,626. The budget versus actual variance of -2.9% in General Plant expenditures was under 10% and not material.

2018 Total Budget vs. Actual: variance -$524,000; -5.7%

Bluewater's 2018 capital expenditures totalled $8,693,315, which was $524,010 less than the budget of $9,214,325. Expenditures in 2018 were near budget.

2019 Budget vs. 2019 Actual

2019 System Access: variance $330,000; 27.5%

In 2019, $1,200,000 was budgeted in the System Access category, and actual expenditures totalled $1,529,503. The variance was $329,503.

Table 52: 2019 System Access Expenditures ($'000)

Project ID	Project	2019 Budget	2019 Actual	Variance
UT11	New Connections, Upgrades, Subdivisions	800	1,264	464
	Miscellaneous (3 projects, each with variances less than the materiality threshold)	400	265	(135)
	Total	**1,200**	**1,530**	**330**

New Connections, Upgrades, Subdivisions

This project is demand-driven by new residential and commercial connections.

2019 System Renewal: variance -$237,000; -4.4%

In 2019, $5,340,000 was budgeted in the System Renewal category, and actual expenditures totalled $5,102,931. The variance was -$237,069. The budget versus actual variance of -4.4% in System Renewal expenditures was under 10% and not material.

2019 System Service: variance -$5,000; -5.3%

In 2019, $260,000 was budgeted in the System Service category, and actual expenditures totalled $246,331. The variance was -$13,669. The budget versus actual variance of -5.3% in System Service expenditures was under 10% and not material.

2019 General Plant: variance -$463,000; -14.9%

In 2019, $3,099,390 was budgeted in the General Plant category, and actual expenditures totalled $2,636,055. The variance was -$463,335.

Table 53: 2019 General Plant Expenditures ($'000)

Project ID	Project	2019 Budget	2019 Actual	Variance
UT12	Transformers	150	247	97
UT19	Service Centre	450	193	(257)
IT6	Software-Upgrades and Additions	284	111	(172)
IT32	Utilismart RSVA	114	33	(81)
	Miscellaneous (17 projects, each with variances less than the materiality threshold)	2,102	2,051	(51)
	Total	**3,099**	**2,636**	**(463)**

Transformers

Increased demand required increased inventory requirements. Distribution transformers in inventory enables the Bluewater to quickly respond to distribution transformer failures that have reached their end of useful life or from storm-related damage.

Service Centre

This project was under budget because the planned parking lot project was cut and two other projects of lighting upgrade and garage doors came in under budget.

Software-Upgrades and Additions

This project was under budget because there was a reallocation of costs to the O&M budget for certain Microsoft software. As well, there were fewer requests for software purchases than anticipated.

Utilismart RSVA

This project was under budget in 2019 because the project was not completed and carried over into 2020. There was a considerable amount of capitalized labour that was part of the project that occurred in 2019.

2019 Total Budget vs. Actual: variance -$385,000; -3.9%

Bluewater's 2019 capital expenditures totalled $9,541,820, which was $384,570 less than the budget of $9,899,390. Expenditures in 2019 were near budget.

2020 Budget vs. 2020 Actual

2020 System Access: variance $644,000; 61.4%

In 2020, $1,050,000 was budgeted in the System Access category, and actual expenditures totalled $1,694,210. The variance was $644,210.

Table 54: 2020 System Access Expenditures ($'000)

Project ID	Project	2020 Budget	2020 Actual	Variance
UT11	New Connections, Upgrades, Subdivisions	900	1,246	346
M1	Single Phase Meters and Poly Phase Meters	100	396	296
	Miscellaneous (1 project with variances less than the materiality threshold)	50	52	2
	Total	**1,050**	**1,694**	**644**

New Connections, Upgrades, Subdivisions

This project is demand-driven by new residential and commercial connections.

Single Phase Meters and Poly Phase Meters

This project came in over budget because meters were ordered for 2019 but they were delayed and did not arrive until 2020. Additionally, more Poly Phase meters than normal were required to complete sample groups.

2020 System Renewal: variance -$784,000; -14.8%

In 2020, $5,290,000 was budgeted in the System Renewal category, and actual expenditures totalled $4,506,369. The variance was -$783,631

Table 55: 2020 System Renewal Expenditures ($'000)

Project ID	Project	2020 Budget	2020 Actual	Variance
UT5	Petrolia	250	6	(244)
UT7	4 kV Lines Rebuild/ Load Conversion	500	187	(313)
UT15	Wood Pole Replacement Program	2,200	2,316	116
UT18	Unforeseen Capital Fund	250	85	(165)
UT36	Downtown Secondary Network Cable Replacement	350	499	149
UT53	1F8 Lead Cable Elimination	250	2	(248)
	Miscellaneous (14 projects with variances less than the materiality threshold)	1,490	1,411	(79)
	Total	**5,290**	**4,506**	**(784)**

Petrolia

This project came in under budget due lack of available workforce associated with the Pandemic and was moved to 2021.

4 kV Lines Rebuild/ Load Conversion

This project was put on hold due to the Pandemic and was moved to 2021.

Wood Pole Replacement Program

Commercially dense area requiring replacement resulted in higher costs per pole.

Unforeseen Capital Fund

This project is an emergency fund, and spending within it was not needed in this year.

Downtown Secondary Network Cable Replacement

This project was over budget due to the unforeseen replacements required once workers attended field.

1F8 Lead Cable Elimination

This project was put on hold due to the Pandemic and was moved to 2021.

2020 System Service: variance -$54,000; -14.0%

In 2020, $350,000 was budgeted in the System Service category, and actual expenditures totalled $300,893. The variance was -$49,107.

Table 56: 2020 System Service Expenditures ($'000)

Project ID	Project	2020 Budget	2020 Actual	Variance
UT25	Remote Load Break Switches	90	62	(28)
	Miscellaneous (3 projects, each with variances less than the materiality threshold)	260	239	(21)
	Total	**350**	**301**	**(49)**

Remote Load Break Switches

This project was put on hold due to the Pandemic.

2020 General Plant: variance -$230,000; -7.0%

In 2020, $3,291,570 was budgeted in the General Plant category, and actual expenditures totalled $3,061,746. The variance was -$229,824. The budget versus actual variance of -7.0% in General Plant expenditures was under 10% and not material.

2020 Total Budget vs. Actual: variance -$418,000; -4.2%

Bluewater's 2020 capital expenditures totalled $9,563,218, which was $418,352 less than the budget of $9,981,570. Expenditures in 2020 were near budget.

2021 Budget vs. 2021 Actual

2021 System Access: variance $564,000; 40.3%

In 2021, $1,400,000 was budgeted in the System Access category, and actual expenditures totalled $1,964,320. The variance was $564,320.

Table 57: 2021 System Access Expenditures ($'000)

Project ID	Project	2021 Budget	2021 Actual	Variance
UT3	Street Widening	150	18	(132)
UT11	New Connections, Upgrades, Subdivisions	1,100	1,832	732
	Miscellaneous (2 projects with variances less than the materiality threshold)	150	114	(36)
	Total	**1,400**	**1,964**	**564**

Street Widening

The municipal street widening project was deferred by the Town of Petrolia.

New Connections, Upgrades, Subdivisions

This project is demand-driven by new residential and commercial connections.

2021 System Renewal: variance -$1,829,000; -34.1%

In 2021, $5,370,000 was budgeted in the System Renewal category, and actual expenditures totalled $3,540,615. The variance was -$1,829,385.

Table 58: 2021 System Renewal Expenditures ($'000)

Project ID	Project	2021 Budget	2021 Actual	Variance
UT7	4 kV Lines Rebuild/ Load Conversion	200	5	(195)
UT15	Wood Pole Replacement Program	2,250	1,563	(687)
UT24	Storm Restoration	250	569	319
UT26	Primary Underground Cable Replacements	300	42	(258)
UT35	Substation Transformer Replacements	350	154	(196)
UT36	Downtown Secondary Network Cable Replacement	400	129	(271)
UT53	1F8 Lead Cable Elimination	150	7	(143)
UT71	PCB Tx Replacement	150	28	(122)
	Miscellaneous (16 projects with variances less than the materiality threshold)	1,320	1,044	(275)
	Total	**5,370**	**3,541**	**(1,829)**

4 kV Lines Rebuild/ Load Conversion

This project was placed on hold due to demand-driven work taking priority and was moved to 2022.

Wood Pole Replacement Program

This project was under budget due to lack of workforce caused by the Pandemic and will continue in 2022.

Storm Restoration

This project came in over budget due to more storms occurring than normal.

Primary Underground Cable Replacement

This project was not completed due to locates from other utilities not being provided in time to schedule work. The project was moved to 2022.

Substation Transformer Replacements

This project involved purchasing and installing a backup transformer at Bluewater's last 8 kV substation. The transformer was purchased but the installation part of the project was eliminated after Bluewater determined the risk of failure of the transformer currently in use was low and that the new transformer could be installed quickly if needed.

Downtown Secondary Network Cable Replacement

This project was placed on hold due to demand-driven work taking priority. Materials were purchased and the project was moved to 2022.

1F8 Lead Cable Elimination

This project was placed on hold due to demand-driven work taking priority and moved to 2022.

PCB Tx Replacement

This phase of the project involved field checks on transformers. Manpower prohibited us from checking as many as planned and the project will continue in 2022.

2021 System Service: variance -$52,000; -10.8%

In 2021, $410,000 was budgeted in the System Service category, and actual expenditures totalled $365,923. The variance was -$44,077.

Table 59: 2021 System Service Expenditures ($'000)

Project ID	Project	2021 Budget	2021 Actual	Variance
UT33	Animal Protection	150	105	(45)
	Miscellaneous (3 projects, each with variances less than the materiality threshold)	260	261	1
	Total	**410**	**366**	**(44)**

Animal Protection

This project came in under budget due to workforce resourcing.

2021 General Plant: variance -$524,000; -14.3%

In 2021, $3,660,000 was budgeted in the General Plant category, and actual expenditures totalled $3,136,381. The variance was -$523,619.

Table 60: 2021 General Plant Expenditures ($'000)

Project ID	Project	2021 Budget	2021 Actual	Variance
UT10	Vehicle Replacement	605	515	(90)
IT1	Data Centre Lifecycle	250	396	146
IT3	Corporate IT Security	250	160	(90)
IT5	Legislated Business Application Upgrades	200	80	(120)
IT9	Disaster Recovery Plan Upgrade Phase I, II, III	125	36	(89)
IT32	Utilismart RSVA	0	106	106
IT35	Business Technology Improvements	200	0	(200)
	Miscellaneous (14 projects, each with variances less than the materiality threshold)	2,030	1,843	(187)
	Total	**3,660**	**3,136**	**(524)**

Vehicle Replacement

A vehicle that was budgeted for in 2021 was delayed to reduce costs.

Data Centre Lifecycle

The overage was due, in part, to a misallocation of capitalized labour, which should have gone to IT3 (Corporate Security)

Corporate IT Security

This project was under due to a misallocation of capitalized labour, which was charged to IT1 (Data Centre Lifecycle).

Legislated Business Application Upgrades

There were fewer hours necessary to complete legislated change requirements in 2021.

Disaster Recovery Plan Upgrade Phase I, II, III

Projects associated with this capital item were delayed due to COVID.

Utilismart RSVA

The RSVA project was budgeted to complete in 2020 but didn't. Instead, it carried over into 2021 where a final payment was made upon project completion. However, the extension was not identified until after the 2021 budget was completed and was not carried over into 2021.

Business Technology Improvements

Because of the carryover of the RSVA project and because of COVID, this project was delayed.

2021 Total Budget vs. Actual: variance -$1,832,761; -16.9%

Bluewater's 2021 capital expenditures totalled $9,007,239, which was $1,832,761 less than the budget of $10,840,000. Expenditures in 2021 varied from budget largely due to delayed projects. Those projects were delayed due to workforce capacity issues driven by COVID and demands from non-capital projects. Any capital project delayed remains a priority, but has been rescheduled as set out in the write-up above.

5.4.1.2 Forecast Expenditures

The following section provides an analysis of Bluewater's forecast capital expenditures. While the majority of Bluewater's capital is allocated to ongoing programs, there are some distinct projects in the forecast period.

In the years 2024-2027, Bluewater has included the "Innovation Research" budget for capital investments to further pilot studies, as necessary, to further the goal of adapting to demands from customers, as well as distribution system innovations being explored in the industry. As customer-driven technologies emerge, Bluewater will strive to be in a position to accommodate their implementation. In the past, Bluewater has demonstrated an eagerness to work with its customers and various project proponents. Bluewater intends to build on its successful customer relations by preparing its infrastructure to enable innovation projects in a safe, timely, technically sound, and efficient manner.

Throughout 2021 and 2022 Bluewater has faced inflationary pressure on its expenses. In 2021, Bluewater saw on increase to the moving average cost of its materials of approximately 8.6%. As of July 2022, Bluewater has seen a further average increase in the moving average cost of its materials of approximately 9.8% over 2021 costs.

In developing its 5 year financial forecast (2023 budget and 2024-27 forecast) Bluewater first updated its 2022 forecast. The 2022 forecast is based on a combination of actual results as of May 31, 2022 and estimated expenses for the remainder of the year.

The 2023 Budget contains the following estimated inflationary increases over 2022:

- Union represented labour, as determined by the collective agreement: 2%
- Non-Union represented labour: 4%
- Known inflationary increases were incorporated, otherwise inflation on materials: 10%

For the 2024-27 forecast an annual 3% inflationary increase was used.

Finally, the increase to Bluewater’s capital budget has resulted in increased numbers of vehicles, equipment, and inventory. As a result, Bluewater is considering garage modifications or expansions in future years to accompany this growth. The cost and timing of this potential project is uncertain, and as such has not been included in the DSP.

The table below outlines Bluewater’s projects from 2023-2027 along with their capital expenditure amount for each year.

Table 61: Capital Expenditures by Project 2023-2027

Project ID	**Project Name**	**Category**	2023	2024	2025	2026	2027
UT1	Substation Building	General Plant	$ 82,500	$ 85,000	$ 87,600	$ 90,200	$ 92,900
UT9	Tools (Vehicle and others)	General Plant	$ 88,000	$ 90,600	$ 93,300	$ 96,100	$ 99,000
UT10	Vehicle Replacement	General Plant	$ 270,000	$ 425,000	$ 105,000	$ 385,000	$ 590,000
UT12	Transformers	General Plant	$ 165,000	$ 170,000	$ 175,100	$ 180,400	$ 185,800
UT13	Safety Related Projects	General Plant	$ 27,500	$ 28,300	$ 29,100	$ 30,000	$ 30,900
UT19	Service Centre	General Plant	$ 150,000	$ 158,600	$ 163,400	$ 168,300	$ 173,300
UT69	Pole Testing Tools	General Plant	$ 33,000		$ -		
M4	Metering Equipment/Tools	General Plant	$ 5,500	$ 5,700	$ 5,900	$ 6,100	$ 6,300
IT1	Data Centre Lifecycle	General Plant	$ 185,000	$ 190,600	$ 376,700	$ 213,100	$ 208,300
IT2	Computer Infrastructure Lifecycle	General Plant	$ 200,000	$ 206,000	$ 212,200	$ 229,500	$ 253,300
IT3	Corporate IT Security	General Plant	$ 220,000	$ 190,600	$ 164,500	$ 234,900	$ 270,200
IT4	Internal Technology Development	General Plant	$ 425,000	$ 463,500	$ 477,400	$ 491,700	$ 506,500
IT5	Legislated Business Application Upgrades	General Plant	$ 300,000	$ 293,600	$ 302,400	$ 218,600	$ 225,100
IT6	Software-Upgrades and Additions	General Plant	$ 110,000	$ 206,000	$ 238,800	$ 245,900	$ 253,300
IT9	Disaster Recovery Plan Upgrade Phase I,II,III	General Plant	$ 158,000	$ 118,500	$ 114,500	$ 196,700	$ 168,800
IT21	Mailroom Equipment Replacement	General Plant					$ 43,400
IT35	Business Technology Improvements	General Plant	$ 435,000	$ 515,000	$ 1,061,000	$ 1,092,800	$ 1,125,600
O3	Furniture (Company wide)	General Plant	$ 22,000	$ 22,700	$ 23,400	$ 24,000	$ 24,700
General Plant Total			**$ 2,876,500**	**$ 3,169,700**	**$ 3,630,300**	**$ 3,903,300**	**$ 4,257,400**

UT3	Street Widening	System Access	$ 53,000	$ 54,600	$ 56,200	$ 57,900	$ 59,000
UT11	New Connections, Upgrades, Subdivisions	System Access	$ 2,110,000	$ 2,176,600	$ 2,241,900	$ 2,309,200	$ 2,351,500
M1	Single Phase Meters and Poly Phase Meters	System Access	$ 104,500	$ 107,600	$ 110,800	$ 114,100	$ 115,900
M3	New Meters	System Access	$ 54,500	$ 107,600	$ 110,800	$ 114,100	$ 115,900
System Access Total			**$ 2,322,000**	**$ 2,446,400**	**$ 2,519,700**	**$ 2,595,300**	**$ 2,642,300**
UT5	Petrolia	System Renewal	$ 208,000	$ 107,100	$ 110,300	$ 113,600	$ 115,200
UT6	Alvinston/Oil Springs Capital Items	System Renewal	$ 20,600	$ 21,200	$ 21,800	$ 22,500	$ 22,800
UT7	4KV Lines Rebuild/ Load Conversion	System Renewal	$ 210,000	$ 213,300	$ 219,700	$ 226,300	$ 230,100
UT8	Pt Edward upgrades	System Renewal	$ 51,300	$ 52,800	$ 54,400	$ 56,000	$ 56,600
UT14	Cross Arm/Cap & Pin Insulator Replacement Program	System Renewal	$ 153,000	$ 157,600	$ 162,300	$ 167,200	$ 168,600
UT15	Wood Pole Replacement Program	System Renewal	$ 1,957,000	$ 2,016,000	$ 2,076,000	$ 2,138,000	$ 2,202,000
UT16	Watford	System Renewal	$ 208,000	$ 107,100	$ 110,300	$ 113,600	$ 115,200
UT18	Unforeseen Capital Fund	System Renewal	$ 175,000	$ 180,000	$ 185,000	$ 191,000	$ 197,000
UT22	8 kv Load Conversion	System Renewal	$ 372,500	$ 379,900	$ 391,300	$ 403,000	$ 411,300
UT24	Storm Restoration	System Renewal	$ 385,000	$ 396,600	$ 408,500	$ 420,800	$ 421,900
UT26	Primary Underground Cable Replacements	System Renewal	$ 322,000	$ 331,700	$ 341,700	$ 352,000	$ 360,200
UT31	Pad Mount Transformer Replacements	System Renewal	$ 82,500	$ 85,000	$ 87,600	$ 90,200	$ 91,300
UT34	27.6kV Lines Upgrades	System Renewal	$ -	$ 101,700	$ 104,800	$ 107,900	$ 109,800
UT40	Guy Guard/Down Guy Replacement	System Renewal	$ 25,300	$ 20,800	$ 21,400	$ 22,000	$ 22,700
UT47	Emergency Transformer Replacement	System Renewal	$ 262,500	$ 270,400	$ 278,500	$ 286,900	$ 291,800
UT48	Emergency Primary Line Replacement	System Renewal	$ 83,500	$ 86,000	$ 88,600	$ 91,300	$ 92,700
UT49	Emergency Secondary Line Replacement	System Renewal	$ 37,300	$ 27,100	$ 27,900	$ 28,700	$ 29,200
UT57	Downtown Vault Upgrades	System Renewal	$ 10,400	$ 10,500	$ 10,800	$ 11,100	$ 11,300
UT61	Subdivision Transformers	System Renewal	$ 79,000	$ 80,300	$ 82,700	$ 85,200	$ 86,700

UT64	PMH (Pad-Mount) Switchgear Replacement	System Renewal	$ 54,000	$ 55,300	$ 57,000	$ 58,700	$ 60,200
UT71	PCB Tx Replacement	System Renewal	$ 157,500	$ 160,000			
UT72	St. Clair Parkway in Sarnia (North of LaSalle Line)	System Renewal	$ 262,500				
UT73	Albany Substation breaker upgrade	System Renewal	$ 210,000				
UT74	4kV System Upgrades	System Renewal	$ 817,500				
UT76	Downtown Switch Replacement	System Renewal	$ 131,300	$ 133,400			
UT77	Centre St Pet	System Renewal		$ 515,000			
UT78	Cable Theft Replacement	System Renewal	$ 11,000	$ 11,300	$ 11,600	$ 11,900	$ 12,300
UT21	27.6 Kv Feeder Extensions	System Renewal	$ 372,500	$ 379,900	$ 391,300	$ 403,000	$ 411,300
System Renewal Total			**$ 6,659,200**	**$ 5,900,000**	**$ 5,243,500**	**$ 5,400,900**	**$ 5,520,200**
UT25	Remote Load Break Switches	System Service	$ 96,500	$ 98,600	$ 101,600	$ 104,600	$ 107,000
UT30	Fault Indicators - Overhead	System Service	$ 10,800	$ 11,100	$ 11,400	$ 11,700	$ 12,000
UT33	Animal Protection	System Service	$ 21,100	$ 21,500	$ 22,100	$ 22,800	$ 23,200
	Telecommunications - Operations	System Service	$ 375,000				
UT83	Distribution Transformer Monitoring Grid 20/20	System Service	$ 11,000	$ 11,300	$ 11,600	$ 12,100	$ 12,500
	Innovation Research	System Service		$ 51,500	$ 53,000	$ 54,600	$ 56,200
System Service Total			**$ 514,400**	**$ 194,000**	**$ 199,700**	**$ 205,800**	**$ 210,900**
GRAND TOTAL			**$ 12,372,100**	**$ 11,710,100**	**$ 11,593,200**	**$ 12,105,300**	**$ 12,630,800**

5.4.1.3 Non-distribution activities

There are no expenditures for non-distribution activities in Bluewater's budget.

5.4.2 Justifying Capital Expenditures

Bluewater's DSP is focused on controlling costs while delivering value to its customers. Detailed justifications for Bluewater's 2023 material capital projects may be found in Appendix F.

In planning its five year forecast, Bluewater endeavoured to develop a capital budget that was sustainable and levelize spending in order to provide customers with smooth rate impacts. For reference, Bluewater's proposed five year capital spending can be found in Table 62.

Table 62: Forecast Capital Expenditures ($'000)

CATEGORY	2023 Test Year	2024	2025	2026	2027
System Access	2,322	2,446	2,520	2,595	2,642
System Renewal	6,659	5,900	5,244	5,401	5,520
System Service	514	194	200	206	211
General Plant	2,877	3,170	3,630	3,903	4,257
Total Expenditure	**12,372**	**11,710**	**11,593**	**12,105**	**12,631**

5.4.2.1 Forecast Impact on O&M Costs

Bluewater's distribution system plan is designed to pace investments at a level that maintains the overall health of the system's assets. Each year, the distribution system assets age and deteriorate further. Replacing deteriorating assets that are most at risk of failure helps Bluewater avoid increased failures, emergency repairs and increased O&M costs. Planned replacement of assets, as well projects such as additional animal protection and moving back-lot distribution assets to the street, will result in decreased unplanned outages and emergency repairs however these expenses are primarily capital in nature.   In addition, voltage conversion projects will help reduce system line losses, providing a direct benefit to customers, but typically not related to O&M costs.

5.4.2.2 Investment Drivers by Category

System Access

System Access investments are driven by statutory, regulatory, or other obligations on Bluewater to provide customers with access to the local distribution system.

The two main drivers for this category have historically been and are expected to continue to be new and upgraded services for customers and infrastructure relocations to accommodate municipal projects.

While there have been fluctuations year to year, the average spending over the five year forecast is expected to be consistent, although slightly less than the previous five years.

System Renewal

System Renewal investments are driven by the relationship between the ability of an asset to continue to perform at an acceptable standard on a predictable basis and the consequences for customers served by the asset if the asset fails. Investments include replacing assets or refurbishing them to extend their useful service life.

The main drivers for this category are the condition of the assets and the risks they impose on the safety and reliability of the electrical grid. The condition of assets is determined by the ACA report and subsequent inspections.

The level of investments in this category for the next five years is expected to be higher than the previous five years, as larger quantities of assets are beginning to exceed their useful lives and continue to degrade, and additional information and analysis has been obtained over the past few years, which has highlighted the need to increase the level of investment.

System Service

System Service investments are driven by expectations that evolving customer use of the system may create system capacity constraints or otherwise adversely impact operations and the delivery of quality distribution services.

The main drivers for this category are reliability and flexibility of the grid. Investments made to extend the 27.6 kV main feeders provide a more robust grid with the flexibility to serve major load areas with more than one supply point. Investments in technology improve the reliability and flexibility of the system.

Through customer engagement activities, customers have confirmed that they value Bluewater's expertise in replacing deteriorating infrastructure and maintaining system reliability, even if it may result in an increase to the electricity bill.

The forecast spending for the next five years is expected to be slightly higher than to the previous five years.

General Plant

General Plant investments are driven by Bluewater's evolving requirements for capital to support the day-to-day business and operations activities.

The main drivers for this category are the on-going replacement of non-distribution assets (including fleet, facilities, and IT) that become unreliable, obsolete, or costly to maintain, as well as the increasing desire of customers to have better access to more information and services.

The forecast for the next five years is expected to be slightly more than the previous five years, which reflects the overall higher replacement cost of fleet, facilities, and IT assets.

5.4.2.3 Material Investments

For this DSP, Bluewater has created Capital Project sheets for all 2023 projects greater than or equal to the materiality threshold of $130,000. The capital project sheets are located in Appendix F: Capital Project Sheets, with a summary of the projects listed in Table 62. Comparative historical expenditures may be found in Table 38, above.

Table 63: 2023 Test Year Material Capital Projects (materiality threshold of $130,000)

Category	Category Total Budget ($'000)	Project ID	Material Project Name	Budget ($'000)
General Plant	2,877	UT10	Vehicle Replacement	270
		UT12	Transformers	165
		UT19	Service Centre	150
		IT1	Data Centre Lifecycle	185
		IT2	Computer Infrastructure Lifecycle	200
		IT3	Corporate IT Security	220
		IT4	Internal Technology Development	425
		IT5	Legislated Business Application Upgrades	300
		IT9	Disaster Recovery Plan Upgrade Phase I, II, III	158
		IT35	Business Technology Improvements	435
System Access	2,322	UT11	New Connections, Upgrades, Subdivisions	2,110
System Renewal	6,659	UT5, 16	Petrolia / Watford	416
		UT7	4 kV Lines Rebuild/ Load Conversion	210
		UT14	Cross Arm/Cap & Pin Insulator Replacement Program	153
		UT15	Wood Pole Replacement Program	1,957
		UT18	Unforeseen Capital Fund	175
		UT21, 22	27.6 kV Feeder Extensions, 8 kV Load Conversion	745
		UT24	Storm Restoration	385
		UT26	Primary Underground Cable Replacements	322
		UT47	Emergency Transformer Replacement	263
		UT71	PCB Tx Replacement	158
		UT72	St. Clair Parkway in Sarnia (North of LaSalle Line)	263
		UT73	Albany Substation Breaker Upgrade	210
		UT74	4 kV System Upgrades	818
		UT76	Downtown Switch Replacement	131
System Service	514		Telecommunications – Operations	375

Appendix A

Asset Condition Assessment Report

BLUEWATER POWER DISTRIBUTION
2021 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-814261-RA-0001-R00

October 25, 2021

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON M8Z 5G5
Canada

www.kinectrics.com

DISCLAIMER

BLUEWATER POWER DISTRIBUTION
2021 ASSET CONDITION Assessment

Kinectrics Report: K-814261-RA-0001-R00

October 25, 2021

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Revision History

Revision Number	Date	Comments	Approved
R00	2021-07-19	Draft	
	2021-10-25	Final	

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Introduction

Bluewater Power Distribution (BWP) recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. An assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan. This undertaking is spanning several years and, thus, allows BWP to monitor the trend in asset condition changes and to incrementally improve its assessment process and asset management practices.

In early 2014, BWP selected and engaged Kinectrics Inc. (Kinectrics) to perform an ACA on BWP's key distribution assets. The same type of ACA study was conducted again by Kinectrics in 2015, 2016, 2017, 2018, 2019 and 2020. This report presents assessment results and is based on the available condition data as of the end of December 2020, as well as the audit on the changes since the 2020 ACA study.

The category and sub-categories of assets included in this study are as follows:

- MS Transformers

- MS Circuit Breakers
    - Air Magnetic
    - Bulk Oil
    - Vacuum

- MS Switchgear

- Pole Top Transformers
    - Single Phase
    - Poly Phase
    - Rabbit Type

- Gang Operated Overhead Switches
    - Manual
    - Motorized

- Wood Poles

- Underground Cables
    - XLPE Direct Buried
    - XLPE In Duct
    - PILC

- Pad Mounted Transformers
    - Single Phase
    - Three Phase

- Pad Mounted Switchgear

For each asset category, the Health Index formulation, Health Index distribution, condition-based flagged-for-action plan, and a data assessment in terms of the data availability indicator (DAI) and data gap analysis are given.

Definitions

Terminology	Acronym	Definition
Asset Condition Assessment	ACA	Process of using asset information to determine the condition of assets. Condition data can include nameplate information, test results, asset inspection records, corrective maintenance records, operational experience, etc.
Condition Parameter Score	CPS	Score of an asset for a particular condition parameter. In this study, the scoring system used ranges from 0 through 4 (0 = worst; 4 = best).
Condition Parameters	CP	Asset characteristics or properties that are used to derive the HI.
Criticality		Metric used to quantify consequence of failure in this methodology.
Criticality Index	CI	Index used to determine asset Criticality. CI ranges from 0% to 100%, with 100% representing the unit with the highest possible consequence of failure.
Cumulative Distribution Function	CDF	Cumulative distribution function, representing the cumulative likelihood of removals.
Data Availability Indicator	DAI	A measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the HI formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score
Data Gap		A data gap is the case where none of the units in an asset group has data for a particular item. For example, the data is either unavailable or not in a useable format.

Terminology	Acronym	Definition
De-rating Multiplier	DR	Multipliers used to adjust a condition or sub-condition parameter score or calculated Health Index so as to reflect certain conditions.
Failure Rate		Hazard function. Assumed in this methodology as the rate of removal (removals per year for given age, including failures, proactively replaced, removal for non-condition reasons).
Flagged for Action Plan	FFA Plan	Number of units that are expected to require attention annually.
Flagged for Action Year	FFA Year	The year that a particular unit is flagged for action.
Health Index	HI	Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the factors that cumulatively lead to an asset's end of life. HI is given in terms of a percentage range of 0%-100%, with 100% representing as new condition.
Risk		Product of likelihood of removal and consequence of failure.
Sample Size		Subset of an asset population with enough data (i.e. age or condition data) to calculate the HI.
Sub-Condition Parameter Score	SCPS	Score of an asset for a particular sub condition parameter. In this study, the scoring system used ranges from 0 through 4 (0 = worst; 4 = best).
Sub-Condition Parameters	CP	Asset characteristics or properties that are used to derive the HI. Each condition parameter can be comprised of multiple sub-condition parameters.
Weight of Condition Parameter	WCP	In the HI formula, condition parameters are assigned a weight that is based on the degree of contribution or relevance to asset degradation.
Weight of Sub-Condition Parameter	WSCP	In the HI formula, condition parameters are assigned a weight that is based on the degree of contribution or relevance to asset degradation.

Health Index Methodology

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the degradation factors that lead to an asset's end of service life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WSCP_n)}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)}$$

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient (1 if available; 0 if not available)
CPF	Sub-Condition Parameter Score
WSCP	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (1 if available; 0 if not available)
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e., $CPF_{max} = 4$.

De-Rating multipliers are applied to the calculated HI. These may be used to represent the impact of non-condition issues such as design or operating environment.

An asset’s Health Index is given as a percentage, with 100% representing “as new” condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Health Index Results

Table 1 shows a summary of the Health Index evaluation results. Figure 1 presents the same information graphically. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. Also shown are the average Health Index value, Health Index Distribution, and average DAI for each group.

It can be seen from the results that Circuit Breakers (bulk oil type) and Underground Cables category was, on average as an asset group, in the worst condition. All the Circuit Breakers (bulk oil type) were in “poor” condition. About 70% of total length of Direct Buried XLPE Cable and all the PILC Cable were in “poor” or “very poor” condition.

Other groups of concern were MS Switchgear, and single-phase Pole Top Transformers. The percentages of assets in “poor” or “very poor” condition are 38% and 22% respectively.

Table 1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
MS Transformers		21	21	80%	1	1	3	4	12	35	80%	100%
MS Circuit Breakers	Air Magnetic	41	41	69%	0	0	23	18	0	60	82%	100%
	Bulk Oil	3	3	30%	0	3	0	0	0	74	38%	100%
	Vacuum	7	7	92%	0	0	0	0	7	19	29%	100%
MS Switchgear		21	21	55%	0	8	8	2	3	49	67%	100%
Pole Top Transformers	Single Phase	2003	1993	77%	374	56	57	103	1403	31	99%	70%
	Poly Phase	598	591	88%	51	13	20	19	488	24	96%	71%
	Rabbit Type	43	43	98%	0	0	0	1	42	16	86%	63%
Gang Operated Overhead Switches		132	103	99%	1	0	0	0	102	16	75%	30%
Wood Poles		15361	15320	66%	1154	21	751	12792	602	29	85%	46%
Underground Cables *	XLPE Direct Buried	65.7	44.3	32%	26.5	4.2	0.9	6.1	6.7	41	67%	67%
	XLPE In Duct	179.9	122.3	97%	1.8	2.6	0.0	0.7	117.2	17	68%	68%
	PILC	0.5	0.5	0%	0.5	0.0	0.0	0.0	0.0	81	100%	100%
Pad Mounted Transformers	Single Phase	1272	1272	95%	10	7	31	75	1149	28	99%	88%
	Three Phase	281	279	93%	1	4	24	23	227	28	97%	87%
Pad Mounted Switchgear		18	18	88%	0	1	2	2	13	15	61%	78%

* by length (km)

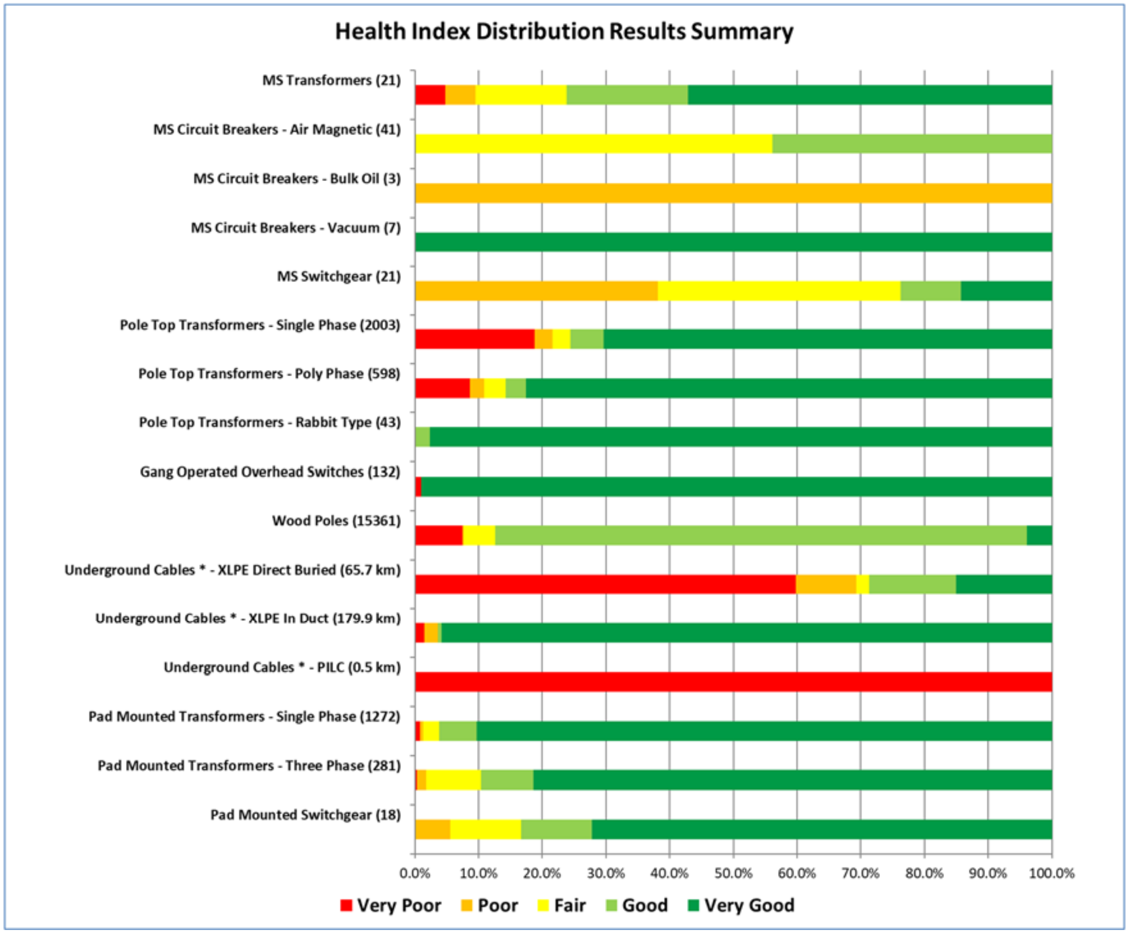

Figure 1 Health Index Results Summary (Graphical)

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Condition Based Flagged-for Action Plan

The condition-based Flagged-for-Action plan for the first year and 10-year strategy is shown for each asset group in Table 2. Table 3 shows the 20 year Flagged-for-Action plan. It should be noted that for some asset categories the quantity determined for the current year plan, shown in Table 2, may be significantly larger than the quantities determined for near future subsequent years. This is generally the case when there is a large quantity of assets that are at or very near the end of their maximum useful lives. Because such assets would have a high failure rate, large quantities will be flagged for intervention in the first year. Since the assessment methodology assumes that all units flagged for intervention are replaced, the quantities determined for near future subsequent years may be significantly smaller than that of the first year. In reality, only some of the units flagged for action in the first year will be dealt with while the remaining units will be addressed in subsequent years.

Table 2 Condition-Based Short-Term Flagged-for-Action Plan

Asset Category		1st Year		10 Year Replacement		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
MS Transformers		2	9.5%	2	9.5%	Proactive
MS Circuit Breakers	Air Magnetic	0	0.0%	0	0.0%	Proactive
	Bulk Oil	3	100.0%	3	100.0%	Proactive
	Vacuum	0	0.0%	0	0.0%	Proactive
MS Pad Mounted Switchgear		8	38.1%	14	66.7%	Proactive
Pole Top Transformers	Single Phase	200	10.0%	522	26.1%	Reactive
	Poly Phase	30	5.0%	91	15.2%	Reactive
	Rabbit Type	0	0.0%	0	0.0%	Reactive
Gang Operated Overhead Switches		1	0.8%	1	0.8%	Reactive
Wood Poles		1059	6.9%	8594	55.9%	Proactive/Reactive
Underground Cables *	XLPE Direct Buried	33.6	51.1%	60.3	91.7%	Proactive/Reactive
	XLPE In Duct	3.4	1.9%	15.5	8.6%	Reactive
	PILC	0.5	100.0%	0.5	100.0%	Reactive
Pad Mounted Transformers	Single Phase	7	0.6%	38	3.0%	Reactive
	Three Phase	3	1.1%	25	8.9%	Reactive
Pad Mounted Switchgear		1	5.6%	3	21.4%	Reactive

* by length (km)

It is important to note that the flagged-for-action plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. While the Condition-Based Flagged-for-Action Plan can be used as a guide or input to BWP's Distribution System Plan, it is not expected that it be followed directly or as the final deciding factor in making sustainment capital decisions. There are numerous other factors and considerations that will influence BWP's Asset Management decisions, such as obsolescence, system expansion, regulatory requirements, municipal demands, etc.

In the first year of the 10-year replacement strategy, all bulk oil Circuit Breakers, 38% of MS Switchgear, 51% of directly buried XLPE Underground Cable and all PILC Cable were flagged for action.

During the 10-year period starting from now, all bulk oil Circuit Breakers, 67% of MS Switchgears, 92% of Directly Buried XLPE Underground Cables, all PILC Underground Cables and 56% of Wood Poles were determined to be eligible for replacement.

Table 3 Twenty-Year Condition-Based Flagged-for-Action Plan

Asset Category		Flagged for Action Plan by Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
MS Transformers		2	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0
MS Circuit Breakers	Air Magnetic	0	0	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0
	Bulk Oil	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Vacuum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MS Switchgear		8	0	0	3	0	1	1	0	1	0	0	0	0	1	0	1	0	0	0	0
Pole Top Transformers	Single Phase	200	123	72	42	25	17	13	11	10	9	9	9	9	9	9	9	9	10	10	11
	Poly Phase	30	20	13	8	6	4	3	3	2	2	2	2	2	2	2	2	2	3	3	3
	Rabbit Type	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0
Gang Operated Overhead Switches		1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wood Poles		1059	926	847	809	800	809	824	837	844	839	822	792	749	694	628	554	476	396	319	247
Underground Cables *	XLPE Direct Buried	33.6	8.3	4.6	3.2	2.5	2.1	1.8	1.6	1.4	1.2	0.9	0.6	0.4	0.3	0.2	0.2	0.2	0.2	0.3	0.3
	XLPE In Duct	3.4	1.4	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.6	1.8	2.0	2.2	2.4	2.6	2.8	3.0	3.3	3.5	3.7
	PILC	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pad Mounted Transforme	Single Phase	7	5	4	4	4	3	3	3	3	2	2	2	2	2	3	3	3	3	3	4
	Three Phase	3	3	3	3	3	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Pad Mounted Switchgear		1	0	0	0	1	0	0	1	0	0	1	0	0	0	0	0	1	0	0	0

* by length (km)

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Data Assessment

Data assessment includes determining the data availability indicator (DAI) of each unit, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of data currently available for its respective asset category. Data gaps are items that are indicators of asset degradation, but are currently not collected or available for any asset in an asset category. The more minimal the data gaps, the higher the quality of available condition data and Health Index formulas.

The situation where data is provided for only a sub-set of the population is not considered as a data gap. Instead, it is addressed by DAI.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	☆ ☆ ☆
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	☆ ☆
Low	Helpful data; least indicative of asset deterioration	☆

It is generally recommended that data collection be initiated for the most critical items first because such information will result in higher quality Health Index formulations.

Data for MS Transformers included age, test data, inspection results and loading information. There was no major data gap for this asset group.

Data for MS Circuit Breakers included age, contact resistance, operating counter and inspection results. There was no major data gap for this asset group.

All MS Switchgears had inspection and age data. The major data gap was that some switchgear did not have any data other than age information.

Data for Pole Top Transformers included age and inspection results. The major data gaps were that age information was available for only two thirds of the population, and the existing inspections on pole top transformers do not provide sufficient information required for Health Index calculation, for majority of the population. This applied to all 3 sub-categories.

Data for Gang Operated Overhead Switches included age and inspection results. The major data gaps were that age information was available for less than 30% of the population.

Data for Wood Poles included age and inspection results. The major data gaps were that age information was available for less than half of the population.

For Underground Cables, age was the only information available for assessment. The major data gaps were that age information was available for slightly more than half of the total length of the cables, and there were no historic cable failure records available.

Data for Pad Mounted Transformers included age and inspection results. There was no major data gap for this asset group.

Data for Pad Mounted Switchgear included inspection results and age information. There was no major data gap for this asset group.

In general, lack of age information applied to multiple asset groups, and was extremely severe among Gang Operated Overhead Switches. It is noted that BWP has started standardizing the entries of inspection records. This allows trending on inspection results for condition parameters once sufficient records are collected in the future, which would eventually improve the accuracy of ACA study results.

2020 to 2021 Audit

In 2020 an Asset Condition Assessment (ACA) for key distribution assets was conducted for BWP by Kinectrics based on 2019 data. Since then, BWP took steps to adopt the recommendations prescribed by the 2020 ACA and to improve the quality of its condition data. As described in this report, a subsequent ACA was conducted by Kinectrics for BWP's assets as of 2021 based on the data as of the end of 2020. In addition, Kinectrics assessed the changes with respect to ACA studies between the 2020 and 2021.

Up to year 2020, in Health Index formula asset physical age was used as an overall result limiter for Wood Poles (since 2017 ACA), but as an individual condition parameter for all the other asset groups. As there are more and more units approaching the end of life, using physical age as an individual condition parameter does not accurately reflect the possible ageing degradation. Based on Kinectrics' recent experience in this field, in 2021 ACA study asset physical age was revised to function as an overall Health Index limiter for all the asset groups, the same as the revision made in 2017 ACA for Wood Poles. Weibull distribution curves were adopted to represent their degradation trends, using the parameters based on industry practice.

Because of the above revision, the observed major impact on overall Health Index results was that there were more units flagged for action for some substation asset groups.

This section of the report describes the findings.

Asset Categories

Health Index (HI) formulation and results from 2020 and 2021 were compared for the following Asset Categories and Sub-Categories as mentioned in the Introduction section.

Audit Results

For each Asset Category, the following aspects were compared between 2019 and 2020 studies:

1. Health Index Formulation
2. Population and Sample Size
3. Health Index Distribution

--- Changes in Population and Sample Size

Table 4 summarizes the Change in Population and in Sample Size between the studies done in 2020 and 2021. Graphical representations of the data are given on Figure 2 and Figure 3.

Table 4 Summary Change in Population and Sample Size

Asset		Population				Sample Size		
		Count		Change		%		Change
		2019	2020	By Counts	By %	2019	2020	By %
MS Transformers		21	21	0	0%	100%	100%	0%
MS Circuit Breakers	Air Magnetic	41	41	0	0%	100%	100%	0%
	Bulk Oil	3	3	0	0%	100%	100%	0%
	Vacuum	7	7	0	0%	100%	100%	0%
MS Switchgear		22	21	-1	-5%	100%	100%	0%
Pole Top Transformers	Single Phase	2005	2003	-2	0%	72%	100%	28%
	Poly Phase	596	598	2	0%	72%	99%	27%
	Rabbit Type	43	43	0	0%	60%	100%	40%
Gang Operated Overhead Switches		146	132	-14	-10%	76%	78%	2%
Wood Poles		15369	15361	-8	0%	96%	100%	3%
Underground Cables *	XLPE Direct Buried	66.8	65.7	-1.1	-2%	68%	67%	-1%
	XLPE In Duct	183.2	179.9	-3.3	-2%	68%	68%	0%
	PILC	0.503	0.534	0.0	6%	100%	100%	0%
Pad Mounted Transformers	Single Phase	1262	1272	10	1%	100%	100%	0%
	Three Phase	281	281	0	0%	99%	99%	0%
Pad Mounted Switchgear		18	18	0	0%	100%	100%	0%

* by length (km)

Changes in Population

Figure 2 illustrates the changes in population.

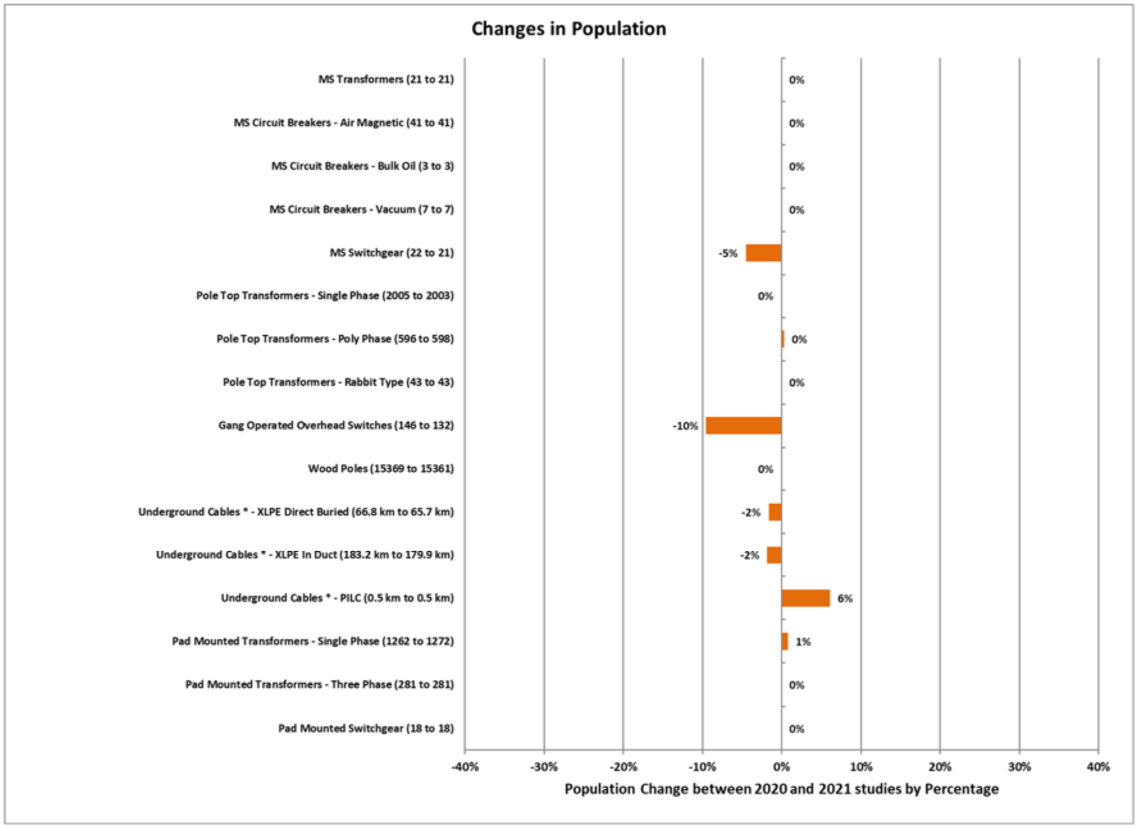

Figure 2 Changes in Population

The population of MS Transformers, MS Circuit Breakers and Pad Mounted Switchgear remained unchanged.

The MS Switchgear had the population decreased by 1 unit. Unit 32F1-B on Progress Drive was excluded in the inventory in 2020.

There was minor population size change for Pole Top Transformers: Single Phase units decreased by 2 while Poly Phase units increased by 2, with no change for Rabbit Type units.

The change in population for Gang Operated Overhead Switches was due to inventory database updating: 17 units were removed and 3 units were put in service. This resulted in the population decrease.

The length of PILC Cables showed an increase of 6%. This was however due to minor adjustment in inventory record and the total length was relatively small.

The population of the other asset groups remained relatively steady. The increase or decrease was marginal.

Changes in Sample Size

Figure 3 illustrates the changes in sample size.

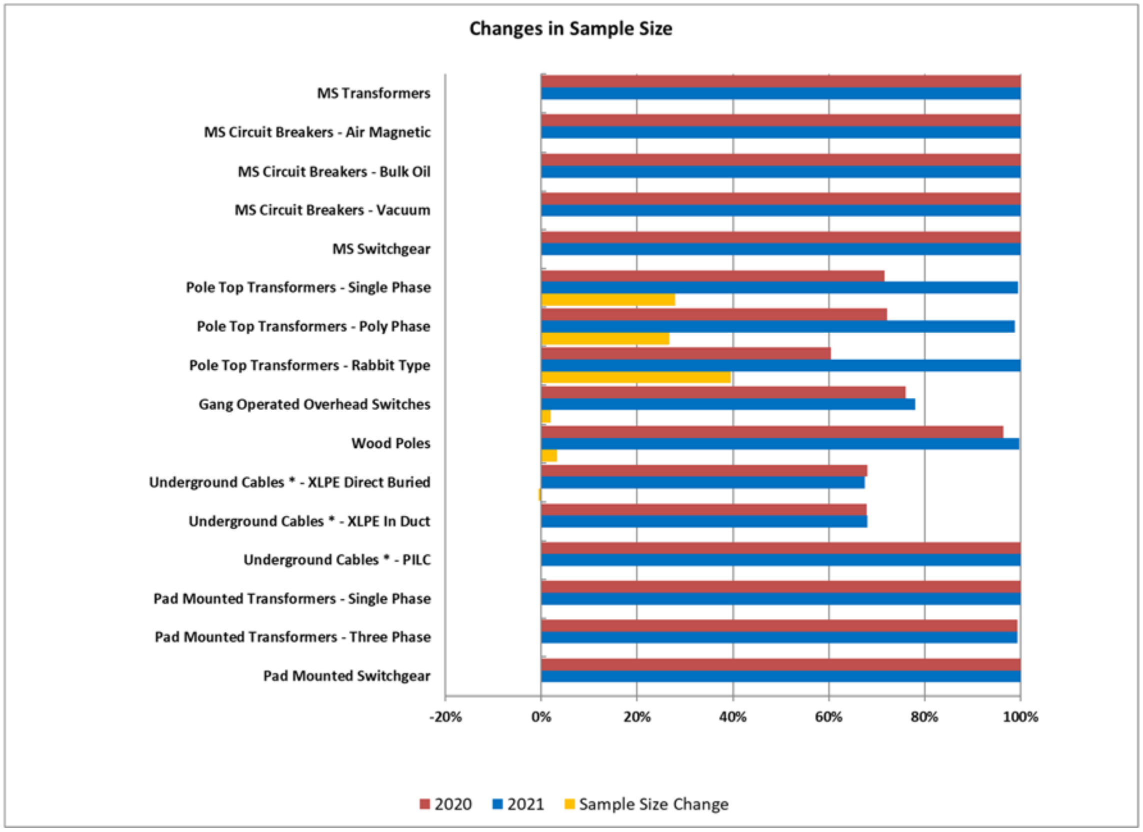

Figure 3 Changes in Sample Size

Ideally, condition data should be available for every asset within a population. Failing that, the larger the sample size, or subset of assets with sufficient condition information, the more confidence there is in extrapolating the ACA results over an entire asset population.

Pole Top Transformers had much improvement in terms of sample size, for all the 3 sub asset groups. For all the other asset groups, there was either no change in sample size, or the change was marginal.

--- Changes in Health Index Distribution

The changes in Health Index distribution between the 2020 and 2021 ACA studies are summarized in Table 5 and graphically shown in Figure 4.

The overall trend with respect to Health Index distribution was assessed. Assets that showed an increasing percentage of “good” and/or “very good” or a decrease of “very poor”, “poor”, and/or “fair” were classified as having overall improved health distributions. Conversely, asset classes with a decreasing percentage of “good” and/or “very good” or an increasing percentage of “very poor”, “poor”, and/or “fair” were classified as having an overall decline in health.

MS Transformers: The trend shows decline in overall condition. Units 32T1 and 20T2 had their conditions degraded and thus moved from “fair” in 2020 to “poor” and “very poor” respectively in 2021, mainly due to ageing. Similarly, units 11T1, 12T1 and 30T1 showed decline in their condition status due to ageing and thus moved from “very good” in 2020 to “good”, “good” and “fair” respectively in 2021. Meanwhile, unit 10T1 moved from “good” to “fair” in 2021 for the same reason.

MS Circuit Breakers Air Magnetic Type: The trend shows major decline in overall condition. This was mainly due to the revision on the HI formula, which ended up derating the aged units. All the ones previously rated “very good” in 2020 had their status moved to “good” or “fair” in 2021. Most of the units rated “good” in 2020 had their status moved to “fair”, except for the ones at station #13, which remained as “good” in 2021.

MS Circuit Breakers Bulk Oil Type: The trend shows major decline in overall condition. This was mainly due to the revision on the HI formula, which ended up derating the aged units. Due to the applied age limiting cap, the 2 units in “good” and 1 unit in “fair” in 2020 all had their status moved to “poor”, because of their very old physical ages.

MS Circuit Breakers Vacuum Type: The trend shows a minor improvement in overall condition. There was no change on HI category distribution. Unit UBEF4 at 21 Ube Drive had its status changed from “good” in 2020 to “very good” in 2021, as a result of inspection results change.

MS Switchgear: The trend shows minor change in overall condition. However, there were changes among different categories. The units categorized as “poor”, “good” and “very good” increased, while the ones categorized as “fair” decreased.

Pole Top Transformers Single Phase: The trend shows slight improvement in overall condition. There was a higher percentage of units classified as “good” or “very good” in 2021 than in 2020. Meanwhile the percentage of “very poor” also saw a slight increase. The percentages for units in “poor” or “fair” decreased.

Pole Top Transformers Poly Phase: The trend shows minor improvement in overall condition. The percentages of units classified as “very poor” or “very good” increased in 2021, while the percentages of the other 3 categories decreased.

Pole Top Transformers Rabbit Type: The trend shows little change in overall condition.

Gang Operated Overhead Switches: The trend shows little change in overall condition.

Wood Poles: The trend shows minor decrease in overall condition. This was mainly due to the aging degradation.

Underground Cables XLPE Direct Buried: The trend shows a decline in overall condition. The length of the cable in “very poor” condition increased by 5.5% in 2021 study. This was because some cable segments had their status degraded from “poor” in the 2020 study to “very poor” in 2021 study. The decline was attributed to aging, as the health indices were age driven.

Underground Cables XLPE in Duct: The trend shows little change in overall condition.

Underground Cables PILC in Duct: The trend shows no change in overall condition.

Pad Mounted Transformers 1-phase: The trend shows little change in overall condition.

Pad Mounted Transformers 3-phase: The trend shows minor decline in overall condition. Compared to 2020 study, in 2021 study there were fewer units classified as “very good” or “good”, while more units classified as “fair”, “poor” or “very poor”. This was due to inspection results updating and the introduction of age limiting factor in HI formula.

Pad Mounted Switchgear: The trend shows minor decline in overall condition. Compared to 2020 study, in 2021 study there were fewer units classified as “fair”, while more units classified as “poor” or “good”. This was due to inspection results updating and the introduction of age limiting factor in HI formula.

Table 5 Summary Change in Health Index Distribution

Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	%	Change
MS Transformers	2020	0.0%	4.8%	0.0%	4.8%	14.3%	0.0%	14.3%	4.8%	71.4%	-14.3%	86.5%	-6.1%
	2021	4.8%		4.8%		14.3%		19.0%		57.1%		80.3%	
MS Circuit Breakers - Air Magnetic	2020	0.0%	0.0%	0.0%	0.0%	0.0%	56.1%	22.0%	22.0%	78.0%	-78.0%	89.1%	-20.1%
	2021	0.0%		0.0%		56.1%		43.9%		0.0%		69.0%	
MS Circuit Breakers - Bulk Oil	2020	0.0%	0.0%	0.0%	100.0%	33.3%	-33.3%	66.7%	-66.7%	0.0%	0.0%	72.1%	-41.6%
	2021	0.0%		100.0%		0.0%		0.0%		0.0%		30.5%	
MS Circuit Breakers - Vacuum	2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.3%	-14.3%	85.7%	14.3%	91.3%	1.2%
	2021	0.0%		0.0%		0.0%		0.0%		100.0%		92.5%	
MS Switchgear	2020	0.0%	0.0%	36.4%	1.7%	40.9%	-2.8%	9.1%	0.4%	13.6%	0.6%	54.0%	0.6%
	2021	0.0%		38.1%		38.1%		9.5%		14.3%		54.7%	
Pole Top Transformers - Single Phase	2020	17.9%	0.9%	9.3%	-6.5%	4.6%	-1.7%	4.6%	0.6%	63.6%	6.8%	72.7%	4.3%
	2021	18.8%		2.8%		2.9%		5.2%		70.4%		77.1%	
Pole Top Transformers - Poly Phase	2020	7.9%	0.7%	4.2%	-2.0%	4.2%	-0.8%	5.6%	-2.4%	78.1%	4.4%	85.9%	1.7%
	2021	8.6%		2.2%		3.4%		3.2%		82.6%		87.5%	
Pole Top Transformers - Rabbit Type	2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	100.0%	-2.3%	98.3%	0.1%
	2021	0.0%		0.0%		0.0%		2.3%		97.7%		98.4%	
Gang Operated Overhead Switches	2020	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	1.8%	-1.8%	98.2%	0.8%	99.4%	-0.5%
	2021	1.0%		0.0%		0.0%		0.0%		99.0%		98.9%	
Wood Poles	2020	6.3%	1.2%	1.6%	-1.5%	4.4%	0.5%	78.0%	5.5%	9.6%	-5.7%	67.9%	-2.3%
	2021	7.5%		0.1%		4.9%		83.5%		3.9%		65.6%	
Underground Cables * - XLPE Direct Buried	2020	54.3%	5.5%	11.2%	-1.7%	6.1%	-4.1%	12.4%	1.3%	16.0%	-1.0%	35.9%	-3.9%
	2021	59.8%		9.5%		2.0%		13.6%		15.0%		32.0%	
Underground Cables * - XLPE In Duct	2020	1.4%	0.0%	1.6%	0.5%	0.7%	-0.7%	0.6%	0.0%	95.7%	0.2%	96.4%	0.2%
	2021	1.5%		2.1%		0.0%		0.6%		95.8%		96.6%	
Underground Cables * - PILC	2020	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2021	100.0%		0.0%		0.0%		0.0%		0.0%		0.0%	
Pad Mounted Transformers - Single Phase	2020	0.0%	0.8%	0.2%	0.4%	1.0%	1.5%	5.2%	0.7%	93.7%	-3.3%	96.1%	-0.8%
	2021	0.8%		0.6%		2.4%		5.9%		90.3%		95.2%	
Pad Mounted Transformers - Three Phase	2020	0.0%	0.4%	1.1%	0.4%	1.4%	7.2%	15.8%	-7.5%	81.7%	-0.4%	94.2%	-1.7%
	2021	0.4%		1.4%		8.6%		8.2%		81.4%		92.5%	
Pad Mounted Switchgear	2020	0.0%	0.0%	0.0%	5.6%	27.8%	-16.7%	0.0%	11.1%	72.2%	0.0%	89.5%	-1.6%
	2021	0.0%		5.6%		11.1%		11.1%		72.2%		87.9%	

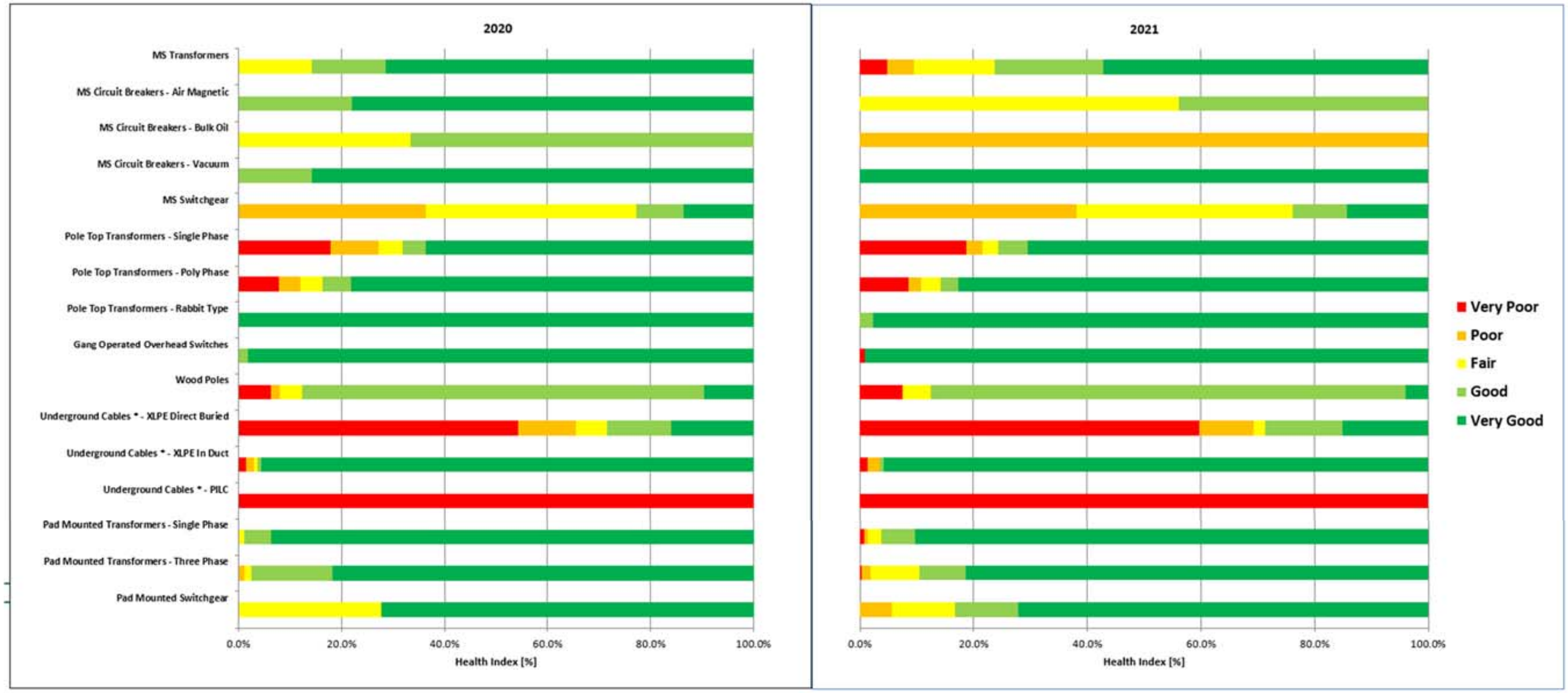

Figure 4 Changes in Health Index

Conclusions and Recommendations

1. An Asset Condition Assessment was conducted for nine of BWP's key distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged-for-Action plan was developed.

2. Asset categories of concern were Direct Buried XLPE Underground Cables, PILC Underground Cables, Bulk Oil MS Circuit Breakers, MS Switchgear and Single Phase Pole Mounted Transformers. For these asset categories, the percentages of assets in "poor" or "very poor" condition were 69%, 100%, 100%, 38% and 22% of the population respectively.

3. MS Switchgear, Single Phase Pole Mounted Transformers, Wood Poles, XLPE Direct Buried and PILC Underground Cables, and Pad Mounted Switchgear were determined to have the highest flagged for action percentage among all the asset groups: within 10 years about 67%, 26%, 56%, 92%, 100% and 21% of the population should be addressed respectively.

4. Other asset categories of concern in the sense of flagged-for-action plan included Poly Phase Pole Top Transformers: during the 10-year period starting from now, there were 15% of units flagged for action.

5. In general, Vacuum Type MS Breakers and Rabbit Type Pole Top Transformers were in good shape: all the units were classified as "good" or "very good".

6. For each asset category it is recommended that the data gaps be addressed in order of the priority given in this report.

7. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study.

8. BWP is advised to re-check the inventory list on a yearly basis to ensure all the available information be included.

It is important to note that the Flagged-for-Action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence BWP's Asset Management Plan, such as obsolescence, system growth, regulatory requirements, municipal initiatives, etc.

Based on the available data, the Wood Poles population seems to be in an overall good condition. However, there are concerns with the "good" classification in the data. The available inspection data collected for wood poles is typically based on an overall (full pole assembly) inspection, rather than solely the wood pole. In addition, the age of poles is only available for about 46% of the population, and pole test data was not adequate to identify the condition of the poles based on their remaining strength. The most reliable data for BWP indicates that of the approximately 4740 wood poles BWP tested for cavity and decay, a failure rate of approximate 8% was found for such a subset of the entire population.

Based on current test results, it is expected that the anticipated annual replacement numbers will support the quantity listed for first year replacement in Table 2 Condition-Based Short-Term Flagged-for-Action Plan. It is recommended that BWP continue testing and further develop their wood pole testing program for any wood poles greater than 20 years old and continue to gather, estimate and confirm to the extent possible ages of all the poles.

It is recommended that BWP improve updating the detailed vault inspection data for Pad Mounted Switchgear, so that the up-to-date inspection results could be used for health indexing.

It is recommended that BWP continue to collect failure statistics so that BWP-specific failure models can be developed and used in future assessments. The failure statistics information to be collected includes the following data:

- The ID of the unit that failed (here failed means removed out of service for good)
- The age at the time the above unit failed

It is noted that BWP has started such data collection for distribution transformers and underground cables. It is recommended that such practice be extended to all asset classes.

APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

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1. MS TRANSFORMERS

1.1. Health Index Formula of MS Transformers

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

1.1.1. Condition and Sub-Condition Parameters

Table 1-1 MS Transformers Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Insulation	6	Table 1-2
2	Cooling	1	Table 1-3
3	Sealing & Connection	3	Table 1-4
4	Service Record	3	Table 1-5
	Age limiter*		Figure 1-1

* Age limiter sets the maximum HI a unit can reach based on its age

Table 1-2 Insulation Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Quality	1	Table 1-6
2	Oil DGA	2	Table 1-7
3	Winding Dissipation	1	Table 1-8
4	Furan	1	Table 1-9

Table 1-3 Cooling Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Operation of Cooling Fans	1	Table 1-11

Table 1-4 Sealing & Connection Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Paint Condition	1	Table 1-11
2	Oil Levels	2	Table 1-11
3	Oil Leaks & External Damage to Rads	5	Table 1-11
4	Primary/Secondary/Ground Connection	2	Table 1-11
5	Clean & Inspect Bushings, Clamps, Gaskets	1	Table 1-11
6	Breather/Silica/Other	2	Table 1-11

Table 1-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Loading	5	Table 1-12

1.1.2. Condition Criteria

Oil Quality

The “Oil Quality” parameter is a composite of the following oil properties: moisture, dielectric strength, interfacial tension, color, and acidity.

Table 1-6 Oil Quality Test Criteria

Score	Description
4	Overall Factor is less than 1.2
3	Overall Factor between 1.2 and 1.5
2	Overall Factor is between 1.5 and 2.0
1	Overall Factor is between 2.0 and 3.0
0	Overall Factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	4
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5

* Select the row applicable to the equipment rating

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Oil DGA

Table 1-7 Transformer DGA Criteria

Score	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

Dissolved Gas	**Scores**						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Winding Dissipation Factor Test

Table 1-8 Winding Dissipation Factor Test Criteria

Score	Description
4	dissipation factor reading $\le$ 0.3%
3	0.3% < dissipation factor reading $\le$ 0.5%
2	0.5% < dissipation factor reading $\le$ 0.7%
1	0.7% < dissipation factor reading $\le$ 1.0%

0	dissipation factor reading > 1.0%

Furan Test

Table 1-9 Furan Test Criteria

Score	Description	
	2Fal reading (ppb)	Qualitative assessment
4	0	Sample in 3 years
3	100	Sample annually
2	200	Sample in 6 months
1	600	
0	1000	
If 2-Fal reading is available, the 2-Fal criteria will be used; otherwise, the qualitative assessment criteria is adopted		

Age

In the case of MS Transformers, age was used as a limiting factor to reflect the degradation of asset unit as time passed by.

The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution.

$$Age\_Limiting = S_f = e^{-(\frac{x}{\alpha})^{\beta}}$$

Equation 1-1

S_f = survivor function
x = age in years
α = *constant that controls scale of function*
β = *constant that controls shape of function*

Assuming that at the ages of 50 and 80 years the probability of failures (P_f) for MS Transformers are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 1-1.

Table 1-10 Age Limiting Curve Parameters - MS Transformers

Asset Type	α	β
MS Transformers	**65.6**	**5.53**

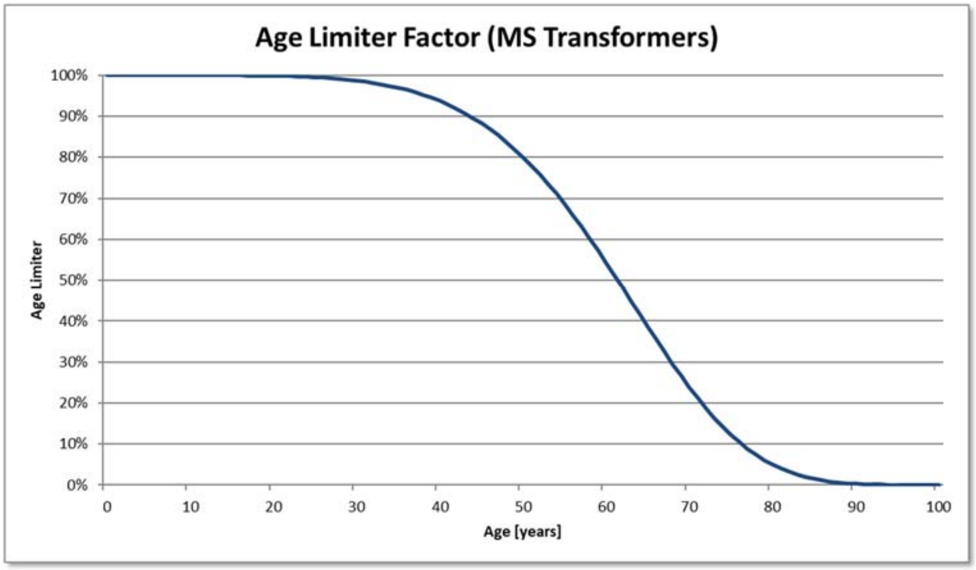

Figure 1-1 MS Transformers Age Limiter Criteria

Station Inspections

Table 1-11 Inspection Condition Criteria

CPF	Description
4	0
3	1
2	2
1	3
0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score			Weight
	0	2	4	
2020	Good / None	Fair	Any defect intervention	1
2019				0.9
2018				0.8
2017				0.7
2016				0.6
2015				0.5
2014				0.4
2013				0.3
2012				0.2
2011				0.1

Inspection count = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight_i}$

Where i refers to the year the inspection was conducted

Loading History

Table 1-12 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)

SB= rated MVA

NA=Number of Si/SB which is lower than 0.6
NB= Number of Si/SB which is between 0.6 and 0.8
NC= Number of Si/SB which is between 0.8 and 1.0
ND= Number of Si/SB which is between 1 and 1.2
NE= Number of Si/SB which is greater than 1.2

Score = $\dfrac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$

Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

1.2. Age Distribution of MS Transformers

The average age of all in service units was 35. The age distribution for in service MS Transformers was as follows.

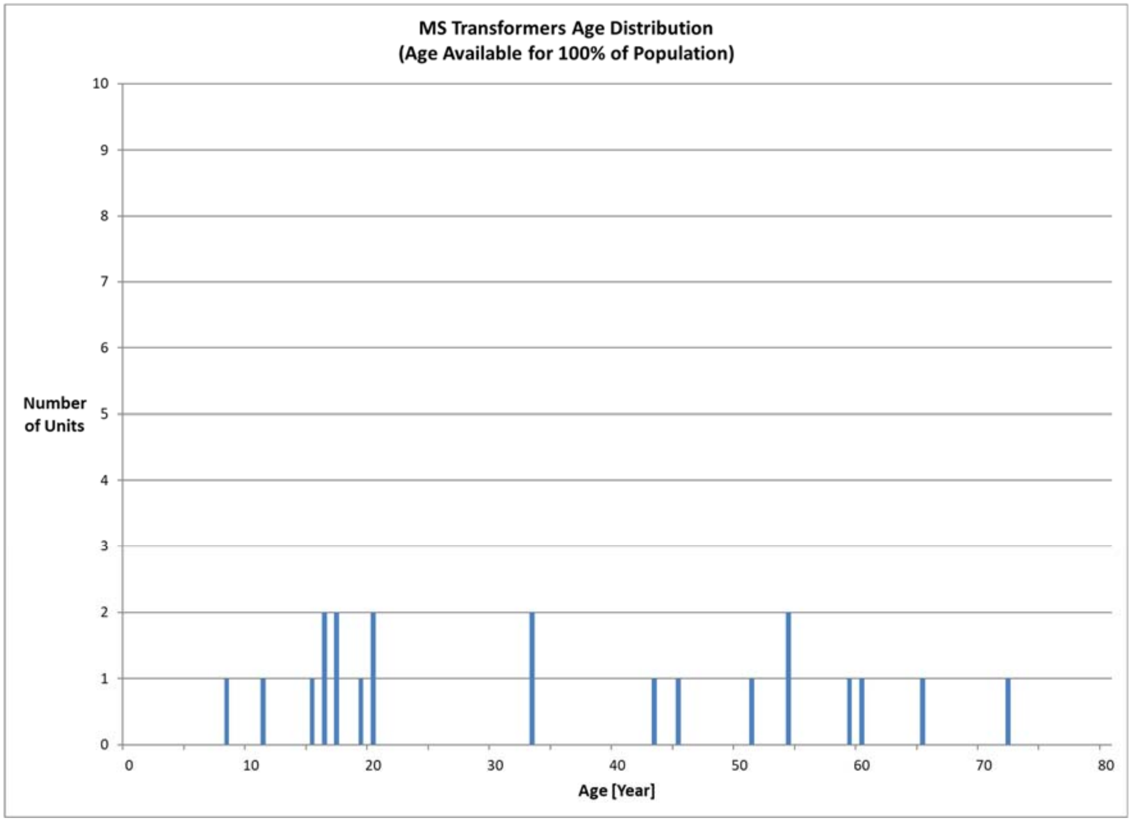

Figure 1-2 MS Transformers Age Distribution

1.3. Health Index Results of MS Transformers

There were 21 in service MS Transformers at BWP. All of them had sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units were shown:

The average Health Index for this asset group was 80%. Two of the units were found to be in “poor” or “very poor” condition.

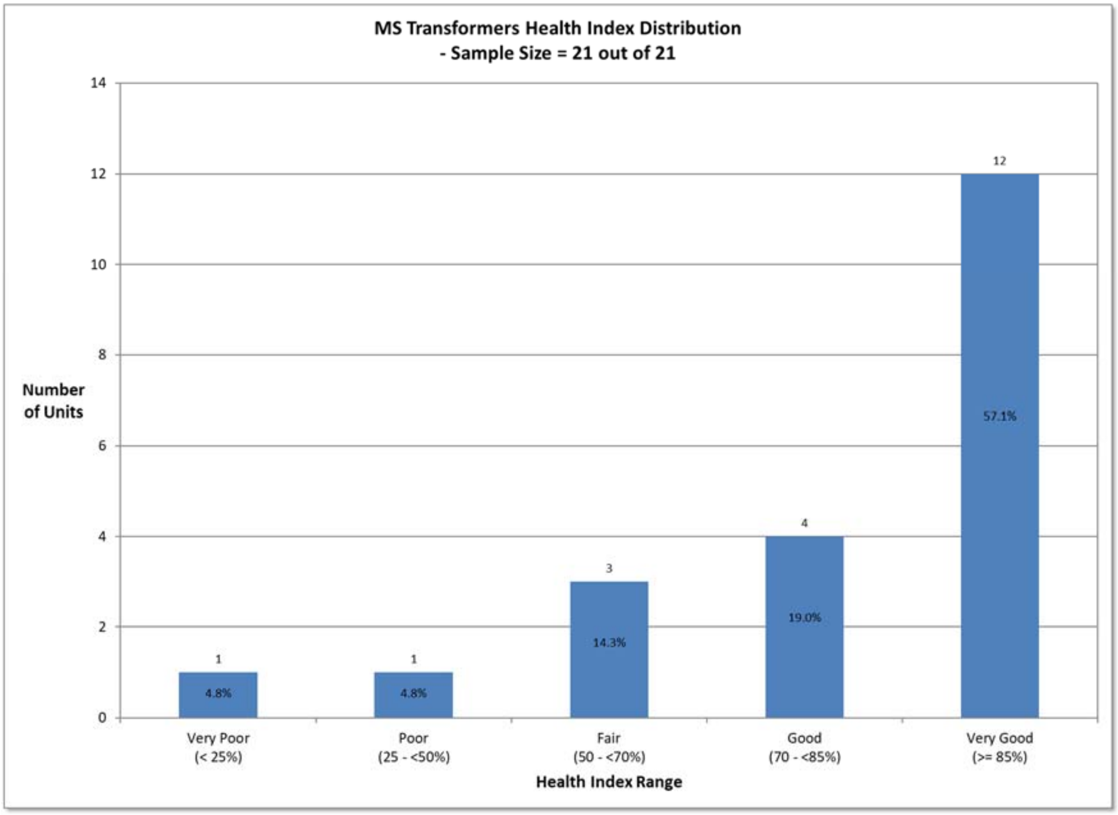

Figure 1-3 MS Transformers Health Index Distribution

1.4. Risk-Based Flagged-for-Action Plan of MS Transformers

It is assumed that MS Transformers are proactively replaced. The risk of a unit failure is equal to the product of its probability of failure and criticality. A unit becomes a candidate for replacement when its risk is greater than or equal to one.

Each unit's criticality is defined as follows:

$$\text{Criticality} = (\text{Criticality}_{max} - \text{Criticality}_{min})*\text{Criticality\_Multiple} + \text{Criticality}_{min}$$

where:

Criticality_{max} = 1/(80%) = 1.25 (the units with highest relative importance should be replaced when their POF reaches 80%)

Criticality_{min} = 1/(95%) = 1.0526 (the units with lowest relative importance can wait until their POF reaches 95% to be replaced)

$$Criticality\_Multiple = \frac{\sum_{CF=1}^{\forall CF}(CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF}(WCF_{CF})}$$

The factors, weights and the score system of each factor are as follows:

Table 1-13 MS Transformers Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load criticality	--- Number of customers --- Customer importance (e.g. hospitals, provincial buildings, restoration time sensitive customers)	30	Low	0
			High	1
Physical Protection	oil containment, blast wall, deluge system	15	Yes	0
			No	1
Location	public exposure, environmental impact	15	No	0
			Yes	1
Expected Outage Duration	Back-up unit unavailable, alternate feeds unavailable	20	No	0
			Yes	1
Operation & Maintenance	--- obsolescence of spare parts (e.g. manufacturers cease to produce old types of spare parts) --- known issues (e.g. not economical to have routine maintenance)	20	No	0
			Yes	1

The table below shows examples of criticalities for three separate units.

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Number of Customers	Low	0	0	High	1	25	High	1	25
Oil Containment	Yes	0	0	No	1	10	No	1	10
Location (near water creeks)	No	0	0	No	0	0	Yes	1	50
Transformer Primary Protection	Breaker	0	0	Breaker	0	0	Fuse	1	15
	Criticality Multiple		0	Criticality Multiple		0.35	Criticality Multiple		1
	Criticality		(1.25-1.0526) *0 + 1.0526 = **1.0526**	**Criticality**		(1.25-1.0526) *0.35 + 1.0526 = **1.1217**	**Criticality**		(1.25-1.0526)*1 + 1.0526 =**1.25**

As previously noted a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. The flagged-for-action plan for in service MS Transformers was as follows:

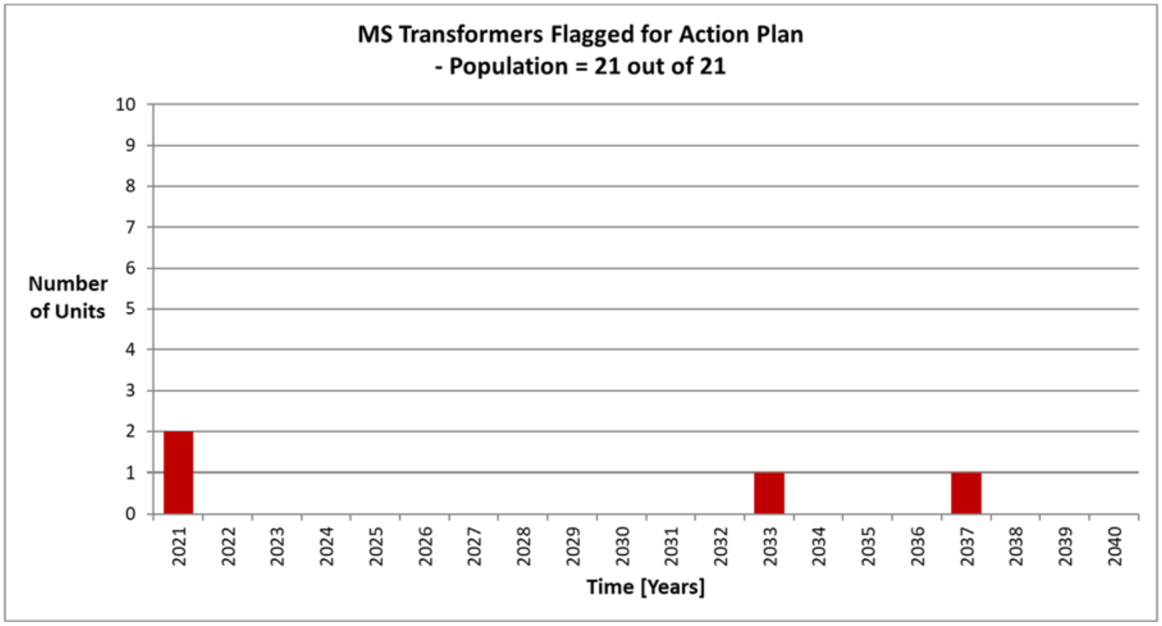

Figure 1-4 MS Transformers Risk-Based Flagged-for-Action Plan

The reason for the 2 units flagged for action in the first year was because of the ageing limiter introduced in this year's ACA study. Although both units showed good condition status as per inspection and test results, their HI results were capped by the age limiting curve due to their old ages, being 65 and 72 respectively. This means that utility needs to have a review on these units to ensure there is no defect that was not captured by routine inspection and test.

1.5. Risk-Based Prioritization List of MS Transformers

The following table shows the risk based prioritization list for MS Transformers.

Table 1-14 Risk-Based Prioritization List of MS Transformers

Rank	Unique ID	Address	Age	Health Index	Probability of Failure	Criticality Percentage	Action Year From Now
1	32T1	[redacted]	65	34.8%	97.4%	45%	0
2	20T2	[redacted]	72	18.8%	99.0%	0%	0
3	30T1	[redacted]	60	54.3%	57.9%	45%	12
4	10T1	[redacted]	59	57.3%	48.0%	30%	16
5	14T1	[redacted]	43	69.2%	13.6%	45%	>20
6	11T1	[redacted]	54	71.1%	10.6%	30%	>20
7	12T1	[redacted]	54	71.1%	10.6%	30%	>20
8	13T1	[redacted]	51	78.0%	3.6%	30%	>20
9	46T1	[redacted]	11	80.5%	2.0%	60%	>20
10	9T1	[redacted]	45	88.3%	0.3%	30%	>20
11	UBET1	[redacted]	20	90.0%	0.2%	15%	>20
12	UBETR14	[redacted]	20	90.0%	0.2%	15%	>20
13	1T2	[redacted]	33	96.2%	0.0%	30%	>20
14	31T1	[redacted]	16	98.1%	0.0%	60%	>20
15	46T2	[redacted]	15	100.0%	0.0%	60%	>20
16	7T1	[redacted]	19	97.2%	0.0%	30%	>20
17	1T1	[redacted]	33	97.8%	0.0%	30%	>20
18	3T1	[redacted]	17	98.1%	0.0%	30%	>20
19	8T1	[redacted]	17	98.1%	0.0%	30%	>20
20	5T1	[redacted]	16	98.1%	0.0%	30%	>20
21	21T1	[redacted]	8	100.0%	0.0%	15%	>20

1.6. Data Assessment of MS Transformers

The data for in service MS Transformers included inspection results, loading, age, oil quality, Furan, dissolved gas analysis, and winding dissipation factor tests.

Data Availability Indicator

The average DAI of this group was 80%. The data availability distribution for the entire population was as follows:

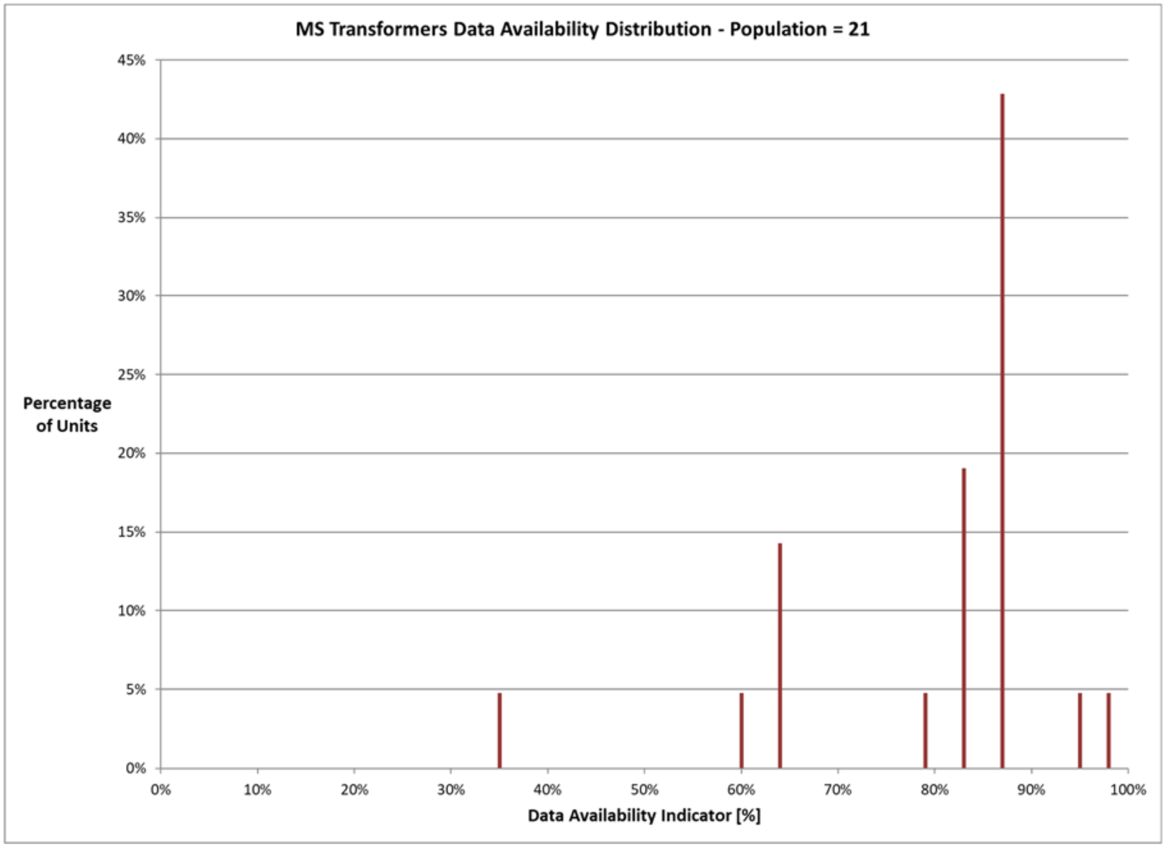

Figure 1-5 MS Transformers Data Availability Distribution

Data Gap

The data gaps included inspection on transformer temperature/cooling. The inspection for these conditions was conducted at substation level, not at unit level, thus making it impossible to know the condition status of a specific unit.

Table 1-15 Data Gap for MS Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Transformer Temperature	Cooling	☆ ☆	Transformer oil and winding	Temperature beyond limit	Visual inspection

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2. MS CIRCUIT BREAKERS

2.1. Health Index Formula of MS Circuit Breakers

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

2.1.1. Condition and Sub-Condition Parameters

Table 2-1 MS Circuit Breakers Condition Parameter and Weights

m	Condition parameter	WCP_m			CPS Lookup Table
		Oil	Vacuum	Air	
1	Operating mechanism	14	7	14	Table 2-2
2	Contact performance	7	7	7	Table 2-3
3	Arc extinction	9	5	5	Table 2-4
4	Insulation	2	2	2	Table 2-5
5	Service Record	5	5	5	Table 2-6
	Age limiter*				Figure 2-1

* Age limiter sets the maximum HI a unit can reach based on its age

Table 2-2 Operating Mechanism Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Mech Interlock	2	Table 2-7
2	Interlock	1	Table 2-7
3	Racking Mechanism	1	Table 2-7

Table 2-3 Contact Performance Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Contacts Condition	1	Table 2-7
2	Contact Resistance	2	Table 2-9
3	Manual Trip	1	Table 2-7
4	Manual Close	1	Table 2-7
5	Electrical Trip	3	Table 2-7
6	Electrical Close	2	Table 2-7

Table 2-4 Arc Extinction Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Arc Chute	1	Table 2-7

Table 2-5 Insulation Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Insulation Resistance	1	Table 2-11

Table 2-6 Service Record Sub-Condition Parameters and Weights (m=5)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Comments	2	Table 2-8
2	Operating Counter	5	Table 2-12

2.1.2. *Condition Criteria*

Station Inspections

Table 2-7 Inspection Condition Criteria

CPF	Description
4	0
3	1
2	2
1	3
0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score			Weight
	0	2	4	
2020	Good / None	OK	Any defect intervention	1
2019				0.9
2018				0.8
2017				0.7
2016				0.6
2015				0.5
2014				0.4
2013				0.3
2012				0.2
2011				0.1

Inspection count = $$\frac{\sum Score_i \times Weight_i}{\sum Weight_i}$$

Where i refers to the year the inspection was conducted

Overall Station Inspection

Table 2-8 Comment Condition Criteria

CPF	**Description (Overall count)**
4	0
3	1
2	2
1	3
0	4

Where overall count is calculated based on detection of specific defects as below:

	Score					**Weight**
Year	0	1	2	3	4	
2020	Good	Fit	Pass	Defect	Replace	1
2019						0.9
2018						0.8
2017						0.7
2016						0.6
2015						0.5
2014						0.4
2013						0.3
2012						0.2
2011						0.1

$$\text{Inspection count} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Where i refers to the year the inspection was conducted

Measurement

Breaker timing and contact resistance measurements indicate the proper function of the breaker as designed. It is crucial that the breaker meets these specifications for proper and reliable operation.

Table 2-9 Resistance Test Criteria

Score	Condition Description
4	Measurement <= 80% Specification limit
3	Measurement (80%, 100%] specification limit
1	Measurement (100%, 120%] specification limit
0	Measurement > 120% specification limit

Where specification limit is defined in the following table

Table 2-10 Contact Resistance Specification Limit

CB type	<= 69 kV
Oil	300 U OHM
Vacuum & Air Magnet	250 U OHM

Table 2-11 Insulation Resistance Condition Criteria

Condition Rating	CPF	Description
PASS	4	>= 1000 MOhm
FAIL	0	< 1000 MOhm

Table 2-12 Operating Counter Criteria

Score	Condition Description
4	Counter reading <= 80% Maximum design operation limit
3	Counter reading (80%, 100%] Maximum design operation limit
1	Counter reading (100%, 120%] Maximum design operation limit
0	Counter reading > 120% Maximum design operation limit

Age

In the case of MS Circuit Breakers, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 55 and 85 years the probability of failures (P_f) for MS Circuit Breakers are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 2-1.

Table 2-13 Age Limiting Curve Parameters - MS Circuit Breakers

Asset Type	α	β
MS Circuit Breakers	**71.84**	**5.82**

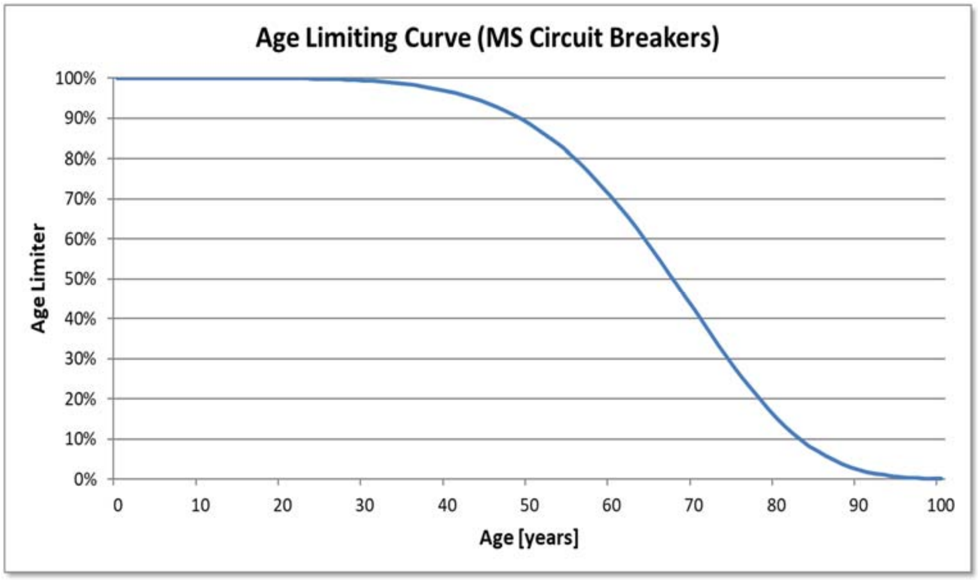

Figure 2-1 MS Circuit Breakers Age Limiter Criteria

2.2. Age Distribution MS Circuit Breakers

The age distribution for this asset class was shown on the figure below. The average age of the population was 60, 74 and 19 years old, for air magnetic, bulk oil and vacuum circuit breakers respectively.

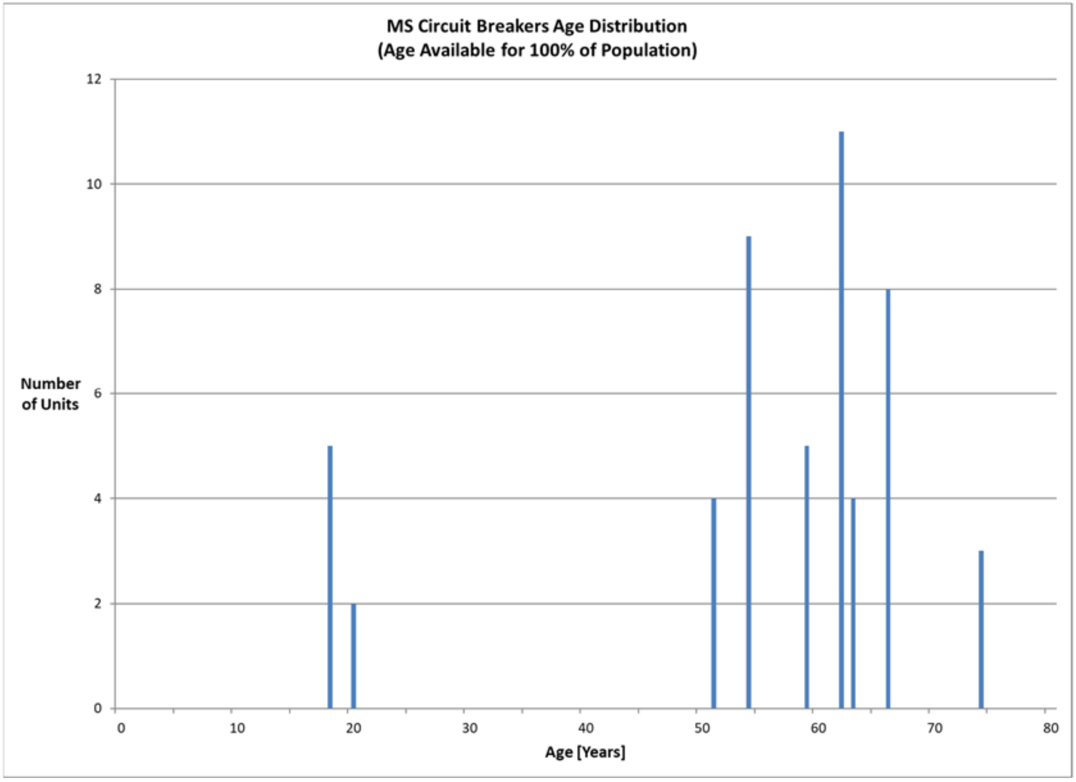

Figure 2-2 Circuit Breakers Age Distribution

2.3. Health Index Results MS Circuit Breakers

There were 51 MS Circuit Breakers at BWP. All of them had sufficient data for a Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units were shown in the following diagrams for different types.

Air Magnetic Circuit Breakers

In total there were 41 units of this circuit breaker type. The average Health Index for this asset type was 69%. None of the population was found to be in "poor" or "very poor" condition.

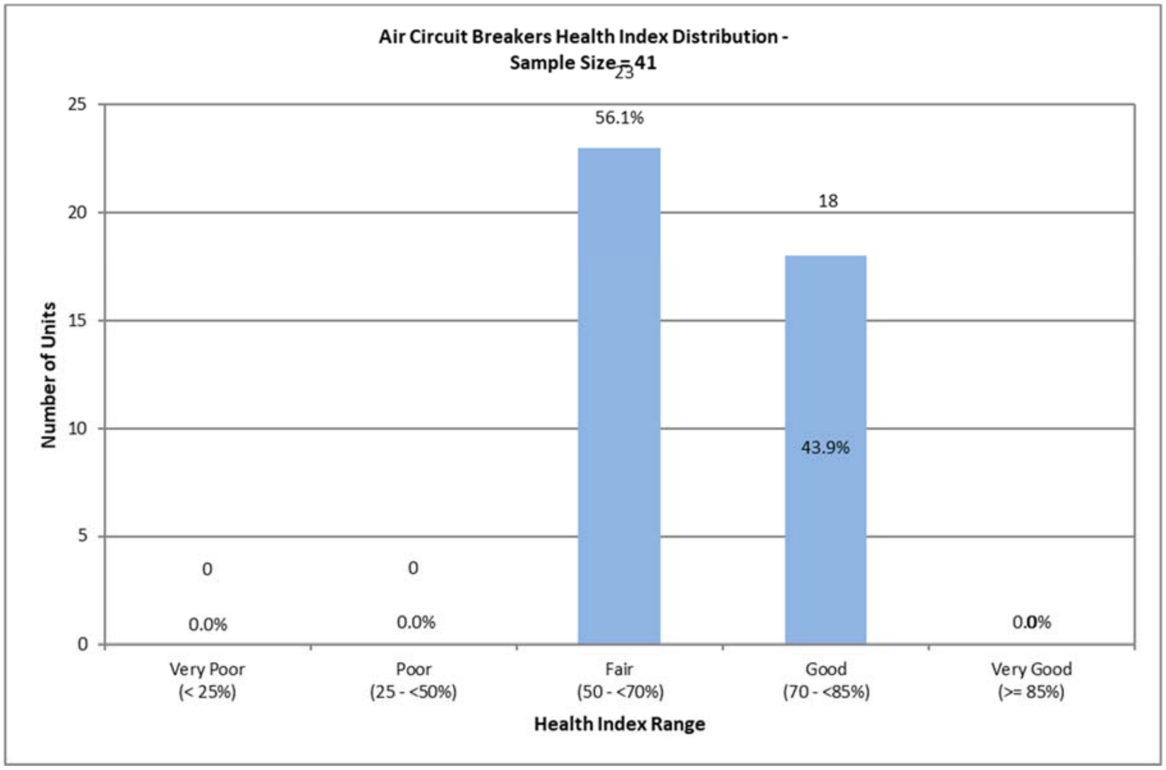

Figure 2-3 Circuit Breakers Health Index Distribution (Air Magnetic Type)

Bulk Oil Circuit Breakers

In total there were 3 units of this circuit breaker type. The average Health Index for this asset type was 30%. All were found to be in “poor” condition.

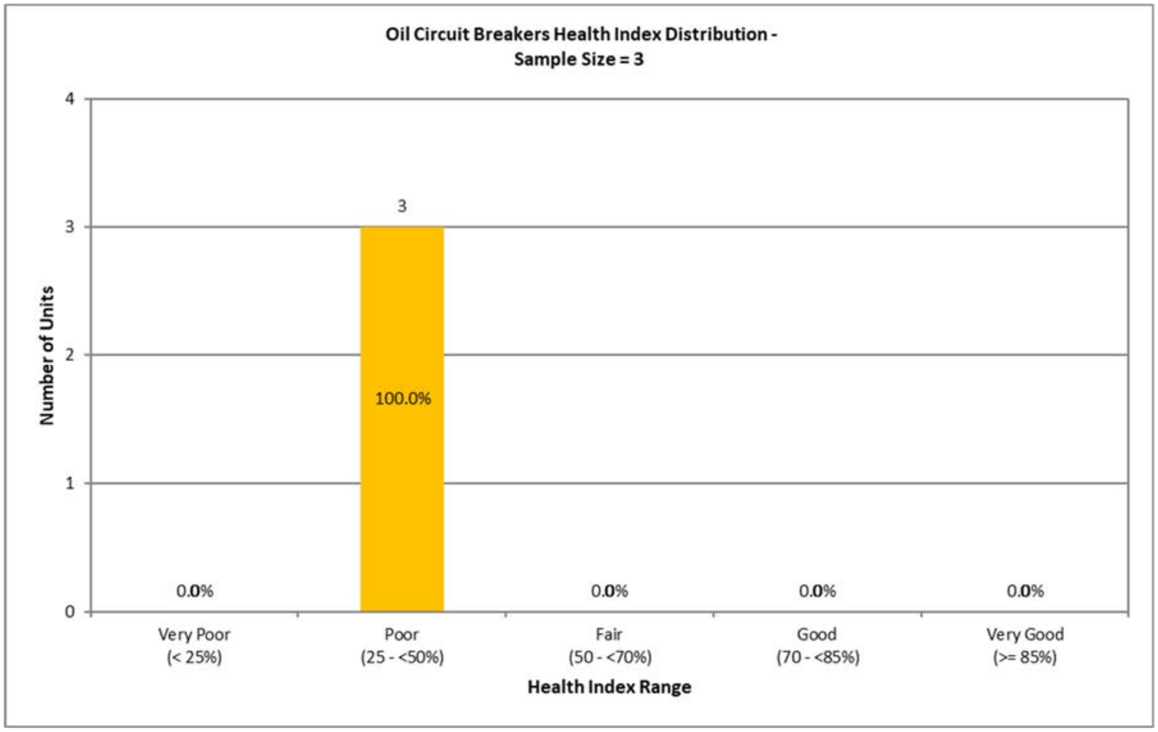

Figure 2-4 Circuit Breakers Health Index Distribution (Bulk Oil Type)

Vacuum Circuit Breakers

In total there were 7 units of this circuit breaker type. The average Health Index for this asset type was 92%. All the population was found to be in "very good" condition.

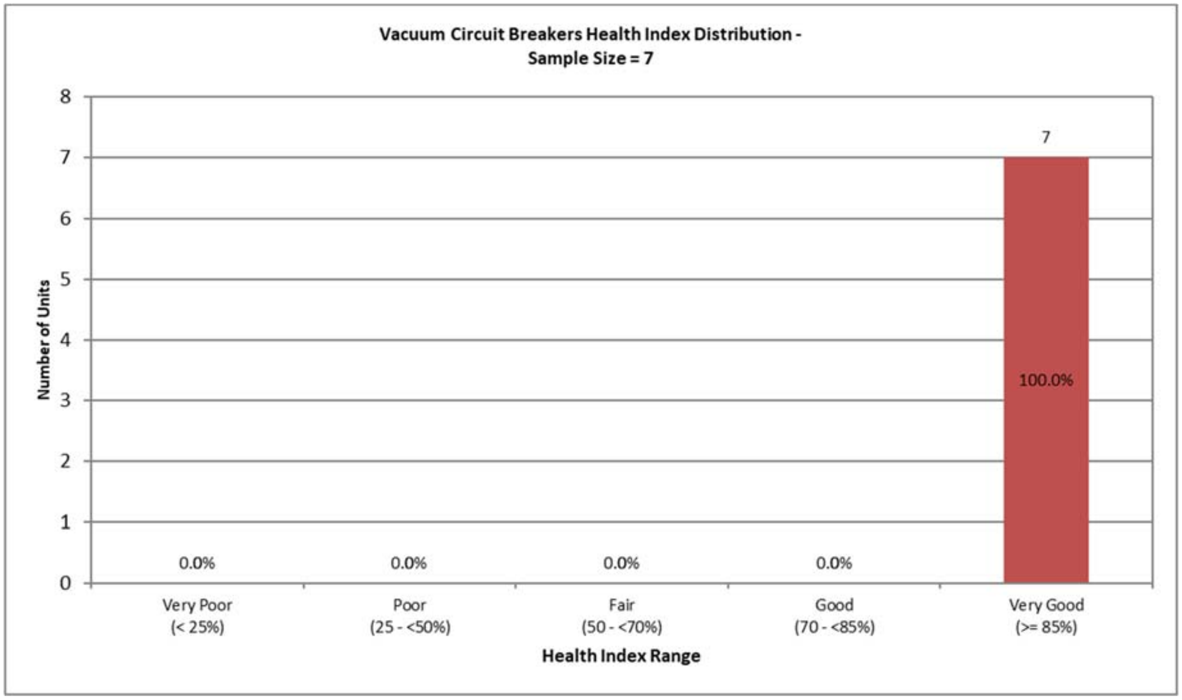

Figure 2-5 Circuit Breakers Health Index Distribution (Vacuum Type)

2.4. Condition-Based Flagged-for-Action Plan of MS Circuit Breakers

It is assumed that MS Circuit Breakers were proactively replaced. The risk of a unit failure is equal to the product of its probability of failure and criticality. A unit becomes a candidate for replacement when its risk is greater than or equal to one.

As in this study, all MS Circuit Breakers were assumed to have equal criticalities of 1.25, the flagged-for-action plan became condition-based. In such a case, a unit with a probability of failure of 80% became a candidate for action.

The flagged-for-action plan for MS Circuit Breakers was given below:

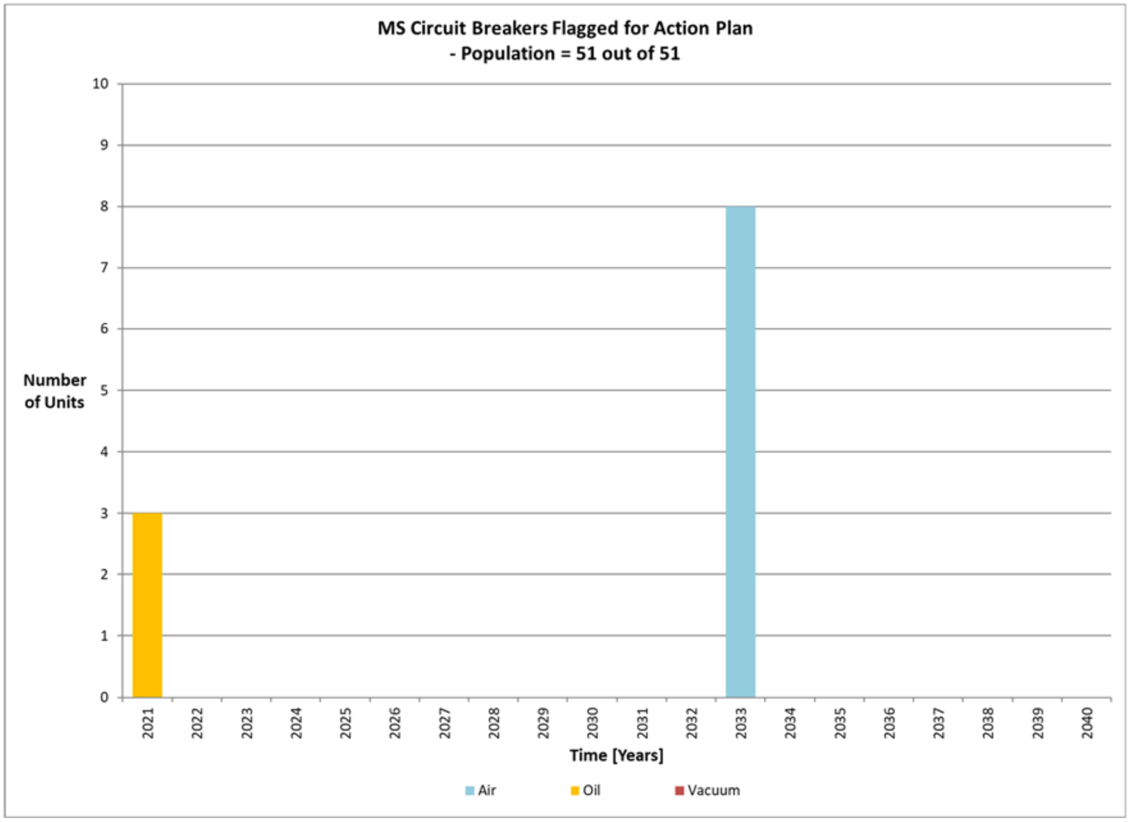

Figure 2-6 Circuit Breakers Condition-Based Flagged-for-Action Plan

2.5. Condition-Based Prioritization List of MS Circuit Breakers

The following table shows the condition-based prioritization list for MS Circuit Breakers.

Table 2-14 Condition-Based Prioritization List of MS Circuit Breakers

Rank	Unique ID	Type Code	Address	Age	Health Index	Probability of Failure	Action Year From Now
1	30F1	OCB	[redacted]	74	30.5%	>90%	0
2	30F2	OCB	[redacted]	74	30.5%	>90%	0
3	30F3	OCB	[redacted]	74	30.5%	>90%	0
4	1F7	ACB	[redacted]	66	54.3%	48.0%	12
5	1T1-BK	ACB	[redacted]	66	54.3%	48.0%	12
6	1F1	ACB	[redacted]	66	54.3%	48.0%	12
7	1F2	ACB	[redacted]	66	54.3%	48.0%	12
8	1F3	ACB	[redacted]	66	54.3%	48.0%	12
9	1F8	ACB	[redacted]	66	54.3%	48.0%	12
10	1T2-BK	ACB	[redacted]	66	54.3%	48.0%	12
11	1F9	ACB	[redacted]	66	54.3%	48.0%	12
12	7F1	ACB	[redacted]	63	62.8%	24.2%	>20
13	7F3	ACB	[redacted]	63	62.8%	24.2%	>20
14	7F2	ACB	[redacted]	63	62.8%	24.2%	>20
15	7T1	ACB	[redacted]	63	62.8%	24.2%	>20
16	8F2	ACB	[redacted]	62	65.4%	17.1%	>20
17	9F1	ACB	[redacted]	62	65.4%	17.1%	>20
18	9F3	ACB	[redacted]	62	65.4%	17.1%	>20
19	9F4	ACB	[redacted]	62	65.4%	17.1%	>20
20	9T1	ACB	[redacted]	62	65.4%	17.1%	>20
21	8F1	ACB	[redacted]	62	65.4%	17.1%	>20
22	8F3	ACB	[redacted]	62	65.4%	17.1%	>20
23	8T1	ACB	[redacted]	62	65.4%	17.1%	>20
24	8F4	ACB	[redacted]	62	65.4%	17.1%	>20
25	8F5	ACB	[redacted]	62	65.4%	17.1%	>20
26	9F2	ACB	[redacted]	62	65.4%	17.1%	>20
27	10T1	ACB	[redacted]	59	72.8%	6.7%	>20
28	10F2	ACB	[redacted]	59	72.8%	6.7%	>20
29	10F3	ACB	[redacted]	59	72.8%	6.7%	>20
30	10F4	ACB	[redacted]	59	72.8%	6.7%	>20
31	10F1	ACB	[redacted]	59	72.8%	6.7%	>20
32	13F2	ACB	[redacted]	51	78.8%	2.3%	>20
33	13F1	ACB	[redacted]	51	78.8%	2.3%	>20
34	13F3	ACB	[redacted]	51	78.8%	2.3%	>20
35	13T1	ACB	[redacted]	51	78.8%	2.3%	>20
36	11F2	ACB	[redacted]	54	82.7%	1.1%	>20
37	11F3	ACB	[redacted]	54	82.7%	1.1%	>20
38	11T1	ACB	[redacted]	54	82.7%	1.1%	>20
39	12F1	ACB	[redacted]	54	82.7%	1.1%	>20
40	12F2	ACB	[redacted]	54	82.7%	1.1%	>20
41	12F3	ACB	[redacted]	54	82.7%	1.1%	>20
42	12F4	ACB	[redacted]	54	82.7%	1.1%	>20
43	12T1	ACB	[redacted]	54	82.7%	1.1%	>20
44	11F1	ACB	[redacted]	54	82.7%	1.1%	>20
45	3F1	VCB	[redacted]	18	86.8%	0.4%	>20
46	3F2	VCB	[redacted]	18	86.8%	0.4%	>20
47	3F3	VCB	[redacted]	18	86.8%	0.4%	>20
48	3F4	VCB	[redacted]	18	86.8%	0.4%	>20
49	UBEF4	VCB	[redacted]	20	99.9%	0.0%	>20
50	T1A	VCB	[redacted]	20	99.9%	0.0%	>20
51	3T1-B	VCB	[redacted]	18	100.0%	0.0%	>20

2.6. Data Analysis of MS Circuit Breakers

The data available for this asset category included age, contact resistance, and inspection results.

Data Availability Indicator

The data availability distribution for the entire population was as follows:

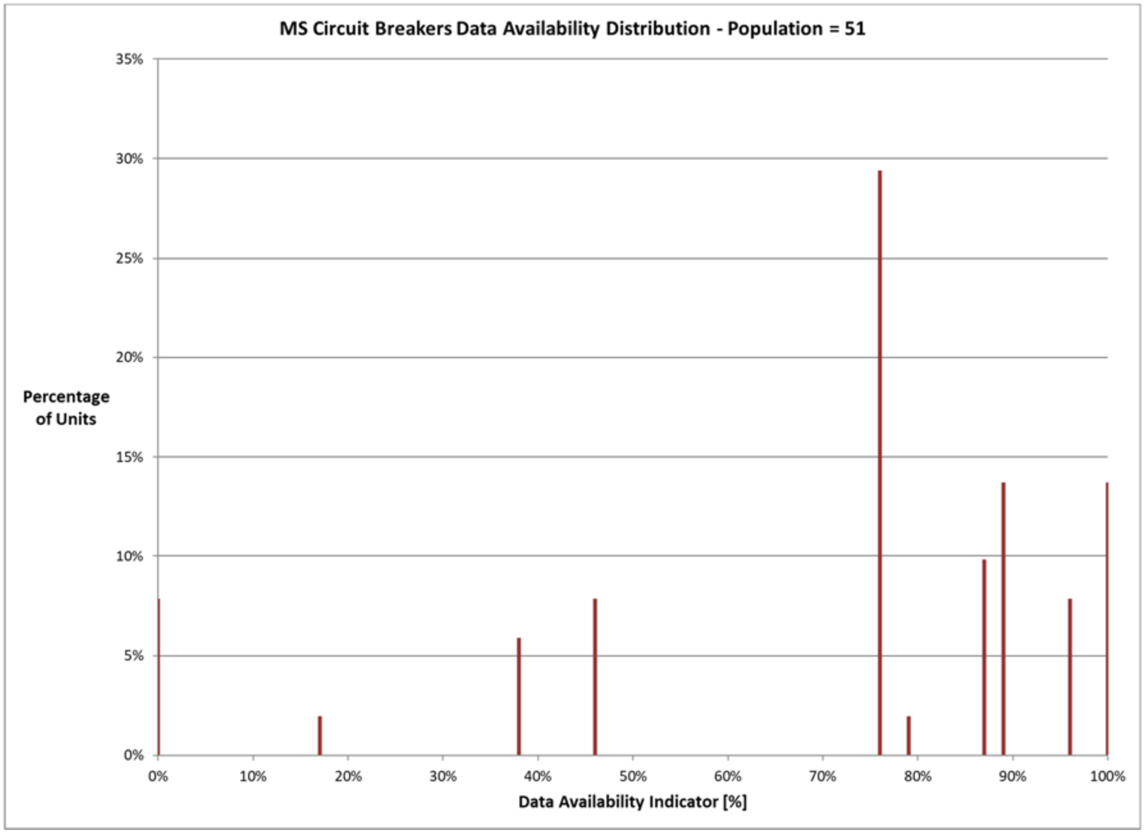

Figure 2-7 Circuit Breakers Data Availability Distribution

Among the three types, the average data availabilities were 82%, 38% and 29% for air magnetic, bulk oil and vacuum circuit breakers respectively.

Data Gap

The following table summarizes the data gaps for MS Circuit Breakers.

Table 2-15 Data Gap for MS Circuit Breakers

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Arc Contact	Contact Performance	☆	Arc contact	Contact erosion	Visual inspection or on-site testing
Oil Quality	Arc Extinction	☆ ☆ ☆	Breaker Oil (OCB only)	Poor oil quality	Lab testing
Vacuum Bottle			Vacuum bottle (VCB Only)	Vacuum pressure low	On-site testing

Preventive Maintenance Schedule

According to generic industrial experience, the following table summarizes the preventive maintenance periodicity for MS Circuit Breakers.

Table 2-16 Preventive Maintenance Periodicity for MS Circuit Breakers

Maintenance Item	Maintenance Periodicity
Routine condition inspection	Semi-annually to annually
Oil sampling (OCBs only)	Every 2 years
Contact resistance, timing, leaking test	Every 3 to 5 years
AC insulation test	Every 4 to 8 years
Complete Inspection	At the end of operation cycle limit

3. MS SWITCHGEAR

3.1. Health Index Formula of MS Switchgear

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

3.1.1. Condition and Sub-Condition Parameters

Table 3-1 MS Switchgear Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	6	Table 3-2
2	Switch/Fuse Condition	3	Table 3-3
3	Insulation	3	Table 3-4
4	Service Record	8	Table 3-5
	Age limiter*		Figure 3-1

* Age limiter sets the maximum HI a unit can reach based on its age

Table 3-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Finish Inside & Out	1	Table 3-6
2	Porcelain/Glastic Supports	1	Table 3-6

Table 3-3 Switch/Fuse Condition Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Static Contact Bottles	1	Table 3-6
2	Switch Resistance	2	Table 3-6

Table 3-4 Insulation Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Insulators and Barriers	1	Table 3-6
2	Bus and Bus Insulation	1	Table 3-6

Table 3-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Comments	2	Table 3-7

3.1.2. *Condition Criteria*

Station Inspection

Table 3-6 Inspection Condition Criteria

CPF	Description
4	0
3	1
2	2
1	3
0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score			Weight
	0	2	4	
2020	Good	OK	Any defect intervention	1
2019				0.9
2018				0.8
2017				0.7
2016				0.6
2015				0.5
2014				0.4
2013				0.3
2012				0.2
2011				0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight_i}$

Where i refers to the year the inspection was conducted

Overall Station Inspection

Table 3-7 Comment Condition Criteria

CPF	Description (Overall count)
4	0
3	1
2	2
1	3
0	4

Where overall count is calculated based on detection of specific defects as below:

Year	Score			Weight
	0	3	4	
2020	Good	Pass	Any defect intervention	1
2019				0.9
2018				0.8
2017				0.7
2016				0.6
2015				0.5
2014				0.4
2013				0.3
2012				0.2
2011				0.1

Inspection count = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Age

In the case of MS Switchgear, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 55 and 75 years the probability of failures (P_f) for MS Switchgear are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 3-1.

Table 3-8 Age Limiting Curve Parameters - MS Switchgear

Asset Type	α	β
MS Switchgear	**65.38**	**9.27**

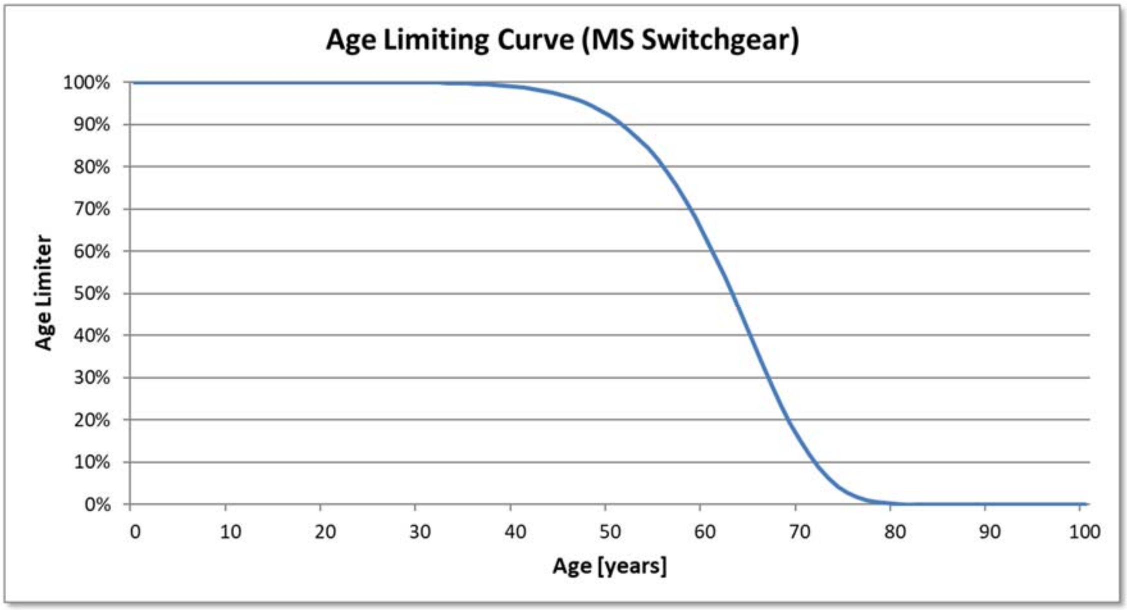

Figure 3-1 MS Switchgear Age Limiter Criteria

3.2. Age Distribution of MS Switchgear

The age distribution for this asset class was shown on the figure below. The average age of the population was 49.

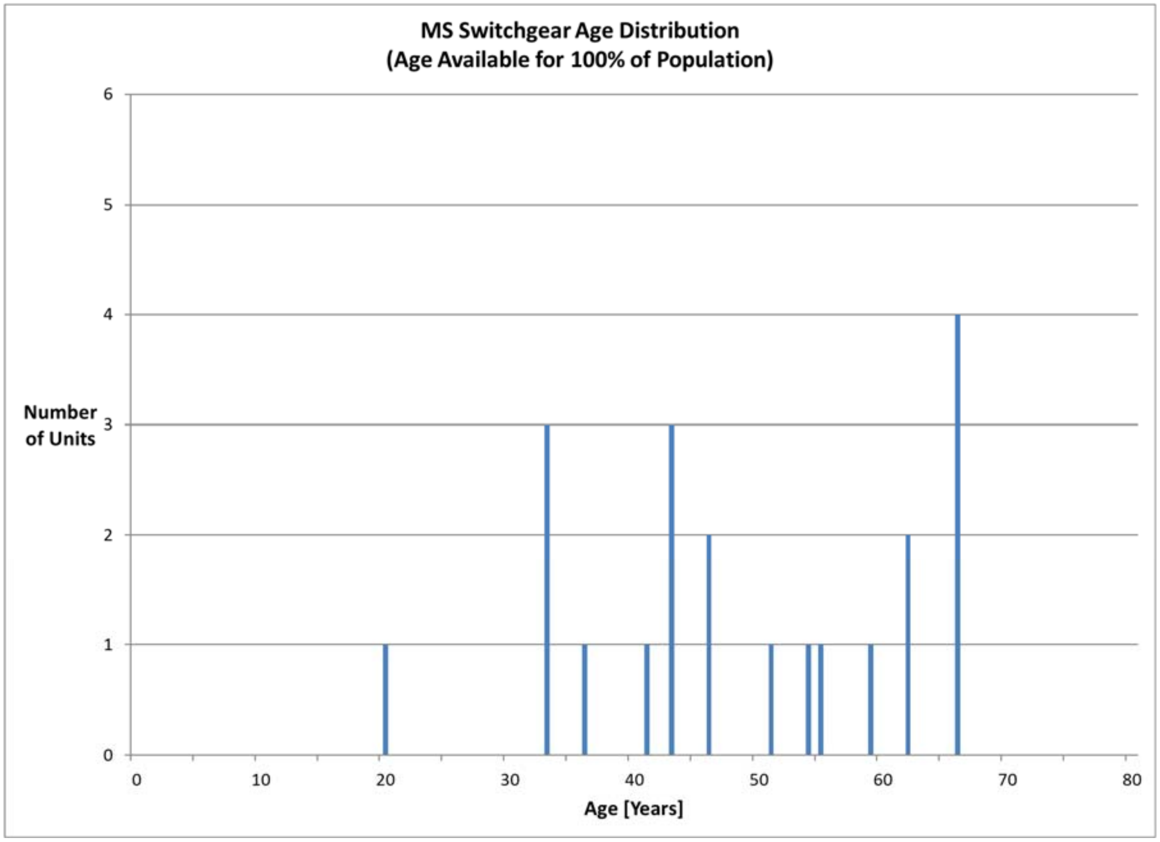

Figure 3-2 MS Switchgear Age Distribution

3.3. Health Index Results of MS Switchgear

There were 21 units of MS Switchgear at BWP. All of them had at least basic data for a Health Indexing.

The average Health Index for this asset group was 55%. About 38% of the population was found to be in “poor” or “very poor” condition.

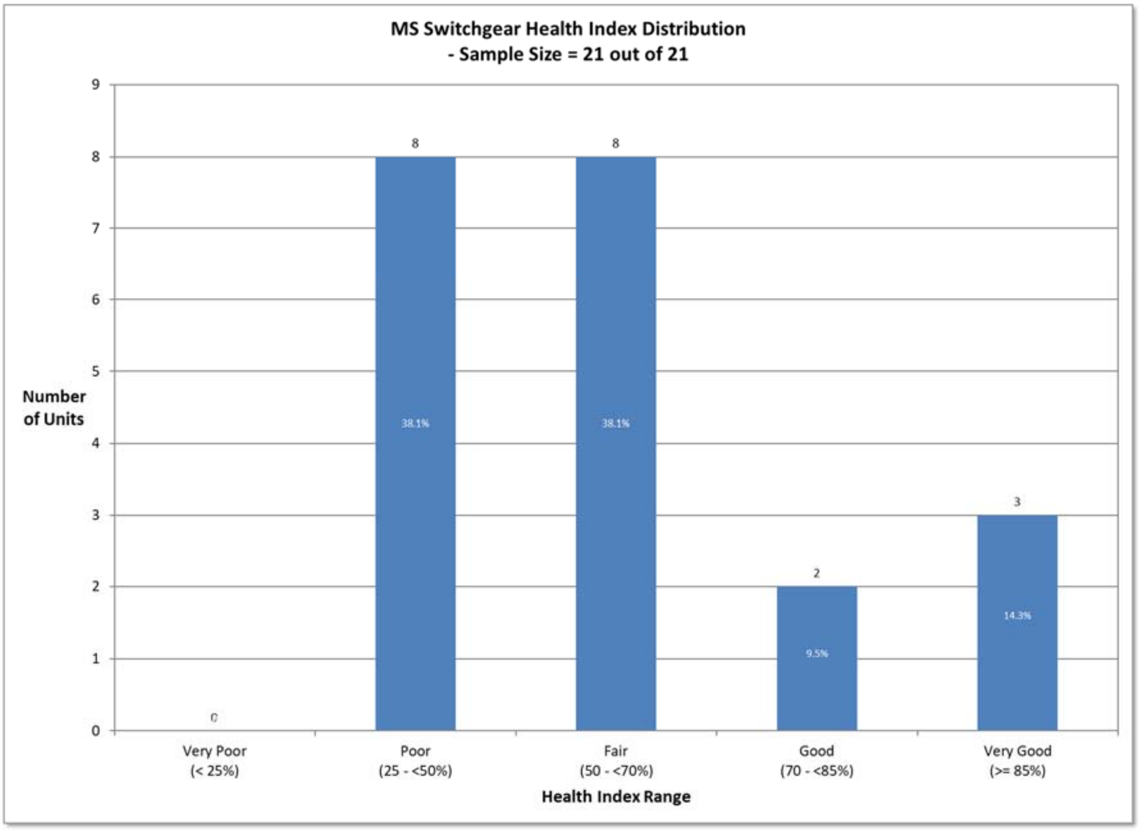

Figure 3-3 MS Switchgear Health Index Distribution

3.4. Condition-Based Flagged-for-Action Plan of MS Switchgear

It is assumed that MS Switchgear was proactively replaced. The risk of a unit failure is equal to the product of its probability of failure and criticality. A unit becomes a candidate for replacement when its risk is greater than or equal to one.

As in this study, all MS Switchgear were assumed to have equal criticalities of 1.25, the flagged-for-action plan became condition-based. In such a case, a unit with a probability of failure of 80% became a candidate for action.

The flagged-for-action plan for MS Switchgear was given below:

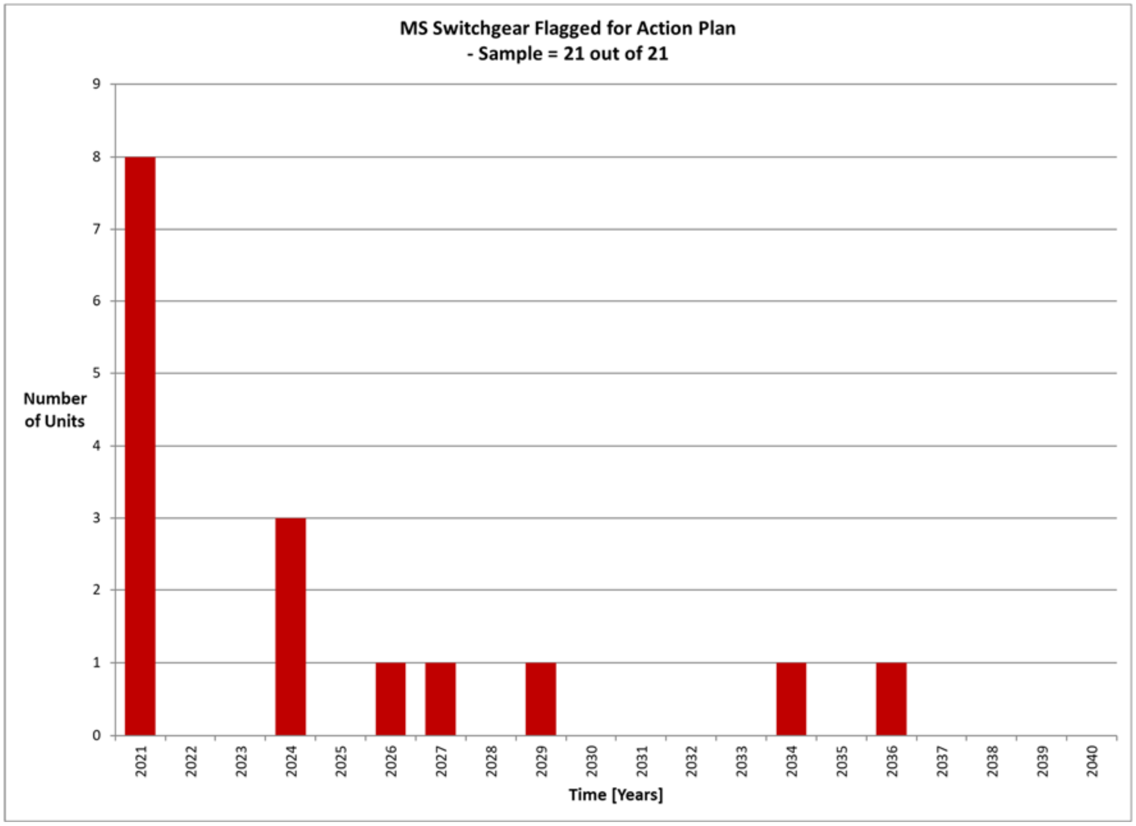

Figure 3-4 MS Switchgear Condition-Based Flagged-for-Action Plan

3.5. Condition-Based Prioritization List of MS Switchgear

The following table shows the condition-based prioritization list for MS Switchgear.

Table 3-9 Condition-Based Prioritization List of MS Switchgear

Rank	Unique ID	Address	Age	Health Index	Probability of Failure	Action Year From Now
1	1T1-1T2	[redacted]	33	25.0%	>90%	0
2	5F3-B	[redacted]	66	29.4%	>90%	0
3	5T1-A	[redacted]	66	29.4%	>90%	0
4	5F2-B	[redacted]	66	29.4%	>90%	0
5	8T1-A	[redacted]	62	32.5%	>90%	0
6	12T1-A	[redacted]	55	32.5%	>90%	0
7	11T1-A	[redacted]	54	32.5%	>90%	0
8	32T1-A	[redacted]	66	33.6%	>90%	0
9	14F1-B	[redacted]	43	50.0%	70.9%	3
10	14T1-A	[redacted]	43	50.0%	70.9%	3
11	14F2-B	[redacted]	43	50.0%	70.9%	3
12	9T1-A	[redacted]	62	54.3%	57.9%	5
13	31T1-A	[redacted]	41	55.0%	54.0%	6
14	13T1-A	[redacted]	51	58.8%	44.0%	8
15	3T1-A	[redacted]	36	65.0%	22.7%	13
16	10T1-A	[redacted]	59	68.0%	18.4%	15
17	1T2-A	[redacted]	33	80.0%	2.0%	>20
18	1T1-A	[redacted]	33	80.0%	2.0%	>20
19	46T2-L	[redacted]	46	96.2%	0.0%	>20
20	46T1-L	[redacted]	46	96.2%	0.0%	>20
21	UBE -T1-L	[redacted]	20	100.0%	0.0%	>20

3.6. Data Analysis of MS Switchgear

The data available for this asset category included inspection results only.

Data Availability Indicator

The average DAI was 67%. The data availability distribution for the entire population was as follows:

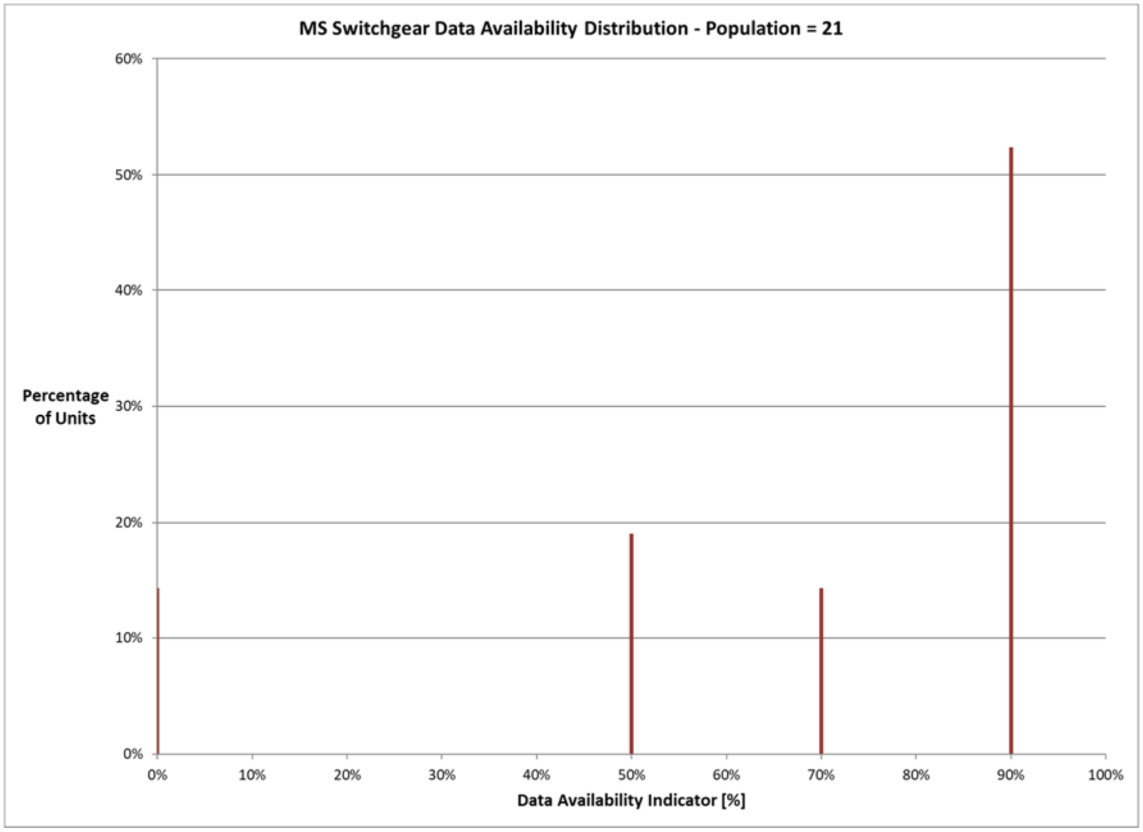

Figure 3-5 MS Switchgear Data Availability Distribution

Data Gap

The major data gap was that some units did not have any information other than age.

Although the inspection records were available, in most cases there was only the last reading available.

There was no other major data gap in this asset group.

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4. POLE TOP TRANSFORMERS

4.1. Health Index Formula of Pole Top Transformers

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

4.1.1. Condition and Sub-Condition Parameters

Table 4-1 Pole Top Transformers Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	1	Table 4-2
2	Connection and Insulation	2	Table 4-3
3	Service Record	6	Table 4-4
	Age limiter*		Figure 4-1
	De-Rating Factor (DR)		Table 4-8

* Age limiter sets the maximum HI a unit can reach based on its age

Table 4-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Rust	1	Table 4-5

Table 4-3 Connection and Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	4	Table 4-5
2	Connectors	2	Table 4-5
3	Arrester	1	Table 4-5
4	Insulator	2	Table 4-5
5	Bushings	2	Table 4-5
6	Elbows	1	Table 4-5

Table 4-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 4-6

4.1.2. Condition Criteria

Visual Inspection

Table 4-5 Visual Inspection Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on BWP Inspection Database as below:

Year	Score (by Defect)	Weight
	4	
2020	Yes	1
2019		0.9
2018		0.8
2017		0.7
2016		0.6
2015		0.5
2014		0.4
2013		0.3
2012		0.2
2011		0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Overall Condition

Table 4-6 Overall Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where overall count is calculated based on overall risk rating count as below:

Year	Score (by overall Risk rating)					Weight
	0	1	2	3	4	
2020	Green	Blue	Yellow	Orange	Red	1
2019						0.9
2018						0.8
2017						0.7
2016						0.6
2015						0.5
2014						0.4
2013						0.3
2012						0.2
2011						0.1

$$\text{Inspection count} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Where i refers to the year the inspection was conducted

Age

In the case of Pole Top Transformers, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 35 and 55 years the probability of failures (P_f) for Pole Top Transformers are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 4-1.

Table 4-7 Age Limiting Curve Parameters - Pole Top Transformers

Asset Type	α	β
Pole Top Transformers	**45.23**	**6.11**

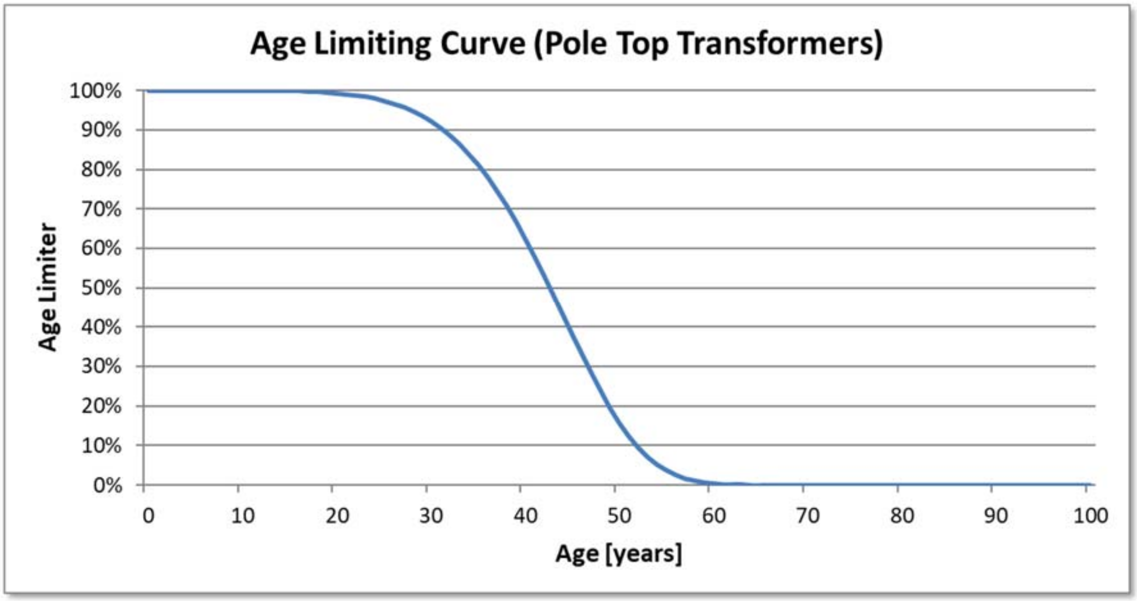

Figure 4-1 Pole Top Transformers Age Limiter Criteria

De-Rating Factor (DRF)

Table 4-8 De-Rating Criteria

Year	**Description (by IR Test Priority)**	
	Red	**Yellow**
2020	0.5	0.7
2019	0.7	0.9
2018	0.9	1
2017	1	1
< 2017	1	1

4.2. Age Distribution of Pole Top Transformers

Single Phase Pole Top Transformers

The average age of all single phase units that had age information was 31 years.

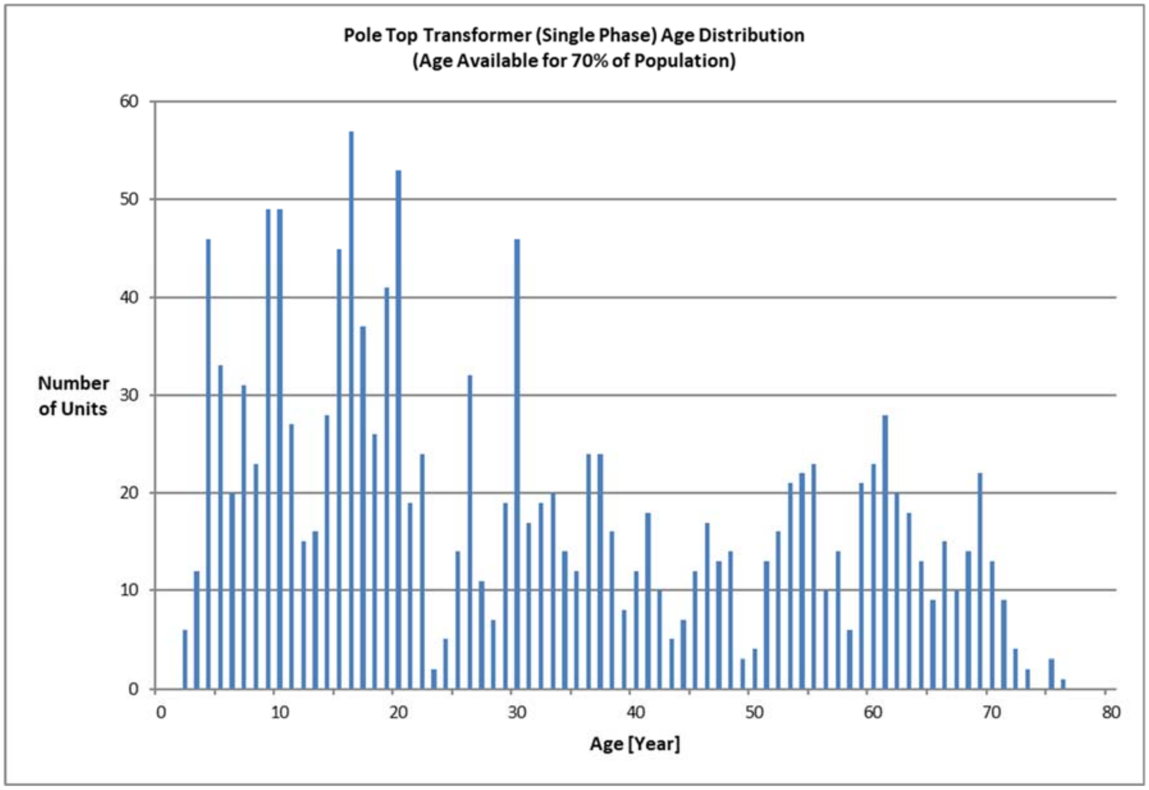

Figure 4-2 Single Phase Pole Top Transformers Age Distribution

Poly Phase Pole Top Transformers

The average age of all poly phase units that had age information was 24 years.

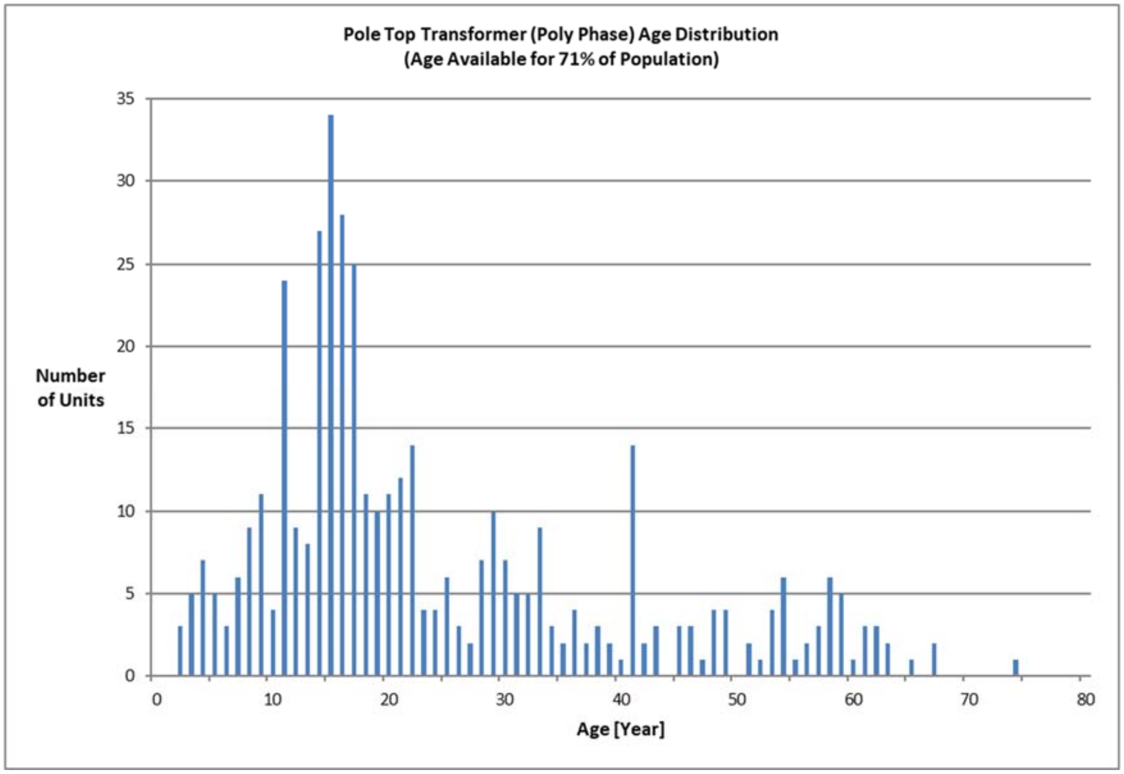

Figure 4-3 Poly Phase Pole Top Transformers Age Distribution

Rabbit Type Pole Top Transformers

The average age of all rabbit type units that had age information was 16 years.

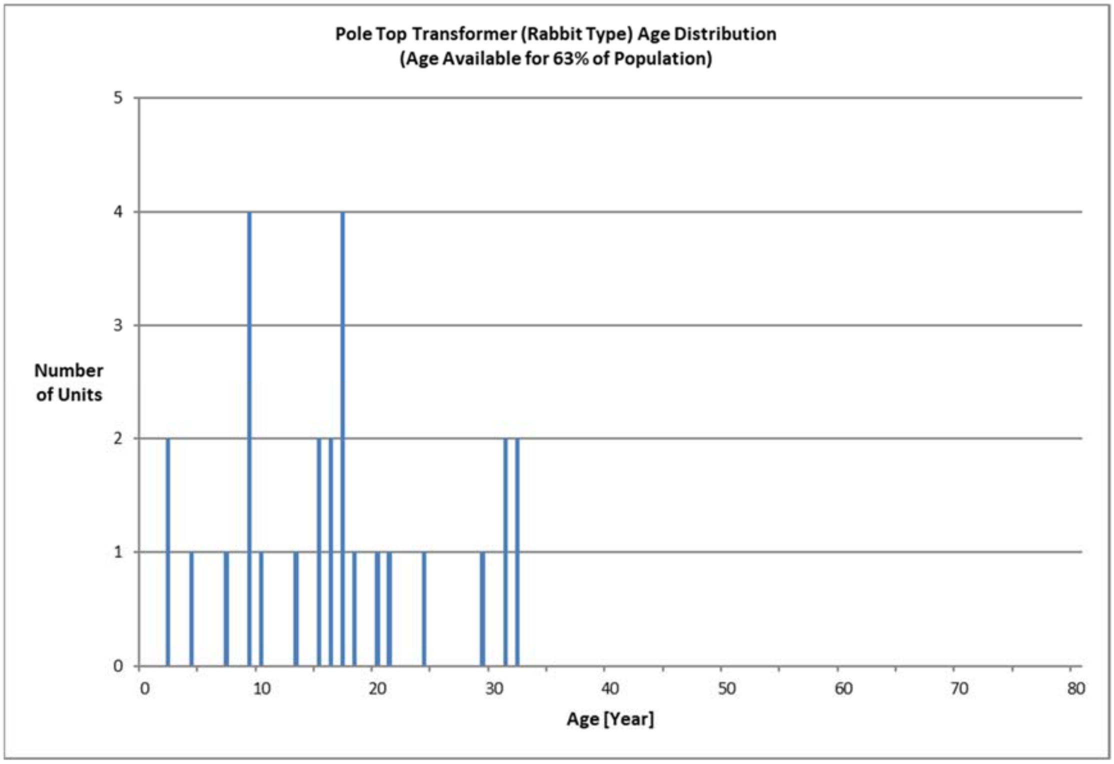

Figure 4-4 Rabbit Type Pole Top Transformers Age Distribution

4.3. Health Index Results of Pole Top Transformers

Single Phase Pole Top Transformers

There were a total of 2003 Single Phase Pole Top Transformers at BWP. Of these, there were 1993 units with at least basic data for a Health Indexing.

The average sample Health Index for this sub asset group was 77%. Approximately 21% of the sample was found to be in "poor" or "very poor" condition.

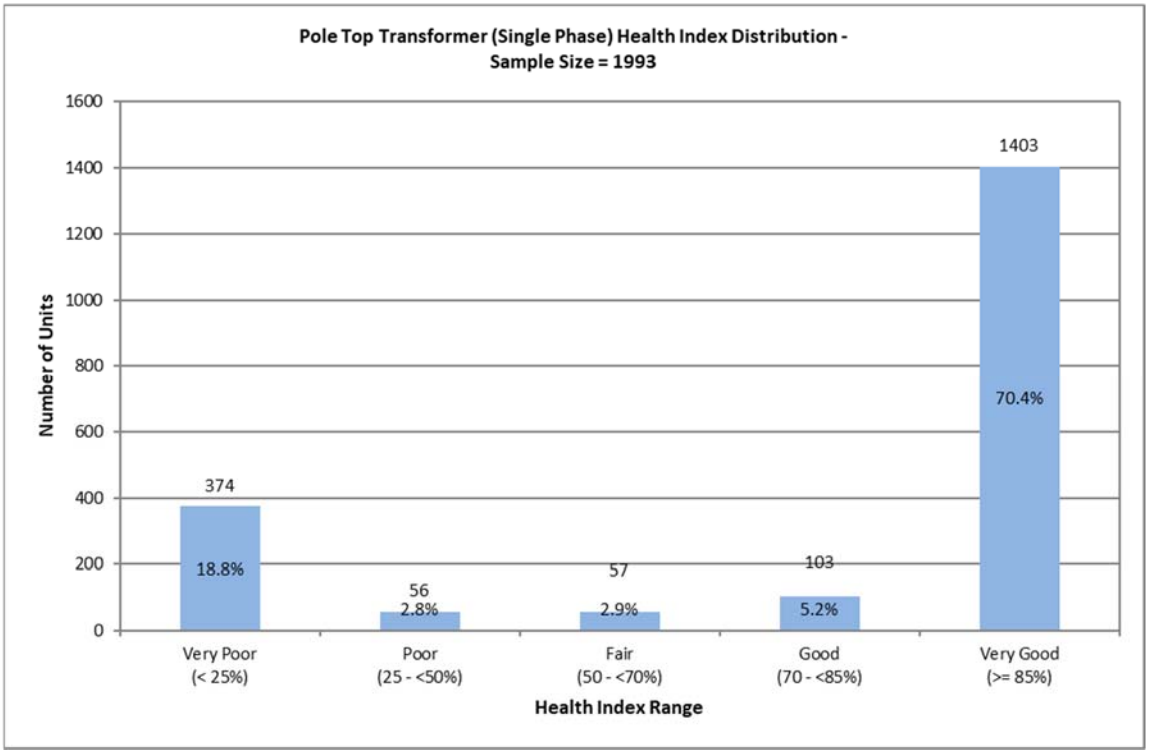

Figure 4-5 Single Phase Pole Top Transformers Health Index Distribution

Poly Phase Pole Top Transformers

There were a total of 598 Poly Phase Pole Top Transformers at BWP. Of these, there were 591 units with at least basic data for a Health Indexing.

The average sample Health Index for this sub asset group was 88%. About 11% the sample was found to be in “poor” or “very poor” condition.

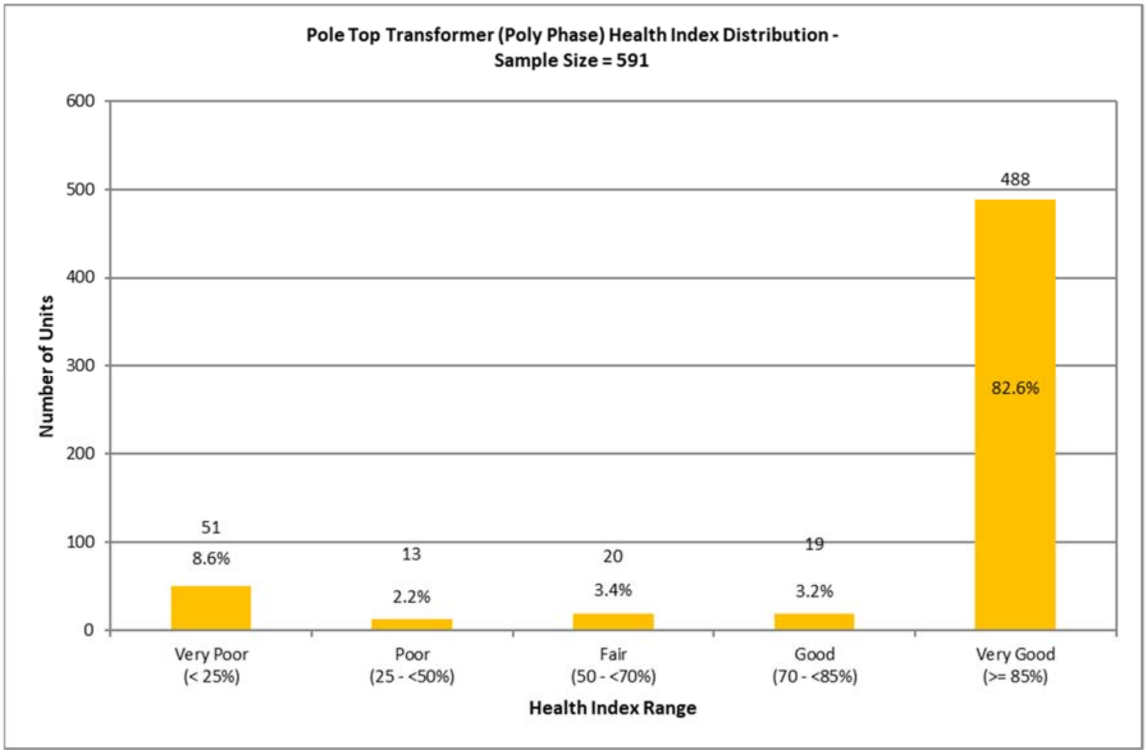

Figure 4-6 Poly Phase Pole Top Transformers Health Index Distribution

Rabbit Type Pole Top Transformers

There were a total of 43 Rabbit Type Pole Top Transformers at BWP. All the units had at least basic data for a Health Indexing.

The average sample Health Index for this sub asset group was 98%. None of the sample was found to be in “poor” or “very poor” condition.

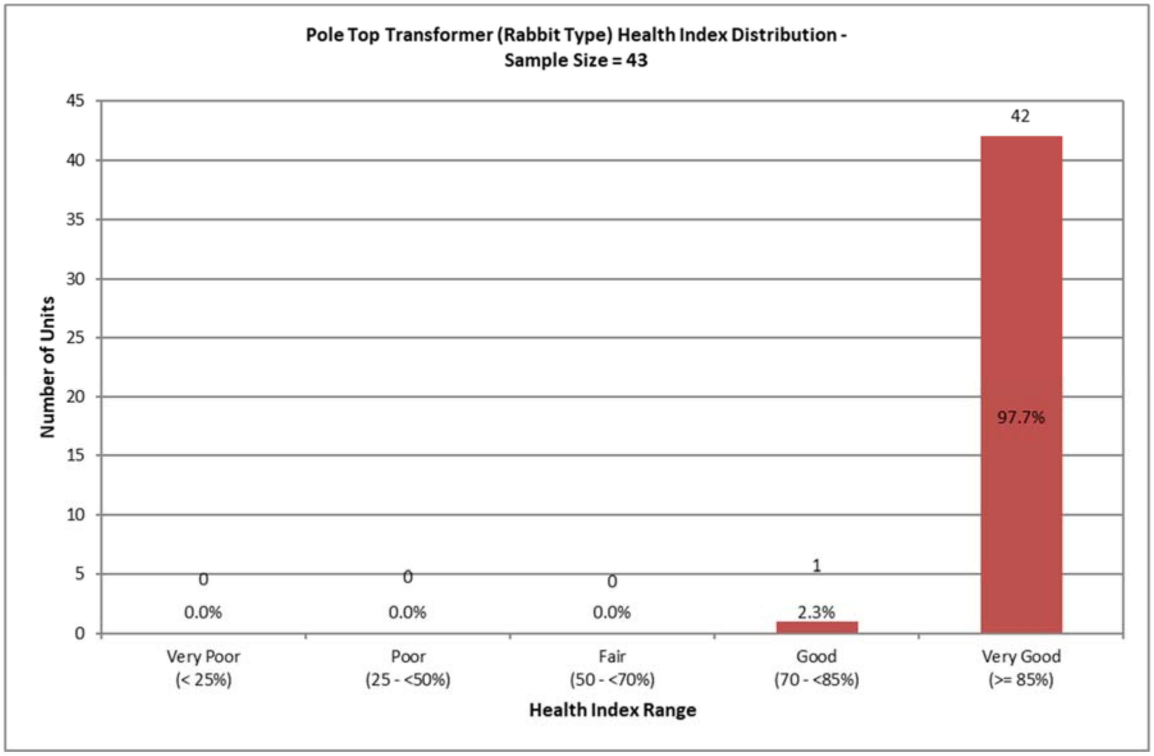

Figure 4-7 Rabbit Type Pole Top Transformers Health Index Distribution

4.4. Condition-Based Flagged-for-Action Plan of Pole Top Transformers

As it is assumed that Pole Top Transformers were reactively replaced, the flagged-for-action plan was based on the asset failure rate, f(t).

Single Phase Pole Top Transformers

Based on extrapolation from HI status of sample units, the flagged-for-action plan was as follows:

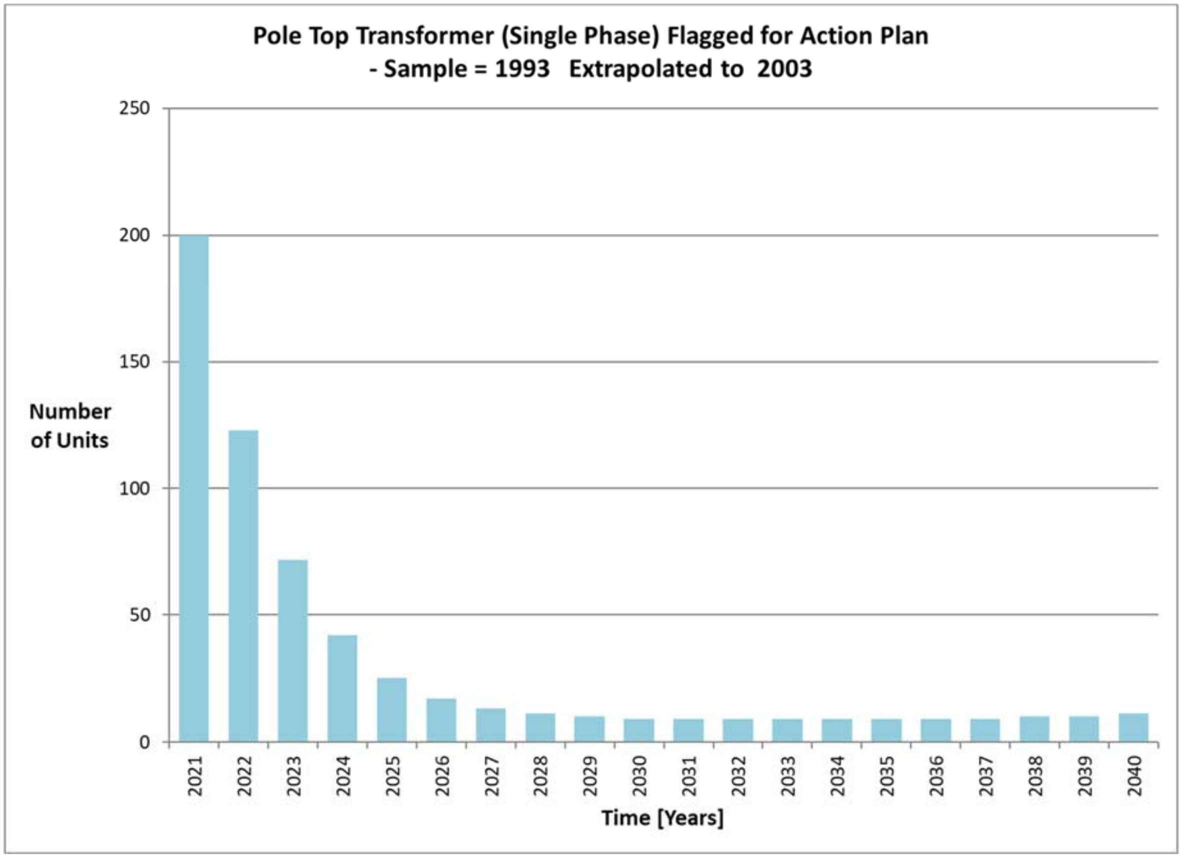

Figure 4-8 Single Phase Pole Top Transformers Condition-Based Flagged-for-Action Plan

Poly Phase Pole Top Transformers

Based on extrapolation from HI status of sample units, the flagged-for-action plan was as follows:

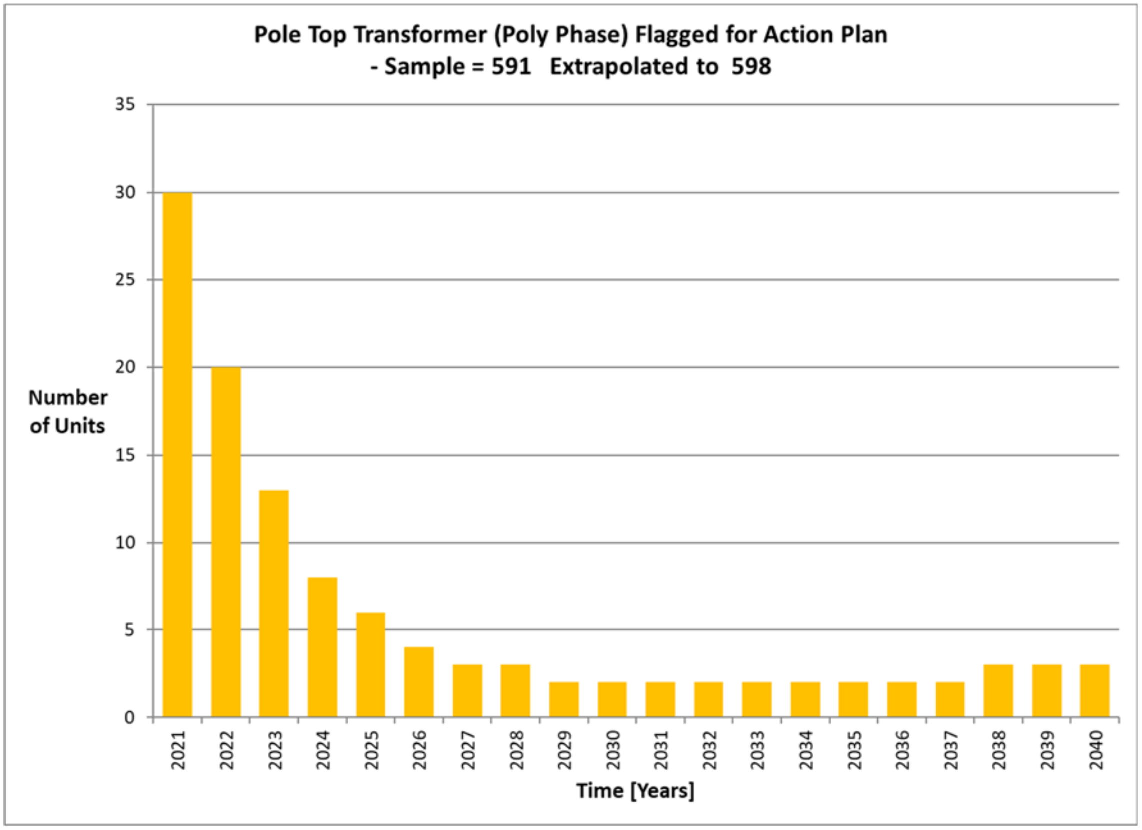

Figure 4-9 Poly Phase Pole Top Transformers Condition-Based Flagged-for-Action Plan

Rabbit Type Pole Top Transformers

Based on extrapolation from HI status of sample units, the flagged-for-action plan was as follows:

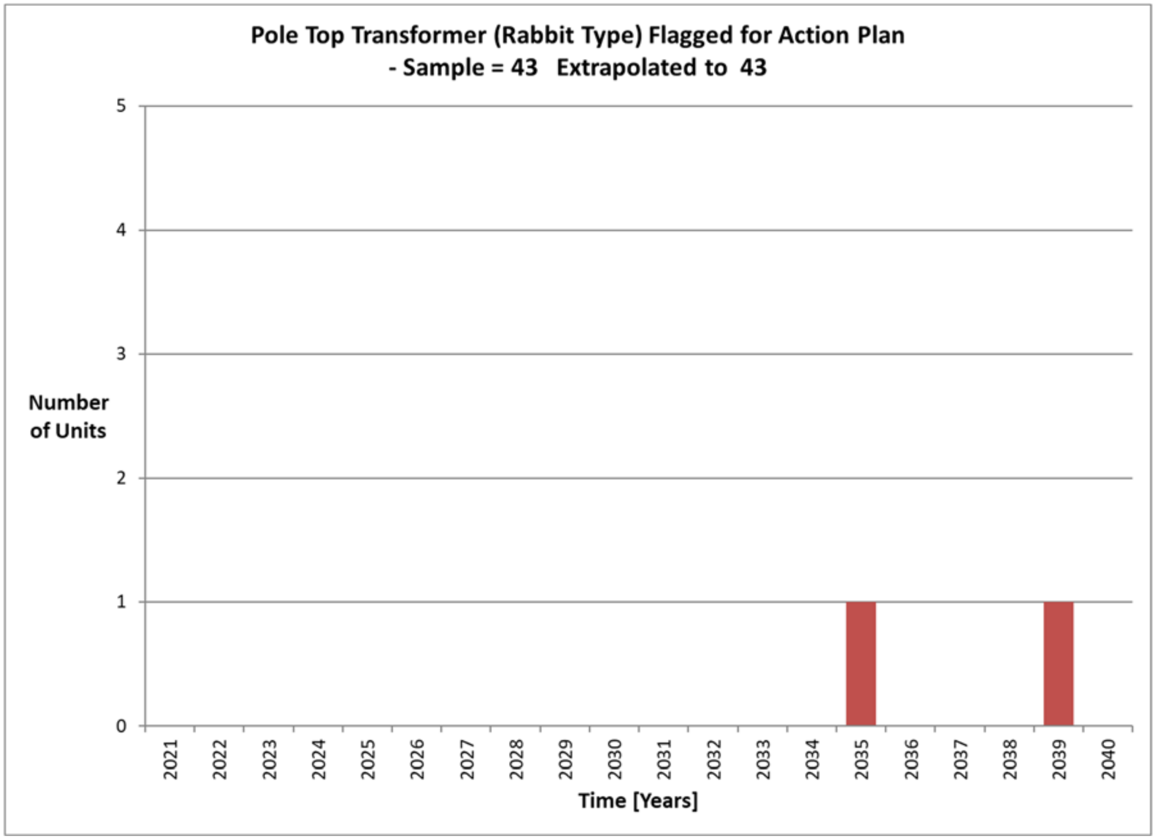

Figure 4-10 Rabbit Type Pole Top Transformers Condition-Based Flagged-for-Action Plan

4.5. Data Analysis of Pole Top Transformers

The data available for this asset category included age and inspection results.

Data Availability Indicator

The data availability distribution for the entire population was as follows:

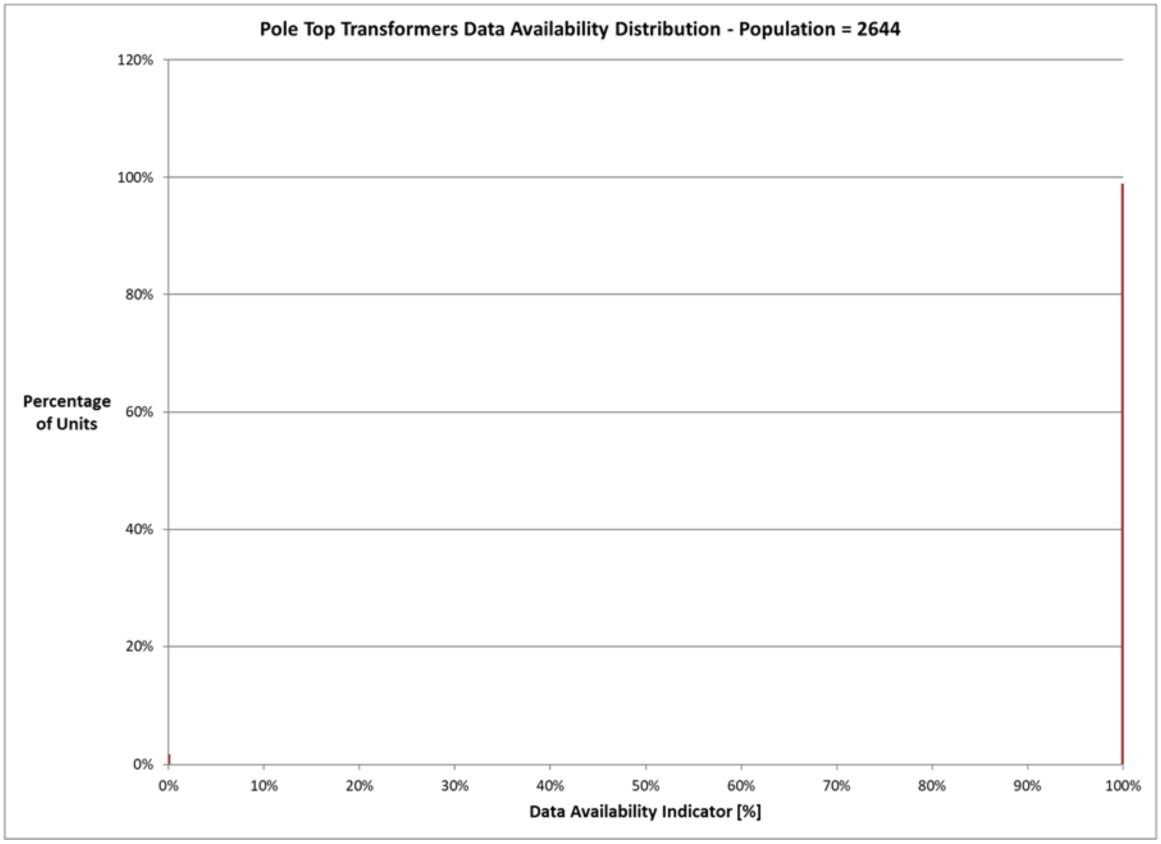

Figure 4-11 Pole Top Transformers Data Availability Distribution

Among the three types, the average data availabilities were 99%, 96% and 86% for single phase, poly phase and rabbit type pole top transformers respectively.

Data Gap

The following table summarizes the data gaps for Pole Top Transformers.

Table 4-9 Data Gap for Pole Top Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Grounding	Connection & Insulation	☆	Transformer tank	Poor grounding wire connection	Visual inspection
Loading	Service Record	☆ ☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

5. GANG OPERATED OVERHEAD SWITCHES

5.1. Health Index Formula of Gang Operated Overhead Switches

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

5.1.1. Condition and Sub-Condition Parameters

Table 5-1 Gang Operated Overhead Switches Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Operating Mechanism	1	Table 5-2
2	Insulation & Connection	1	Table 5-3
3	Service Record	3	Table 5-4
	Age Limiter*		
	De-Rating Multiplier (DR)		Table 5-8

* Age limiter sets the maximum HI a unit can reach based on its age

Table 5-2 Operating Mechanism Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Bent Broken	2	Table 5-5
2	Locks	1	Table 5-5

Table 5-3 Insulation & Connection Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Connection	1	Table 5-5
2	Grounding	1	Table 5-5

Table 5-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	1	Table 5-6

5.1.2. Condition Criteria

Visual Inspections

Table 5-5 Visual Inspection Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on BWP Inspection Database as below:

Year	Score (by Defect)	Weight
	4	
2020	Yes	1
2019		0.9
2018		0.8
2017		0.7
2016		0.6
2015		0.5
2014		0.4
2013		0.3
2012		0.2
2011		0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Overall Condition

Table 5-6 Overall Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where overall count is calculated based on overall risk rating count as below:

Year	Score (by overall Risk rating)					Weight
	0	1	2	3	4	
2020	Green	Blue	Yellow	Orange	Red	1
2019						0.9
2018						0.8
2017						0.7
2016						0.6
2015						0.5
2014						0.4
2013						0.3
2012						0.2
2011						0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Age

In the case of Gang Operated Overhead Switches, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 50 and 60 years the probability of failures (P_f) for Gang Operated Overhead Switches are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 5-1.

Table 5-7 Age Limiting Curve Parameters - Gang Operated Overhead Switches

Asset Type	α	β
Gang Operated Overhead Switches	**55.55**	**14.25**

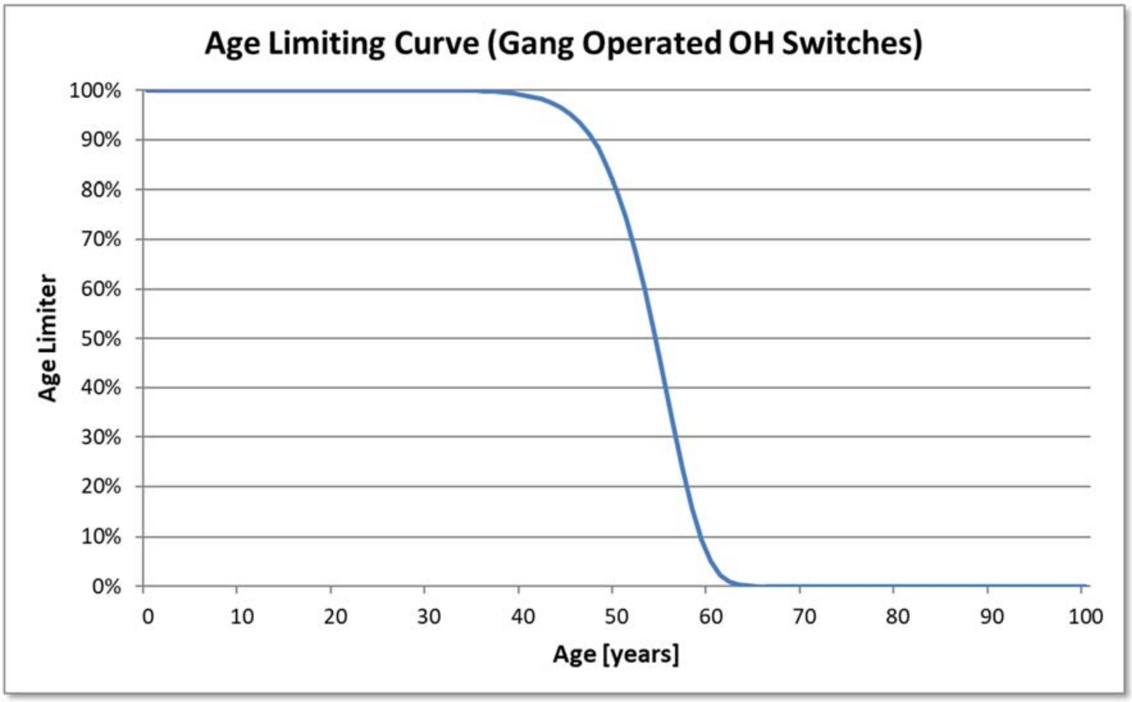

Figure 5-1 Gang Operated Overhead Switches Age Limiting Criteria

De-Rating (DR) Multiplier

Table 5-8 Gang Operated Overhead Switches De-Rating Factors

Year	**Description (by IR Test Priority)**	
	Red	**Yellow**
2020	0.5	0.7
2019	0.7	0.9
2018	0.9	1
2017	1	1
< 2017	1	1

5.2. Age Distribution of Gang Operated Overhead Switches

The average age of all units was 16 years.

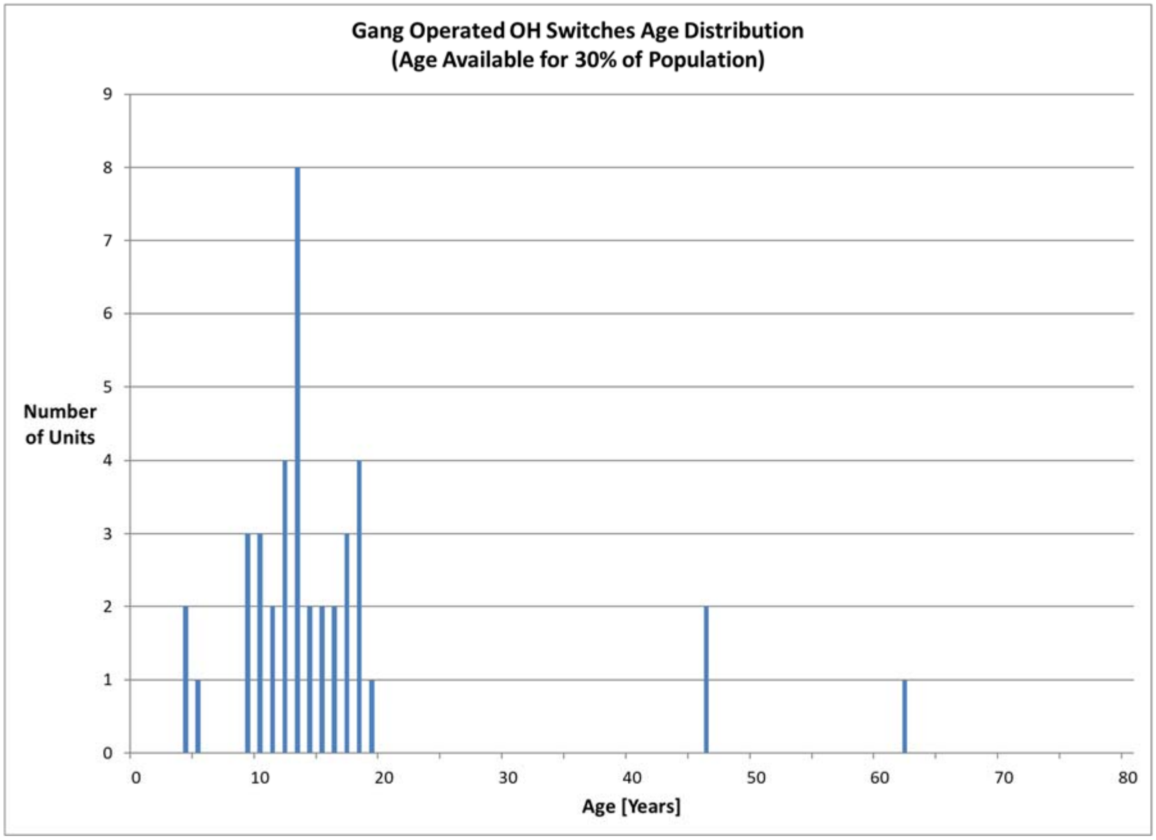

Figure 5-2 Gang Operated Overhead Switches Age Distribution

5.3. Health Index Results of Gang Operated Overhead Switches

There were 132 Gang Operated Overhead Switches at BWP. Of these, there were 103 units with at least basic data for a Health Indexing.

The average Health Index for this sub asset group was 99 %. None but one of the units was in "poor" or "very poor" condition.

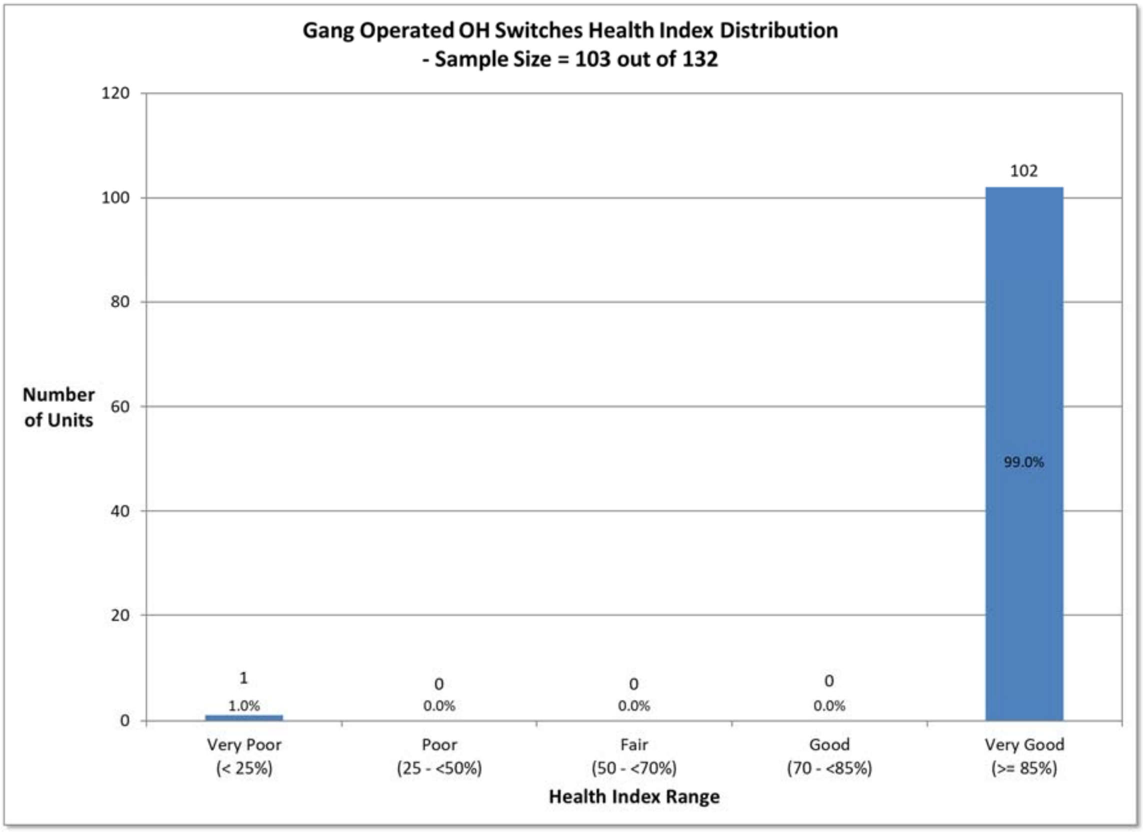

Figure 5-3 Gang Operated Overhead Switches Health Index Distribution

5.4. Condition-Based Flagged-for-Action Plan of Gang Operated Overhead Switches

As it is assumed that Gang Operated Overhead Switches were reactively replaced, the flagged-for-action plan was based on the asset failure rate, f(t).

Based on extrapolation from HI status of sample units, the flagged-for-action plan was as follows:

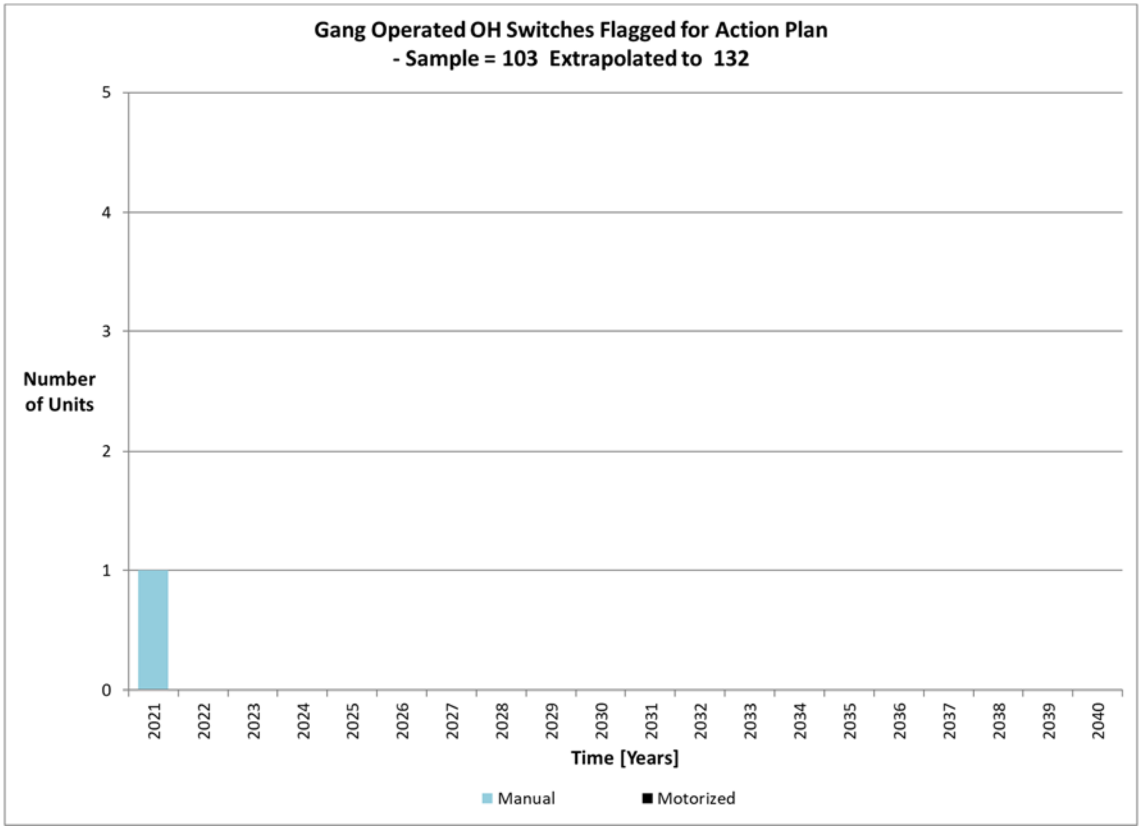

Figure 5-4 Gang Operated Overhead Switches Condition-Based Flagged-for-Action Plan

5.5. Data Analysis of Gang Operated Overhead Switches

The condition data for this asset category included visual inspection results and age.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

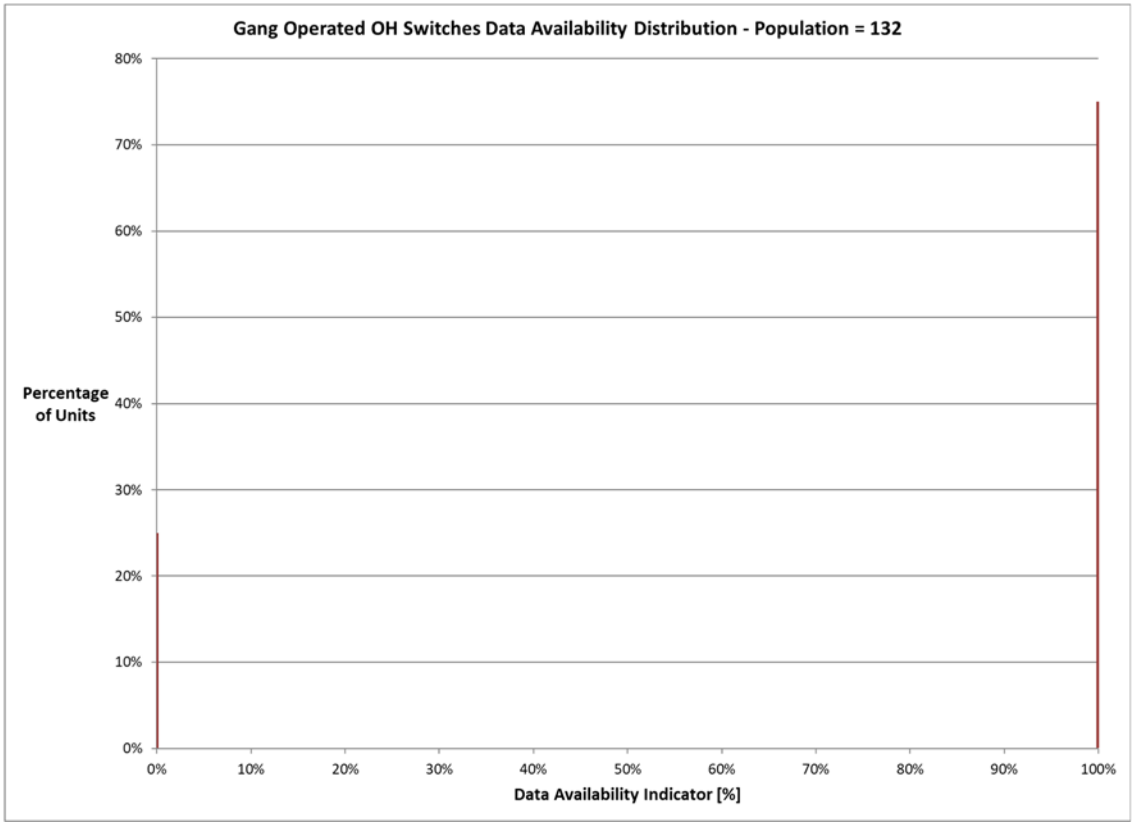

Figure 5-5 Gang Operated Overhead Switches Data Availability Distribution

The average data availabilities were 75%.

Approximately 22% of the population (29 out of 132 units) did not have any data for assessment.

Data Gap

The following table summarizes the data gaps for Gang Operated Overhead Switches.

Table 5-9 Data Gap for Gang Operated Overhead Switches

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		☆	Switch support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn-out	On-site visual inspection
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	On-site visual inspection
Insulator	**Insulation**	☆	Support insulator	Crack	On-site visual inspection

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6. WOOD POLES

6.1. Health Index Formula of Wood Poles

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

6.1.1. Condition and Sub-Condition Parameters

Table 6-1 Wood Poles Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	4	Table 6-2
2	Auxiliary accessories	1	Table 6-3
3	Service Record	3	Table 6-4
	Age Limiter *		Figure 6-1

* Age limiter sets the maximum HI a unit can reach based on its age

Table 6-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Broken Rot	2	Table 6-5
2	Decay	3	Table 6-6
3	Cavity	3	Table 6-6

Table 6-3 Auxiliary Accessories Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Crossarms	3	Table 6-5
2	Guy Tension	2	Table 6-5
3	Grounding	1	Table 6-5

Table 6-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	1	Table 6-7

6.1.2. Condition Criteria

<u>Visual Inspections</u>

Table 6-5 Visual Inspection Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on BWP Inspection Database as below:

	Score (by Defect)		
Year	0	4	Weight
2020	No	Yes	1
2019			0.9
2018			0.8
2017			0.7
2016			0.6
2015			0.5
2014			0.4
2013			0.3
2012			0.2
2011			0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Table 6-6 IML Pole Drilling Condition Criteria

Cavity IML Measurement	Cavity CPF	IML Condition Rating	Decay IML Measurement	Decay CPF
0-15	(60-2*IML)/15	PASS	0-35	(140-2*IML)/35
15-20	(25-IML)/5	MARGINAL	35-60	(85-IML)/25
20-100	(100-IML)/80	FAIL	60-100	(100-IML)/40

Drilling measurement indicates percentagewise deterioration severity.

The highest value of the multiple measurements is used in CPF calculation.

CPF is calculated as the remaining effectiveness normalized to 0-4 grading system

Overall Condition

Table 6-7 Overall Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where overall count is calculated based on overall risk rating count as below:

Year	Score (by overall Risk rating)					Weight
	2	2	2	3	4	
2020	Green	Blue	Yellow	Orange	Red	1
2019						0.9
2018						0.8
2017						0.7
2016						0.6
2015						0.5
2014						0.4
2013						0.3
2012						0.2
2011						0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Age

In the case of Wood Poles, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 45 and 65 years the probability of failures (P_f) for Wood Poles are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 6-1.

Table 6-8 Age Limiting Curve Parameters - Wood Poles

Asset Type	α	β
Wood Poles	**55.65**	**7.06**

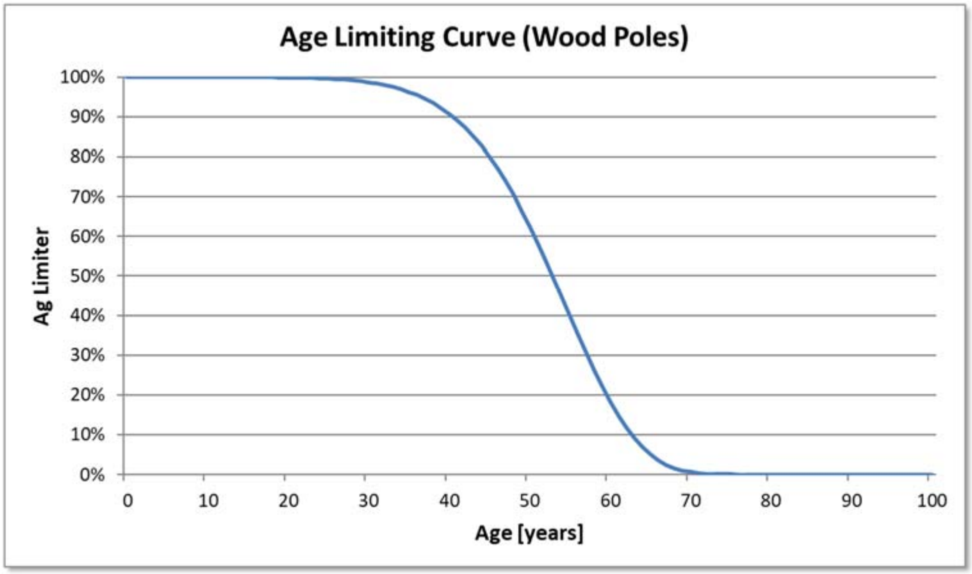

Figure 6-1 Wood Poles Age Limiter Criteria

6.2. Age Distribution of Wood Poles

The average age of all units was 29 years.

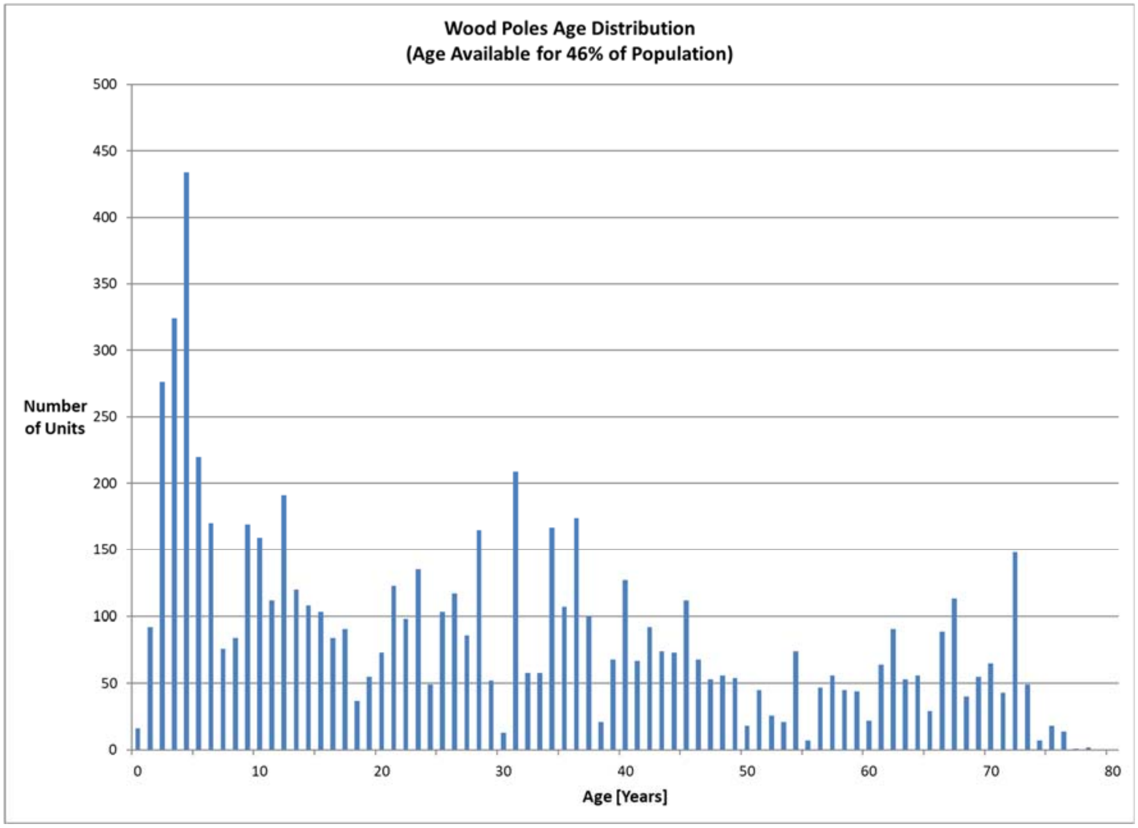

Figure 6-2 Wood Poles Age Distribution

6.3. Health Index Results of Wood Poles

There were 15361 Wood Poles at BWP. Of these, there were 15320 units with at least basic data for a Health Indexing.

The average Health Index for this asset group was 66%. About 8% of the population was in "poor" or "very poor" condition.

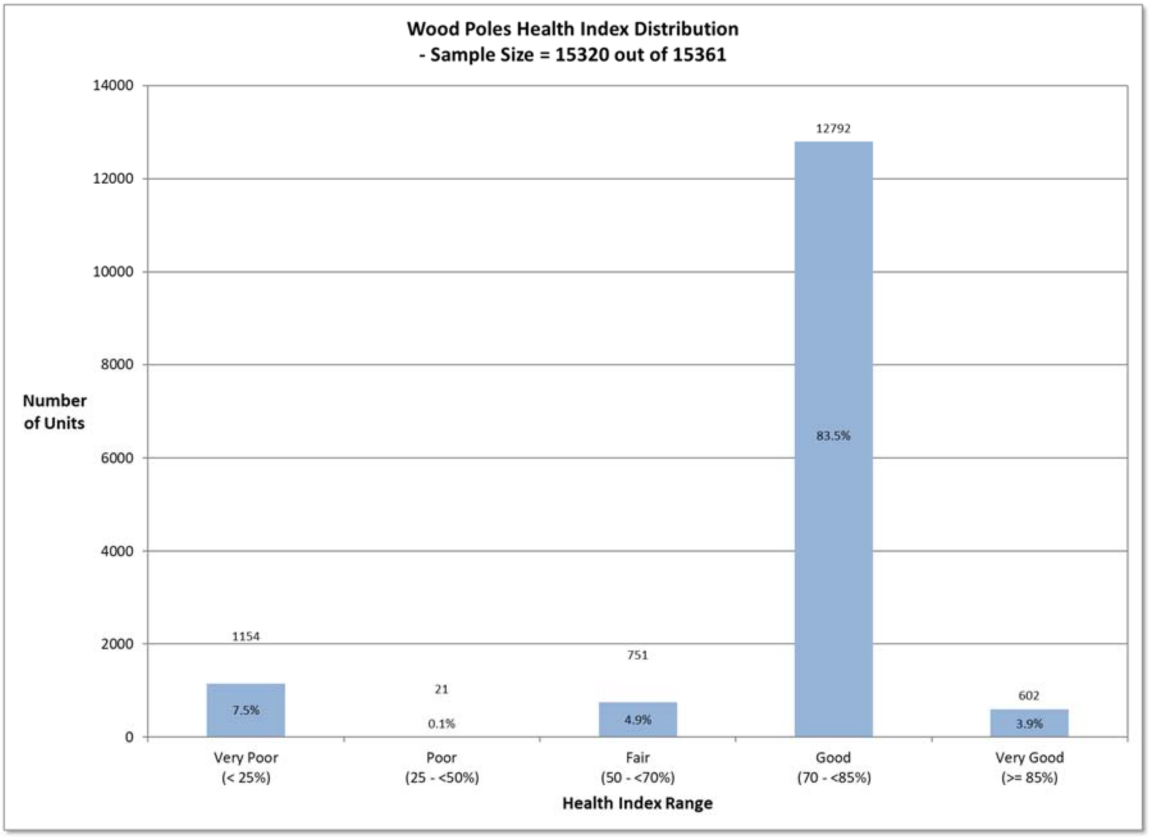

Figure 6-3 Wood Poles Health Index Distribution

6.4. Condition-Based Flagged-for-Action Plan of Wood Poles

Wood Poles are replaced both proactively and reactively: BWP conducts annual testing program and some of the poles are replaced before they fail based on the testing results while some are replaced only after they fail. The flagged-for-action plan shown in Figure 6-4 below is based on the poles failure rate f(t), i.e. *reactive* replacement, with the understanding that some of the poles will actually be replaced *proactively*.

The condition-based flagged-for-action plan was as follows:

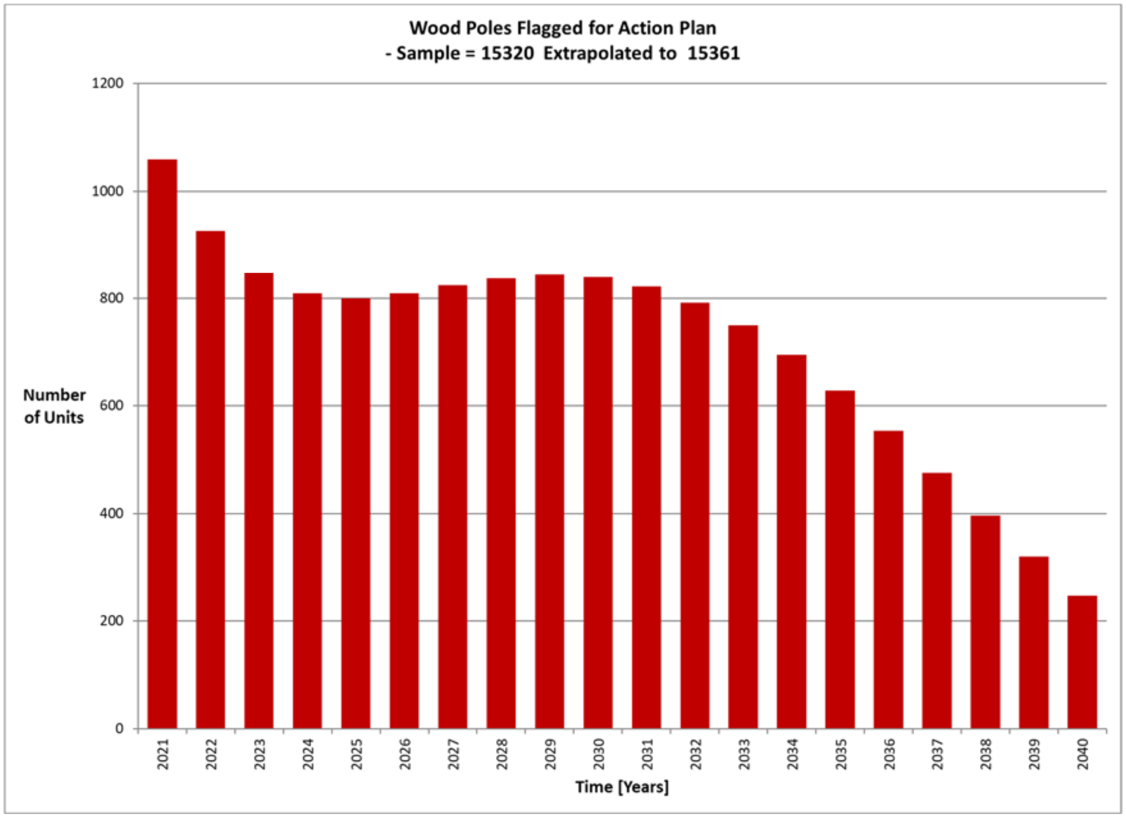

Figure 6-4 Wood Poles Condition-Based Flagged-for-Action Plan

6.5. Data Analysis of Wood Poles

The data for this asset category included visual inspection results and age.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

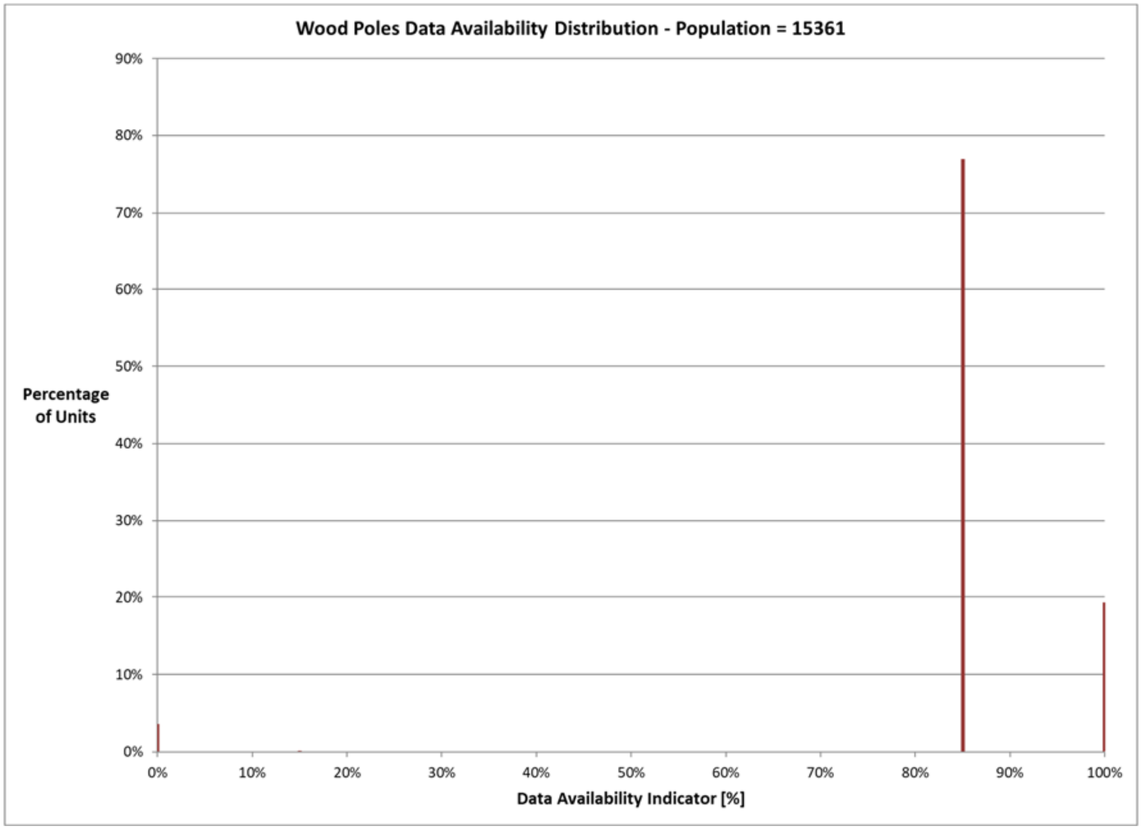

Figure 6-5 Wood Poles Data Availability Distribution

The average DAI of all units was 85%.

Data Gap

The following table summarizes the data gaps for Wood Poles.

Table 6-9 Data Gap for Wood Poles

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Physical Damage	Physical Condition	☆☆	Pole	Damage due to external forces (vehicle, lightning etc.)	On-site visual inspection
				Biological damage (ant, woodpecker etc)	
Physical Status		☆☆	Pole	Separation	On-site visual inspection
				Void	
				Lean	
				Misalignment	

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7. UNDERGROUND CABLES

7.1. Health Index Formula of Underground Cables

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.1.1. Condition and Sub-Condition Parameters

Table 7-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 7-2
DRF	De-Rating based on number of failures		Table 7-4

Table 7-2 Service Record Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Age	1	Figure 7-1, Figure 7-2

7.1.2. Condition Criteria

Age

In the case of Underground Cables, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 40 and 65 years the probability of failures (P_f) for XLPE In Duct Underground Cables are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 7-1.

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for XLPE Direct Buried Underground Cables are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 7-2.

Assuming that at the ages of 65 and 75 years the probability of failures (P_f) for PILC In Duct Underground Cables are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 7-3.

Table 7-3 Age Limiting Curve Parameters - Underground Cables

Asset Type	α	β
Underground Cables – XLPE ID	**48.08**	**8.16**
Underground Cables – XLPE DB	**40.47**	**10.33**
Underground Cables – PILC	**70.6**	**18.15**

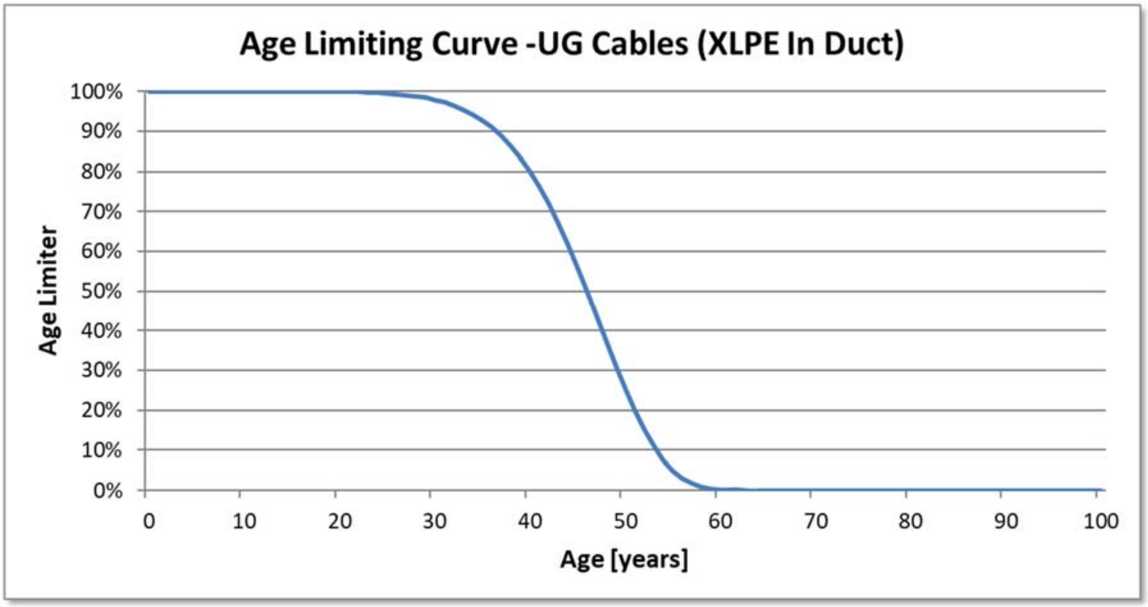

Figure 7-1 Underground Cables Age Limiting Criteria (XLPE In Duct)

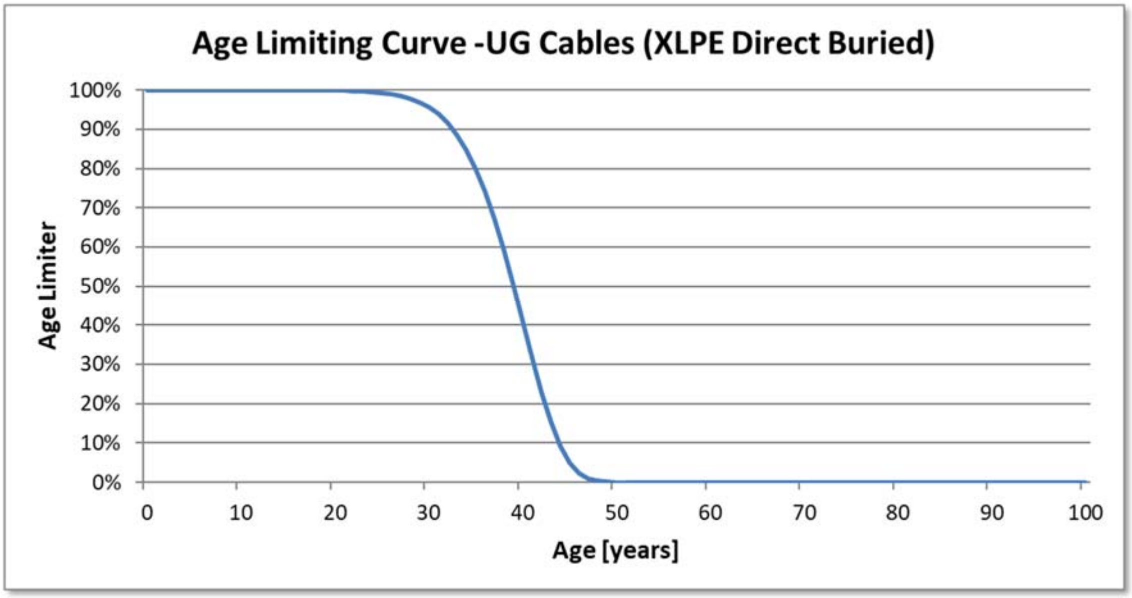

Figure 7-2 Underground Cables Age Limiting Criteria (XLPE Direct Buried)

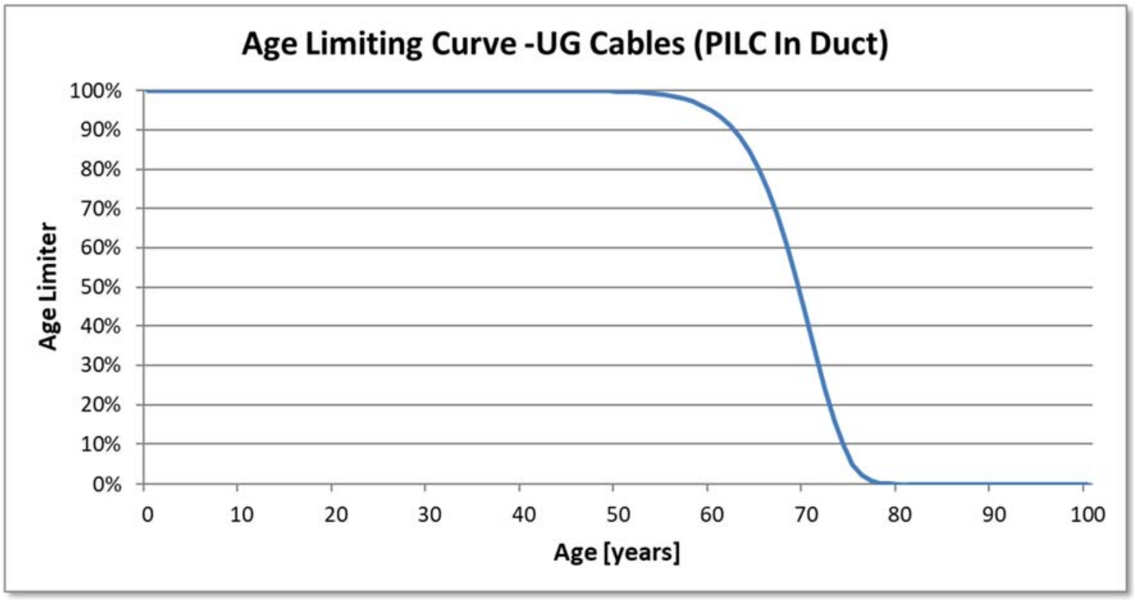

Figure 7-3 Underground Cables Age Condition Criteria (PILC In Duct)

De-Rating Factor (DRF)

Table 7-4 Number of Failures De-Rating Criteria

XLPE Installation Year	De-Rating Multiplier
Since 1980 (assume TR)	1
Before 1980 (assume non TR)	0.8

7.2. Age Distribution of Underground Cables

XLPE Direct Buried

The average age was 41 years / conductor-km. The age distribution for this asset category was as follows:

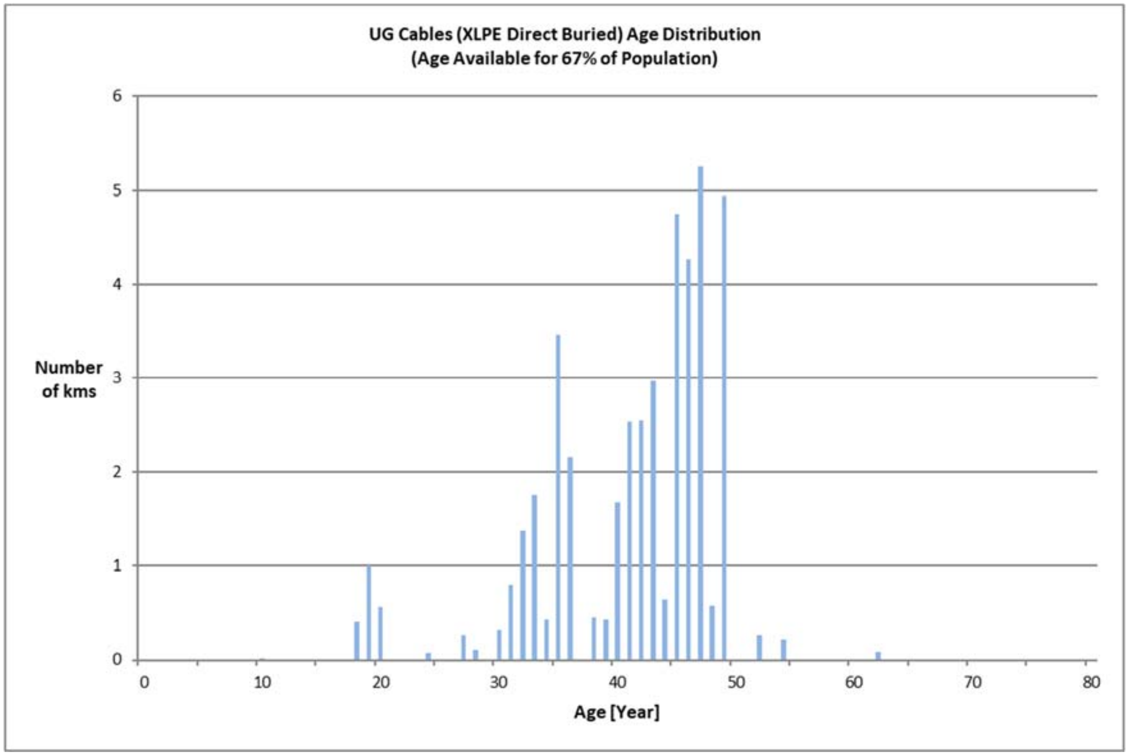

Figure 7-4 XLPE Direct Buried Cables Age Distribution

XLPE In-Duct Cables

The average age was 17 years / conductor-km. The age distribution for this asset category was as follows:

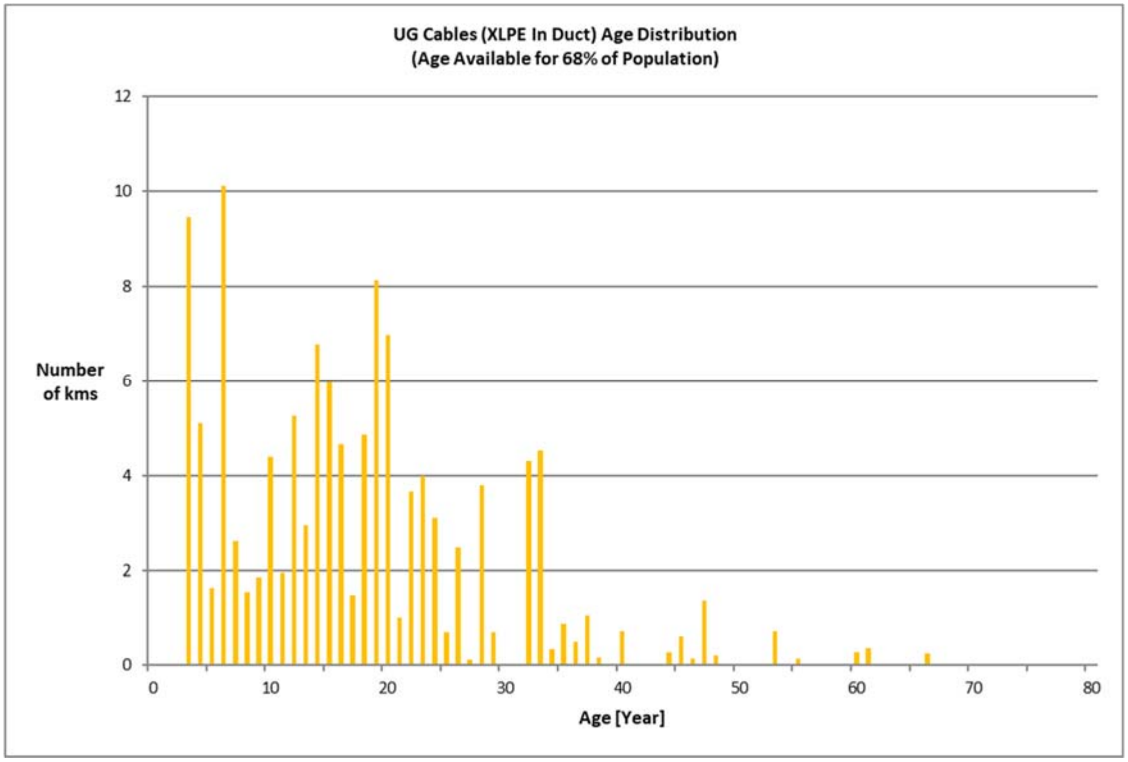

Figure 7-5 XLPE In-Duct Cables Age Distribution

PILC Cables

The average age was 81 years / conductor-km. The age distribution for this asset category was as follows:

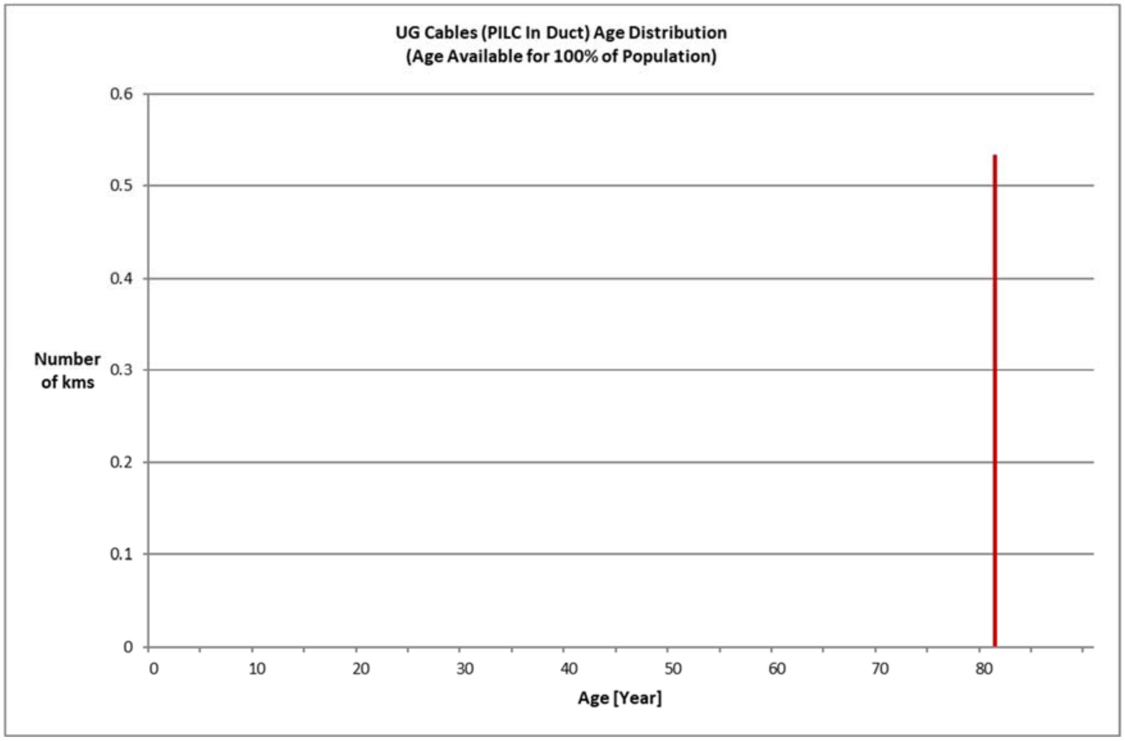

Figure 7-6 PILC Cables Age Distribution

7.3. Health Index Results of Underground Cables

XLPE Direct Buried

Among 66 conductor-km of XLPE Direct Buried Underground Cables, a total of 44 conductor-km had at least basic data for a Health Indexing.

The average Health Index for this asset group was 32%. About 70% of population was in “poor” or “very poor” condition.

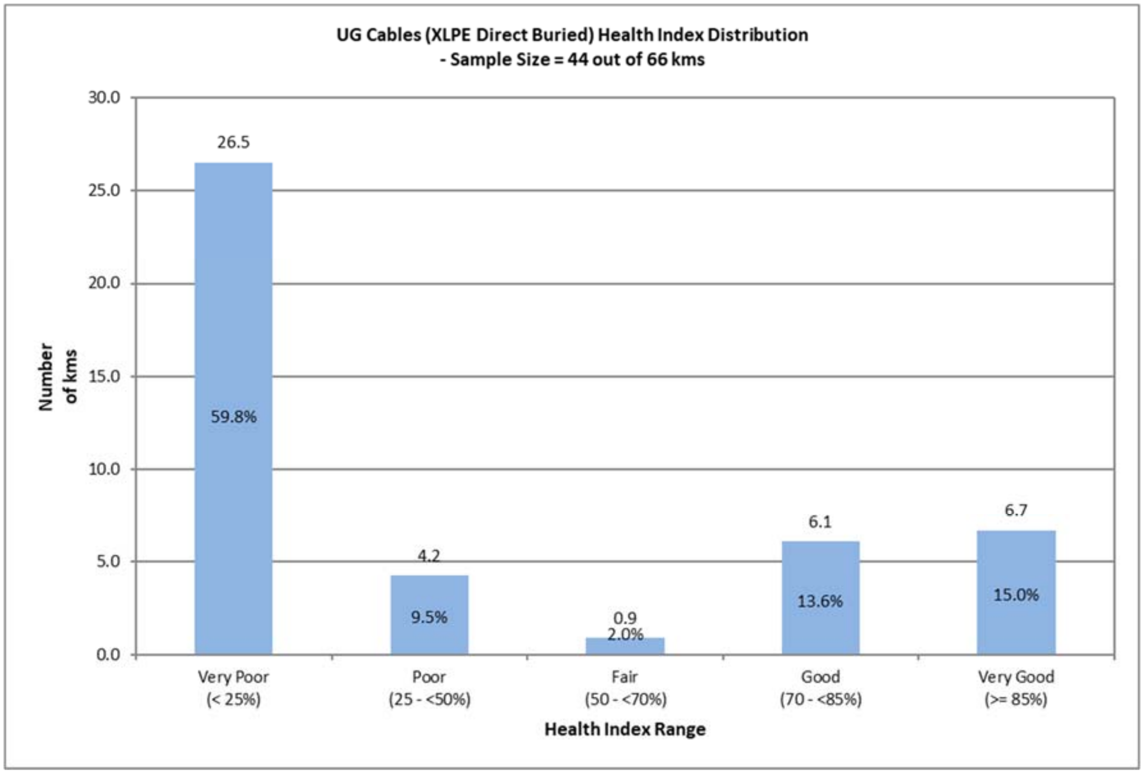

Figure 7-7 XLPE Direct Buried Cables Health Index Distribution

XLPE In-Duct Cables

Among 180 conductor-km of XLPE In-Duct cables, a total of 122 conductor-km had at least basic data for a Health Indexing.

The average Health Index for this asset group was 97%. Approximately 4% of population was in “poor” or “very poor” condition.

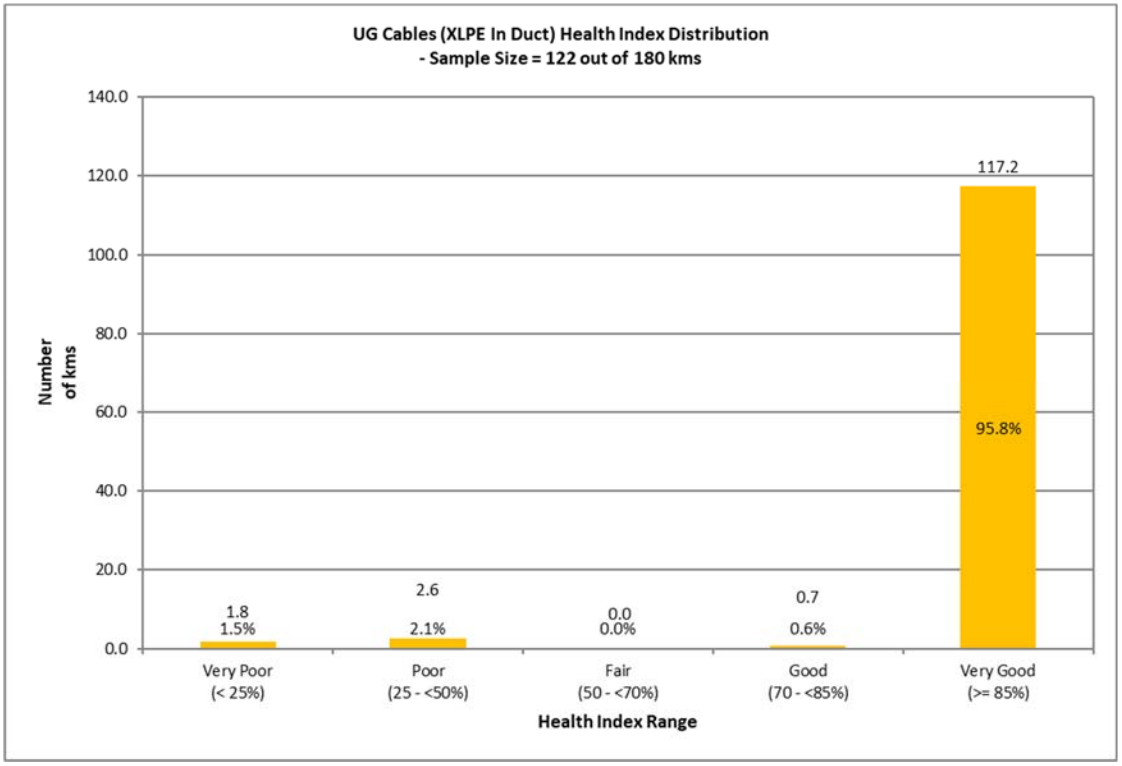

Figure 7-8 XLPE In-Duct Cables Health Index Distribution

PILC Cables

Among 0.5 conductor-km of PILC cables, all had at least basic data for a Health Indexing.

The average Health Index for this asset group was 0%. All the population was in “very poor” condition.

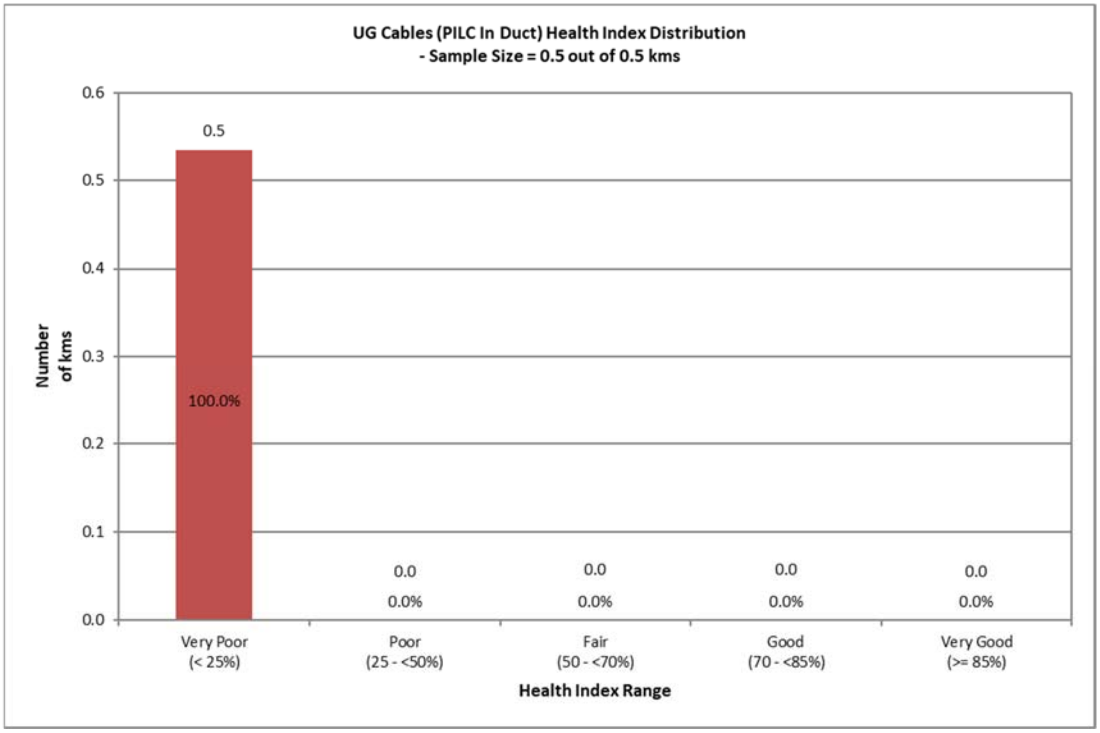

Figure 7-9 PILC Cables Health Index Distribution

7.4. Condition-Based Flagged-for-Action Plan of Underground Cables

As it is assumed that XLPE In-Duct and PILC Underground Cables were reactively replaced, the flagged-for-action plan was based on the asset failure rate, f(t).

It is assumed that XLPE Direct Buried Underground Cables were both proactively and reactively replaced, in the sense that BWP conducts proactive maintenance and replaces some portion of population before they fail. Therefore, the flagged-for-action plans shown in Figure 7-10 and Figure 7-11 below are based on the cable failure rate f(t), i.e. *reactive* replacement, with the understanding that some of the cables will actually be replaced *proactively*.

XLPE Direct Buried Cables

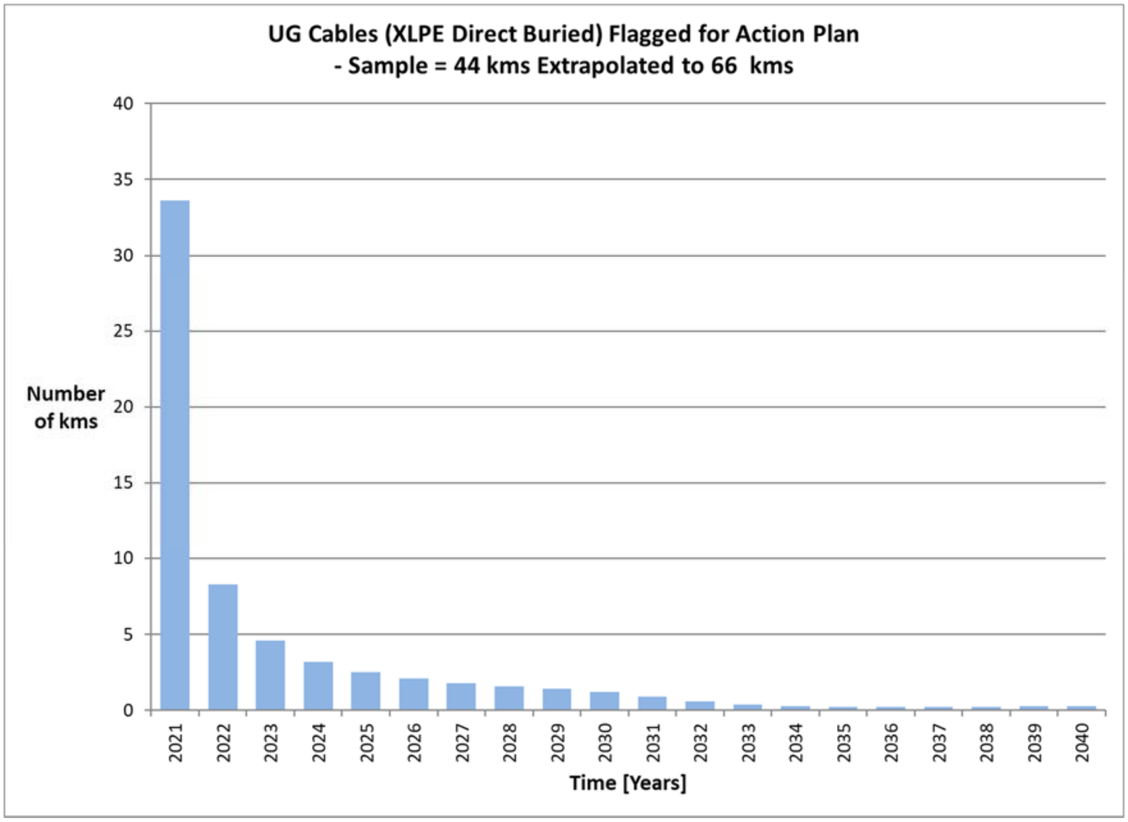

Figure 7-10 XLPE Direct Buried Cables Condition-Based Flagged-for-Action Plan

XLPE In-Duct Cables

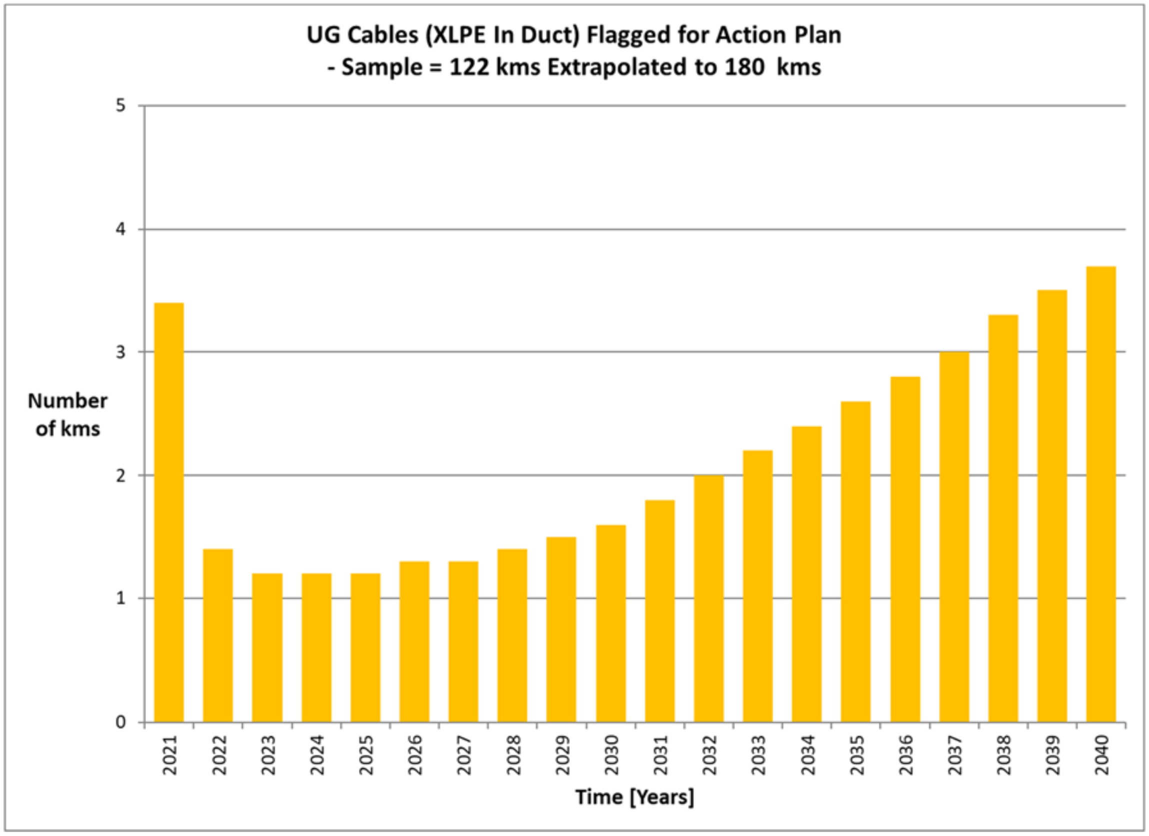

Figure 7-11 XLPE In-Duct Cables Condition-Based Flagged-for-Action Plan

PILC Cables

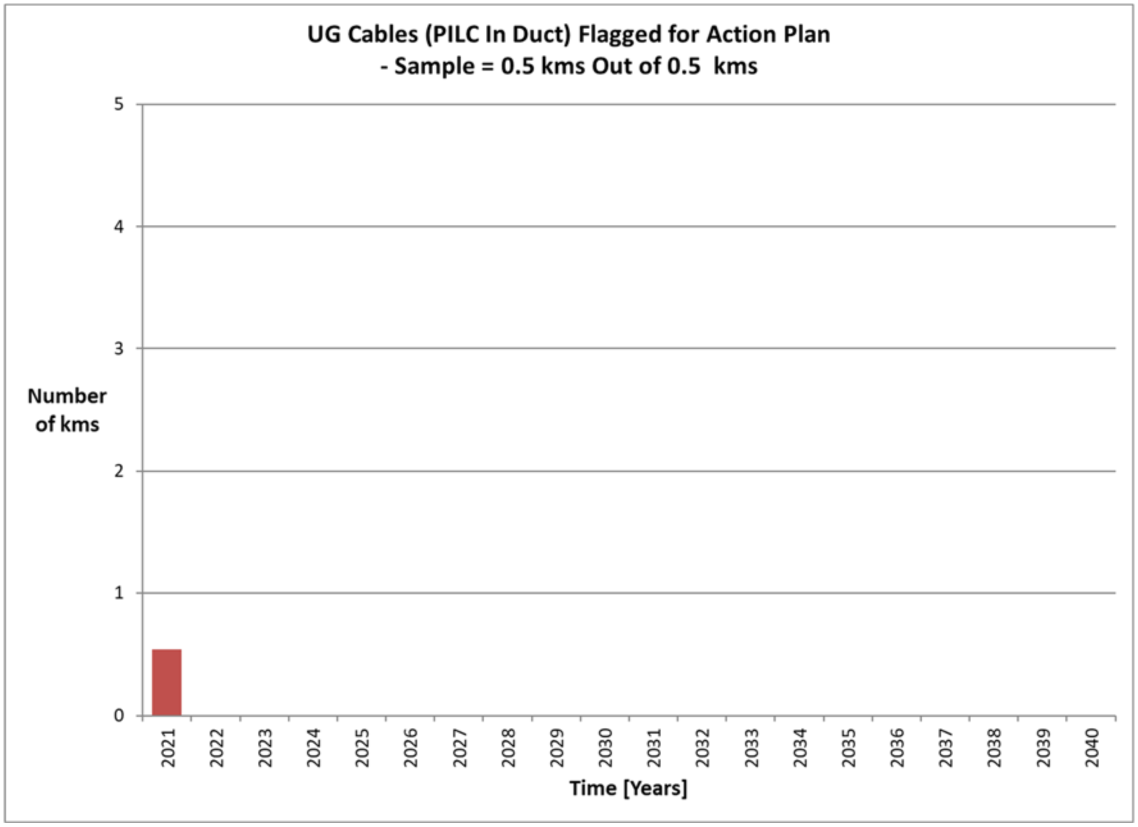

Figure 7-12 PILC Cables Condition-Based Flagged-for-Action Plan

7.5. Data Analysis of Underground Cables

The condition data for this asset category included age only.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

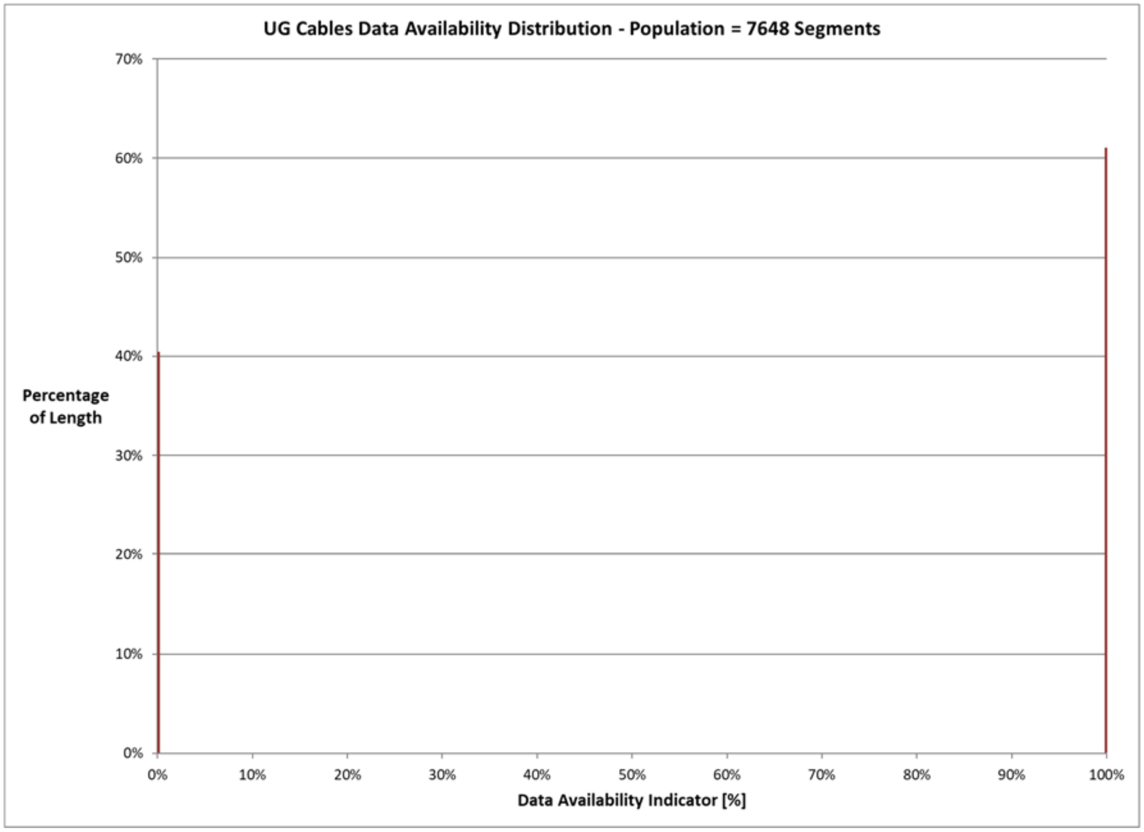

Figure 7-13 Underground Cables Data Availability Distribution

Among the three types, the average data availabilities by length were 67%, 68% and 100% for XLPE Direct Buried, XLPE In-Duct and PILC Underground Cables respectively.

Data Gap

The following table summarizes the data gaps for Underground Cables.

Table 7-5 Data Gaps for Underground Cables

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splice & Termination	Physical Condition	☆☆	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		☆☆	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record
Loading	Operation Condition	☆☆☆	Cable segment	Loading History: e.g. hourly peak Loads	Operation record

8. PAD MOUNTED TRANSFORMERS

8.1. Health Index Formula of Pad Mounted Transformers

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

8.1.1. Condition and Sub-Condition Parameters

Table 8-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	1	Table 8-2
2	Connection and Insulation	2	Table 8-3
3	Service Record	6	Table 8-4
	Age Limiter*		Figure 8-1

* Age limiter sets the maximum HI a unit can reach based on its age

Table 8-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Rust	1	Table 8-5

Table 8-3 Connection and Insulation Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Oil Leak	4	Table 8-5
2	Connectors	2	Table 8-5
3	Arrester	1	Table 8-5
4	Insulator	2	Table 8-5
5	Bushings	2	Table 8-5
6	Elbows	1	Table 8-5

Table 8-4 Service Record Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	1	Table 8-6

8.1.2. Condition Parameter Criteria

Visual Inspections

Table 8-5 Visual Inspection Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on BWP Inspection Database as below:

	Score (by Defect)		
Year	0	4	**Weight**
2020	No	Yes	1
2019			0.9
2018			0.8
2017			0.7
2016			0.6
2015			0.5
2014			0.4
2013			0.3
2012			0.2
2011			0.1

Inspection count = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Overall Condition

Table 8-6 Overall Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where overall count is calculated based on overall risk rating count as below:

	Score (by overall Risk rating)					
Year	0	1	2	3	4	**Weight**
2020	Green	Blue	Yellow	Orange	Red	1
2019						0.9
2018						0.8
2017						0.7
2016						0.6
2015						0.5
2014						0.4
2013						0.3
2012						0.2
2011						0.1

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Age

In the case of Pad Mounted Transformers, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 50 and 65 years the probability of failures (P_f) for Pad Mounted Transformers are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 8-1.

Table 8-7 Age Limiting Curve Parameters - Pad Mounted Transformers

Asset Type	α	β
Pad Mounted Transformers	**58.18**	**9.90**

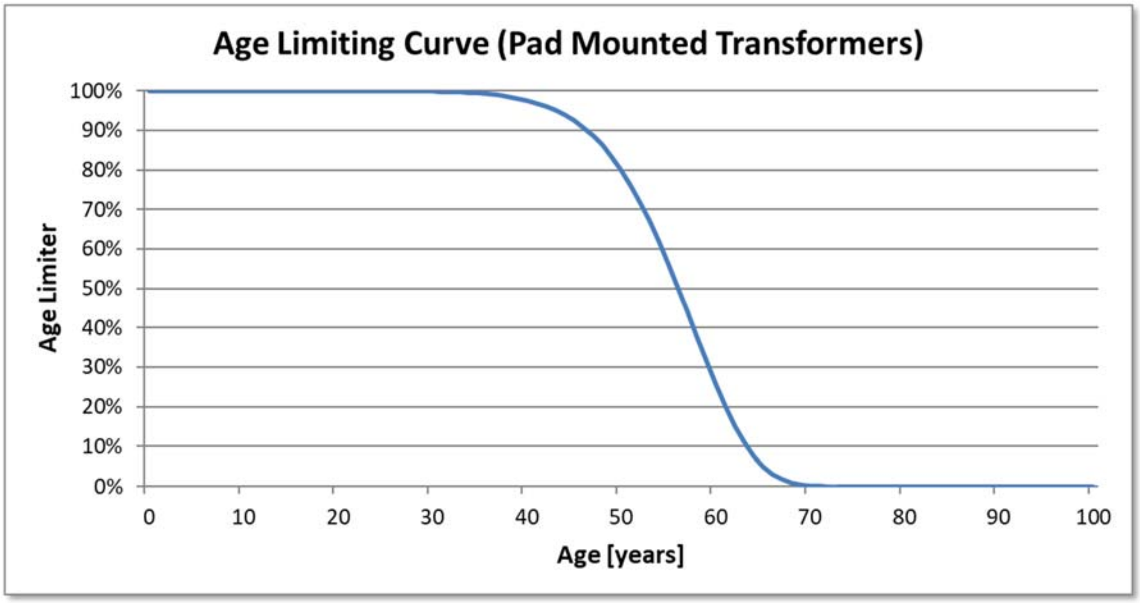

Figure 8-1 Pad Mounted Transformers Age Limiting Criteria

8.2. Age Distribution of Pad Mounted Transformers

The age distribution for this asset class was as follows:

Single Phase Pad Mounted Transformers

The average age for single phase Pad Mounted Transformers was 28.

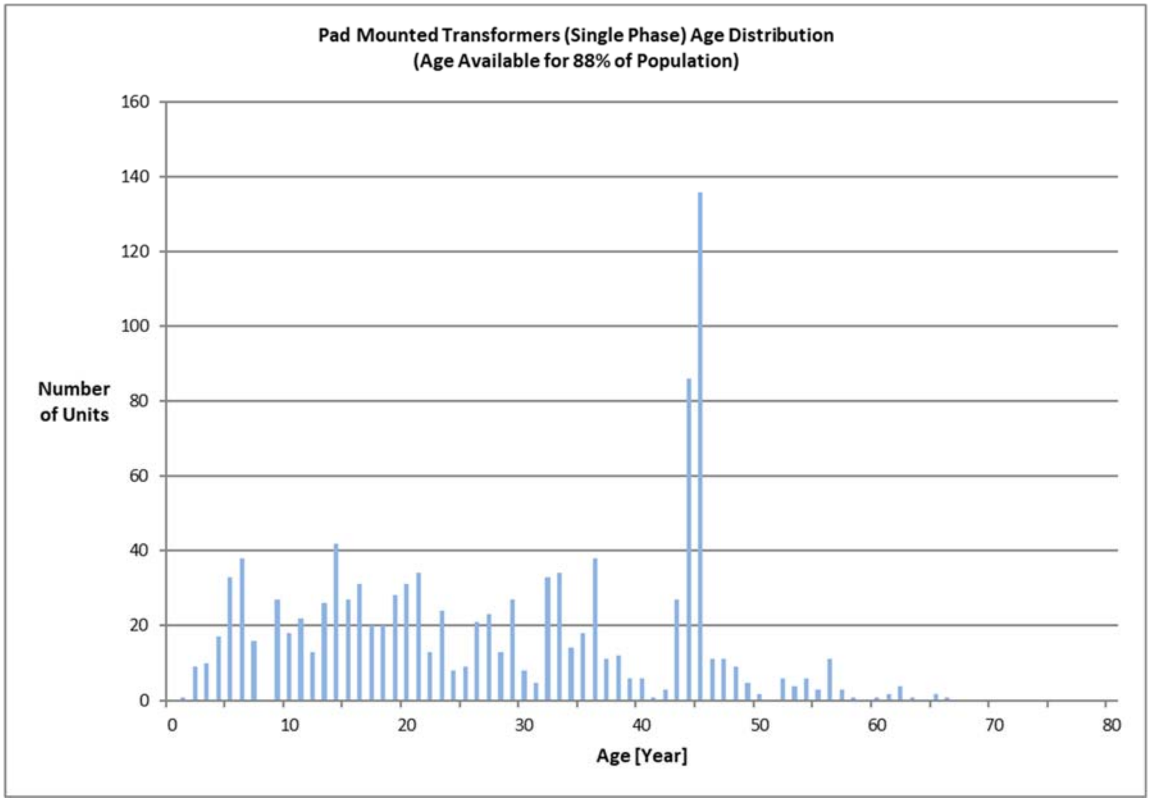

Figure 8-2 Single Phase Pad Mounted Transformers Age Distribution

Three Phase Pad Mounted Transformers

The average age for three phase Pad Mounted Transformers was 28 years.

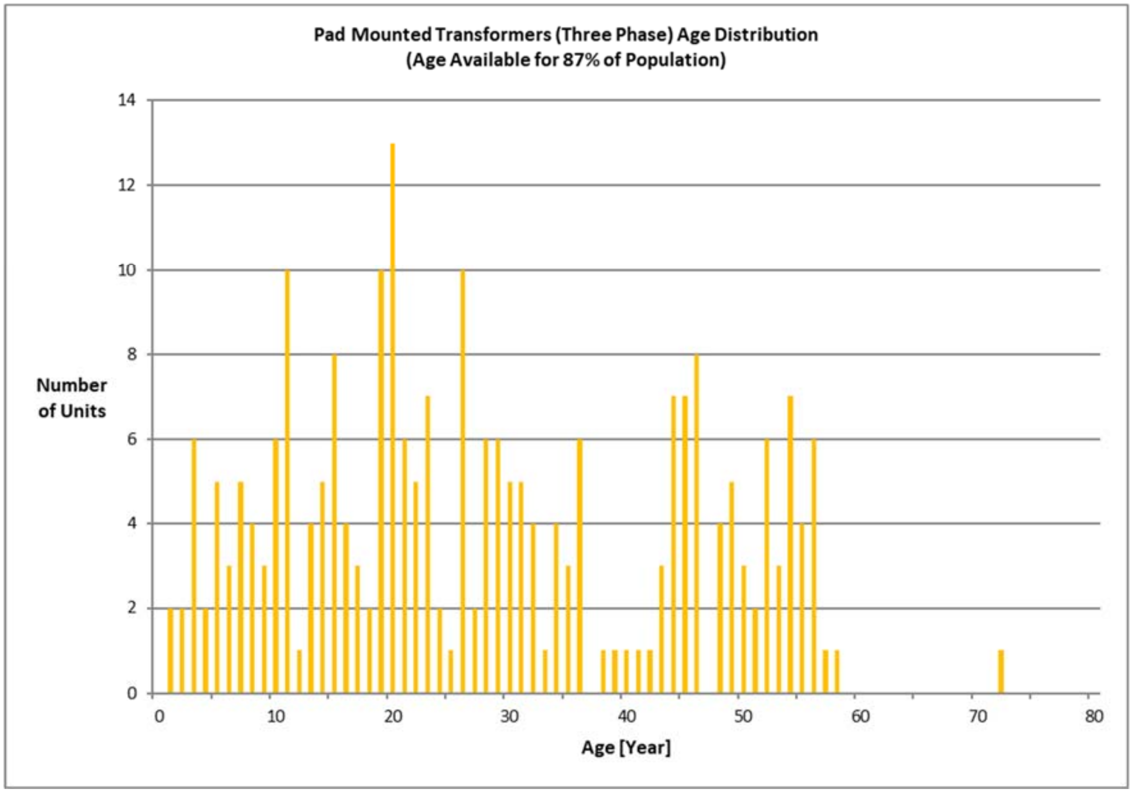

Figure 8-3 Three Phase Pad Mounted Transformers Age Distribution

8.3. Health Index Results of Pad Mounted Transformers

Single Phase Pad Mounted Transformers

There were 1272 single phase Pad Mounted Transformers at BWP. All the units had at least basic data for a Health Indexing.

The average Health Index for this asset category was 95%. About 2% of the samples were in “poor” or “very poor” condition.

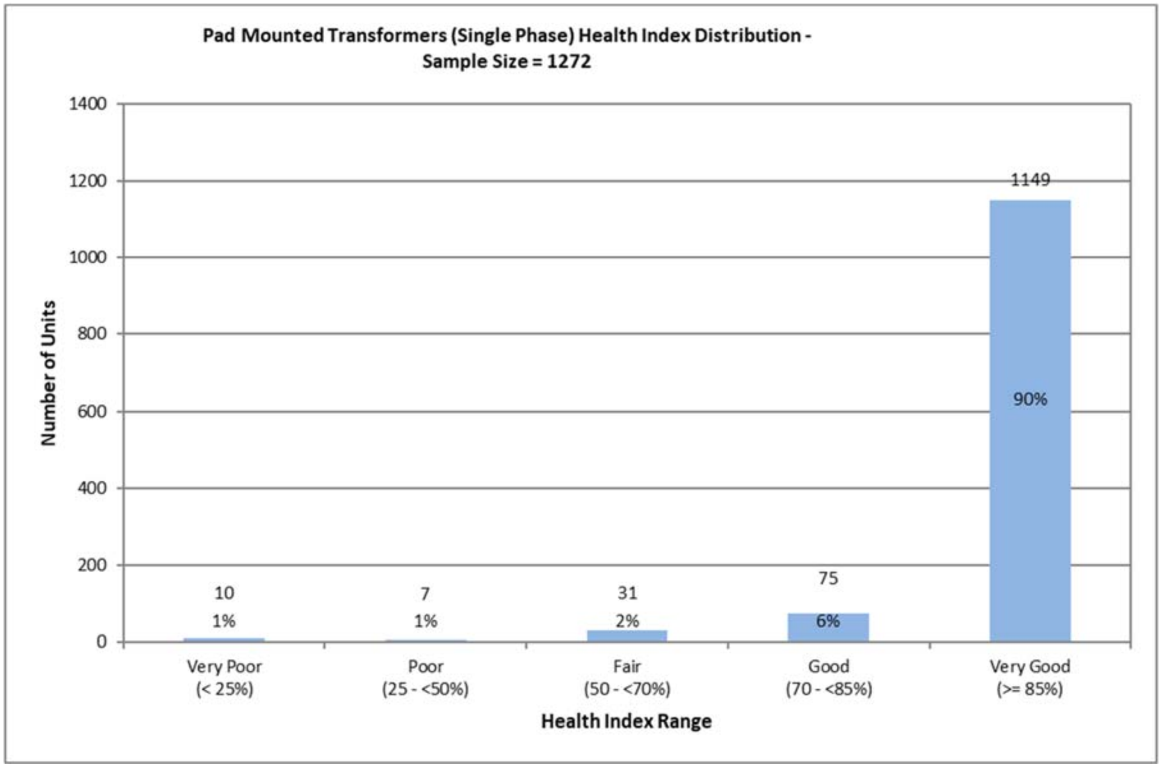

Figure 8-4 Single Phase Pad Mounted Transformers Health Index Distribution

Three Phase Pad Mounted Transformers

There were 281 three phase Pad Mounted Transformers at BWP. Of these, there were 279 units with sufficient data for a Health Indexing.

The average Health Index for this asset group was 93%. About 1% of the samples were in “poor” or “very poor” condition.

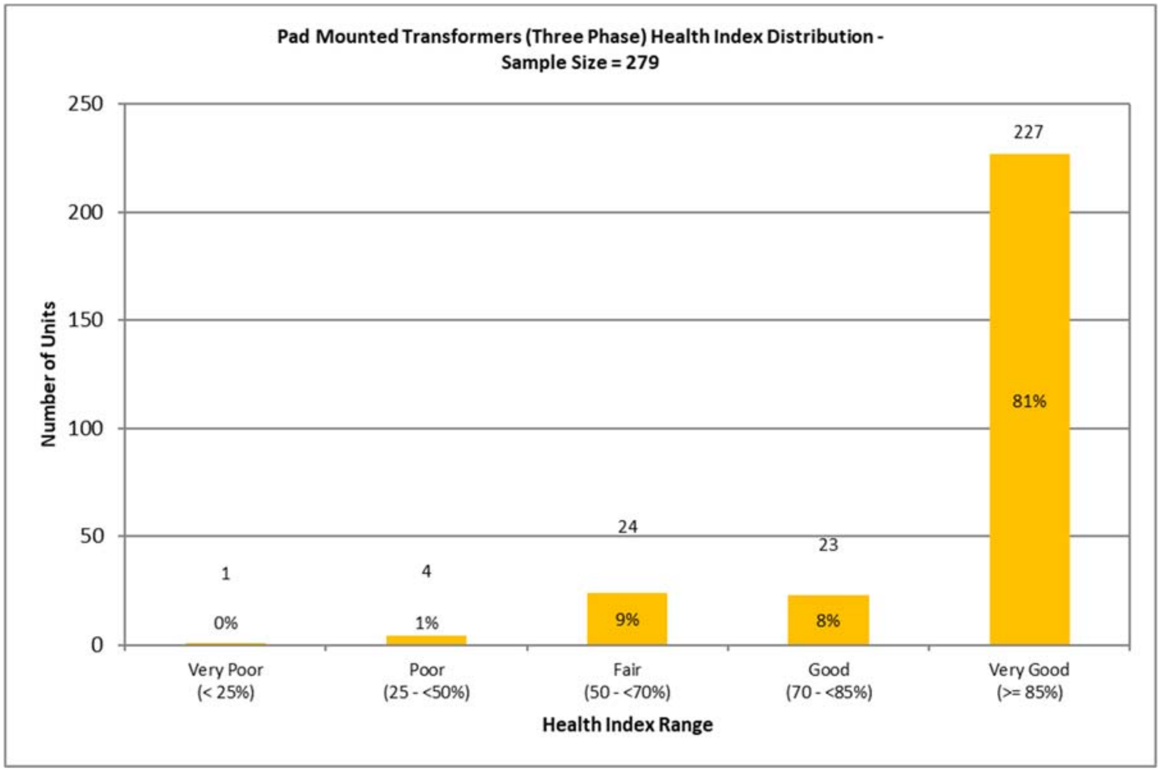

Figure 8-5 Three Phase Pad Mounted Transformers Health Index Distribution

8.4. Condition-Based Flagged-for-Action Plan of Pad Mounted Transformers

The number of units that are estimated to fail was based on the failure rate.

Single Phase Pad Mounted Transformers

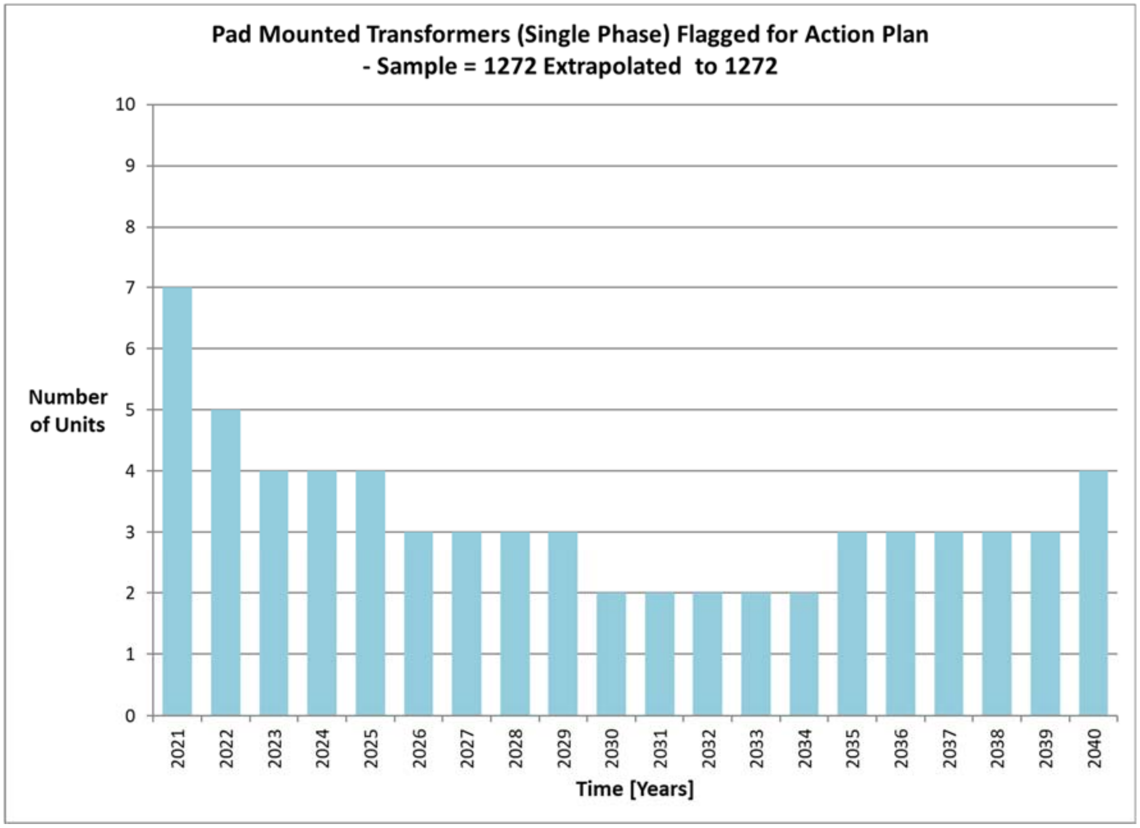

Figure 8-6 Single Phase Pad Mounted Transformers Condition-Based Flagged-for-Action Plan

Three Phase Pad Mounted Transformers

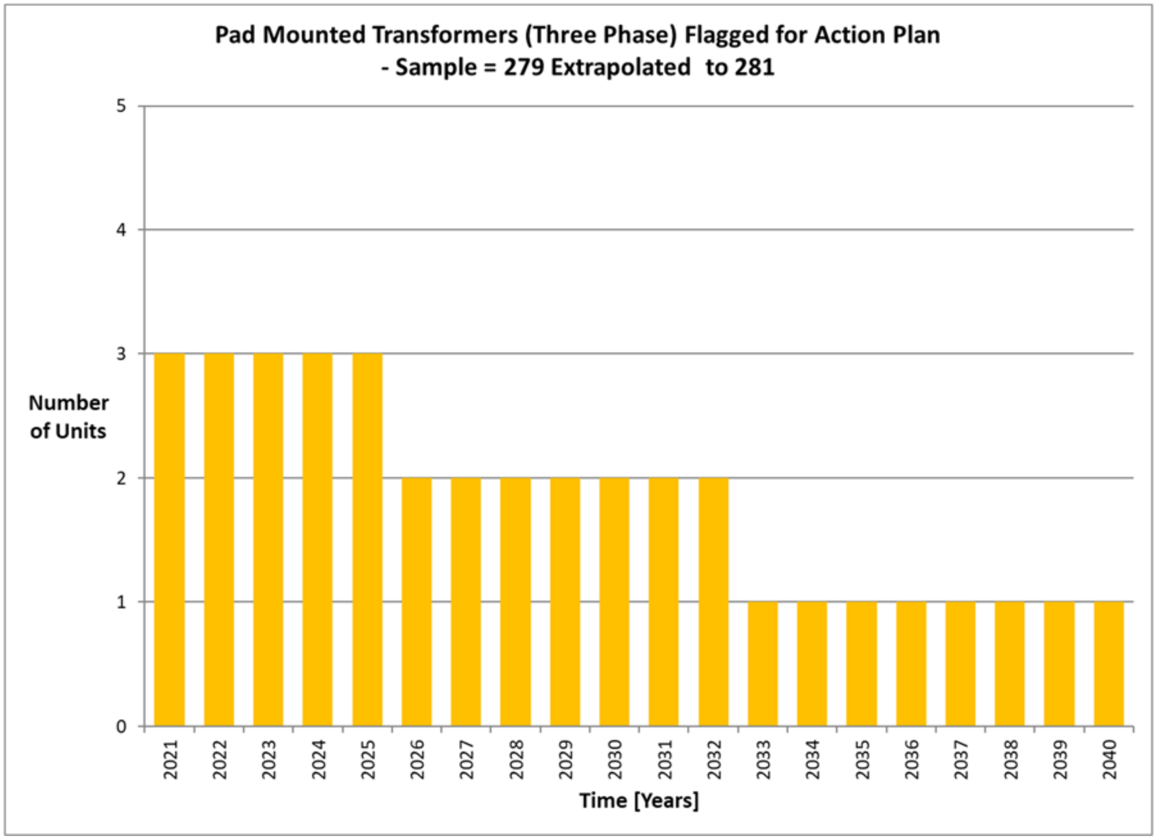

Figure 8-7 Three Phase Pad Mounted Transformers Condition-Based Flagged-for-Action Plan

8.5. Data Analysis of Pad Mounted Transformers

The condition data for this asset category included inspection data and age.

Data Availability Indicator

The data availability distribution for this asset class was as follows.

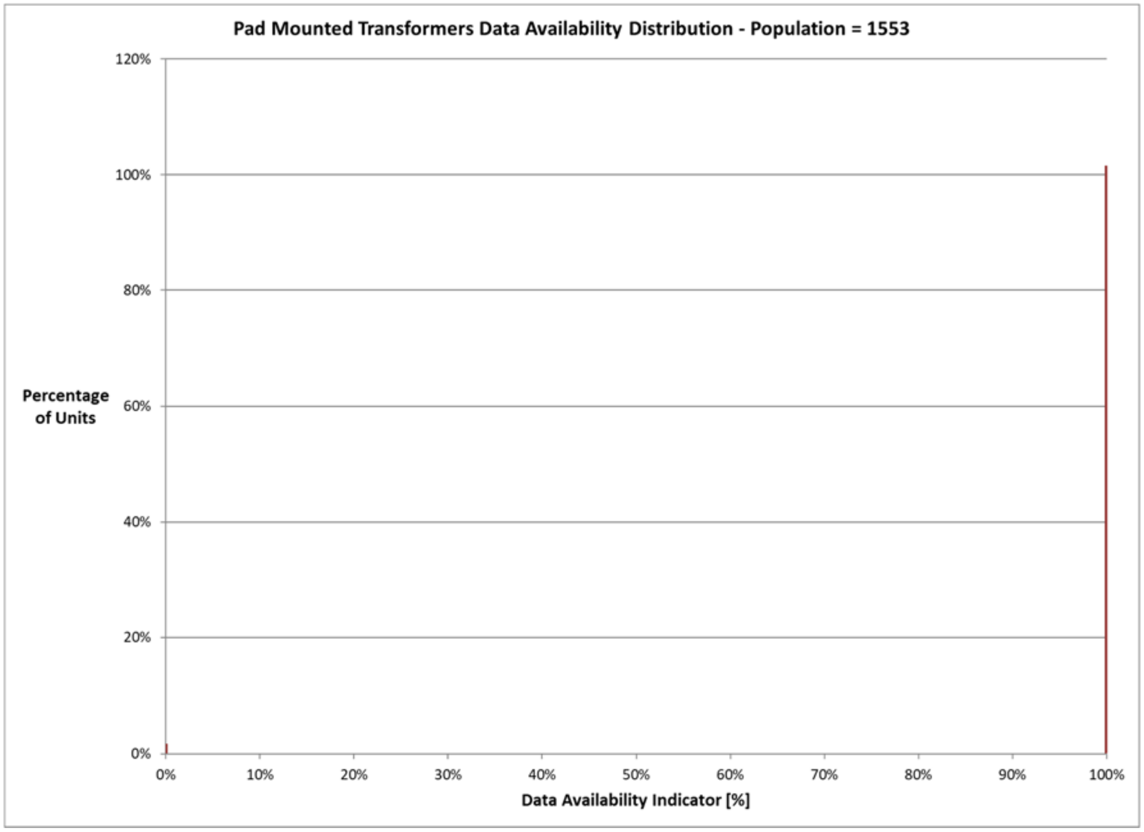

Figure 8-8 Pad Mounted Transformers Data Availability Distribution

Among the two types, the average data availabilities were 99% and 97% for single phase and three phase Pad Mounted Transformers, respectively.

Less than 1% of the population (2 out of 1553 units) did not have any data for assessment.

There were about 88% of the population (1366 out of 1553 units) having the information of “Age”.

Data Gap

The following table summarizes the data gaps for Pad Mounted Transformers.

Table 8-8 Data Gaps for Pad Mounted Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Grounding	Connection & Insulation	☆	Transformer tank	Poor grounding wire connection	Visual inspection
Base		☆	Transformer foundation	Erosion	Visual inspection
Loading	Service Record	☆ ☆	Transformer load	Loading History: e.g. hourly peak loads	Operation record

9. PAD MOUNTED SWITCHGEAR

9.1. Health Index Formula of Pad Mounted Switchgear

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

9.1.1. Condition and Sub-Condition Parameters

Table 9-1 Pad Mounted Switchgear Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	6	Table 9-2
2	Switch/Fuse Condition	3	Table 9-3
3	Insulation	3	Table 9-4
4	Service Record	8	Table 9-5
	Age Limiter*		

* Age limiter sets the maximum HI a unit can reach based on its age

Table 9-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Paint Condition	1	Table 9-6

Table 9-3 Switch/Fuse Condition Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Elbow	2	Table 9-7
2	Connection	1	Table 9-7
3	Grounding	1	Table 9-7
4	Switch	3	Table 9-6
5	Arc Suppressors	1	Table 9-6

Table 9-4 Insulation Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Support Insulators	1	Table 9-6
2	Bus Insulators	1	Table 9-6

Table 9-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	1	Table 9-8

9.1.2. Condition Criteria

Individual Component Grading

Table 9-6 Component Grading Condition Criteria

Condition Rating	CPF	Grading Description
A	4	Good
B	3	Visual Good
C	2	Fair
E	0	Poor

Individual Defect Count

Table 9-7 Individual Defect Count Criteria

Condition Rating*	CPF	Defect Count
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where defect count is calculated based on calculation as below:

Year	Defect Score		Weight
	0	4	
2020	No (There is no defect)	Yes (There is defect)	1
2019			0.9
2018			0.8
2017			0.7
2016			0.6
2015			0.5
2014			0.4
2013			0.3
2012			0.2
2011			0.1

Defect count = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Overall Condition

Table 9-8 Overall Condition Criteria

Condition Rating*	CPF	Overall Count
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where overall count is calculated based on overall risk rating count as below:

Year	Score (by overall Risk rating)					Weight
	0	1	2	3	4	
2020	Green	Blue	Yellow	Orange	Red	1
2019						0.9
2018						0.8
2017						0.7
2016						0.6
2015						0.5
2014						0.4
2013						0.3
2012						0.2
2011						0.1

Inspection count = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the inspection was conducted

Age

In the case of Pad Mounted Switchgear, age was used as a limiting factor to reflect the degradation of asset unit as time passed by. The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution, as shown in Equation 1-1 in section 1.1.2.

Assuming that at the ages of 30 and 45 years the probability of failures (P_f) for Pad Mounted Switchgear are 20% and 95% respectively in the cumulative POF curve. The calculated age limiter curve is shown in Figure 9-1.

Table 9-9 Age Limiting Curve Parameters - Pad Mounted Switchgear

Asset Type	α	β
Pad Mounted Switchgear	**37.92**	**6.41**

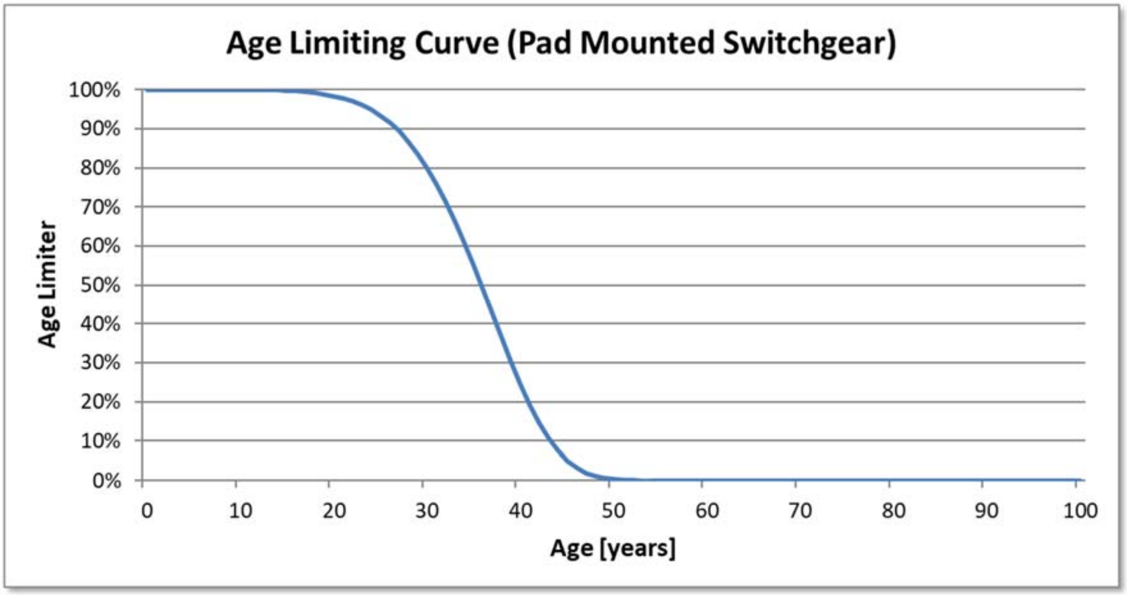

Figure 9-1 Pad Mounted Switchgear Age Limiting Criteria

9.2. Age Distribution of Pad Mounted Switchgear

The average age of all units was 15 years.

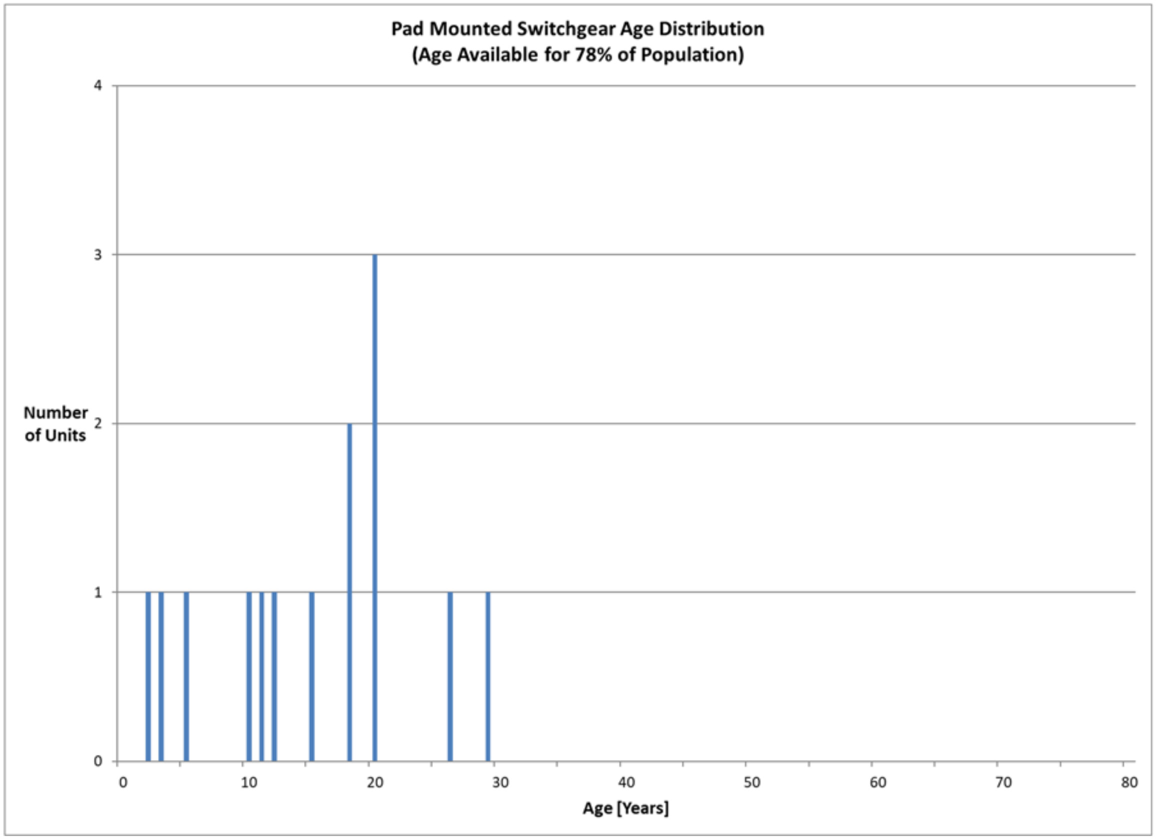

Figure 9-2 Pad Mounted Switchgear Age Distribution

9.3. Health Index Results of Pad Mounted Switchgear

There were 18 Pad Mounted Switchgear at BWP. All of them had at least basic data for a Health Indexing.

The average Health Index for this asset group was 88%. Only one unit was found to be in “poor” or “very poor” condition.

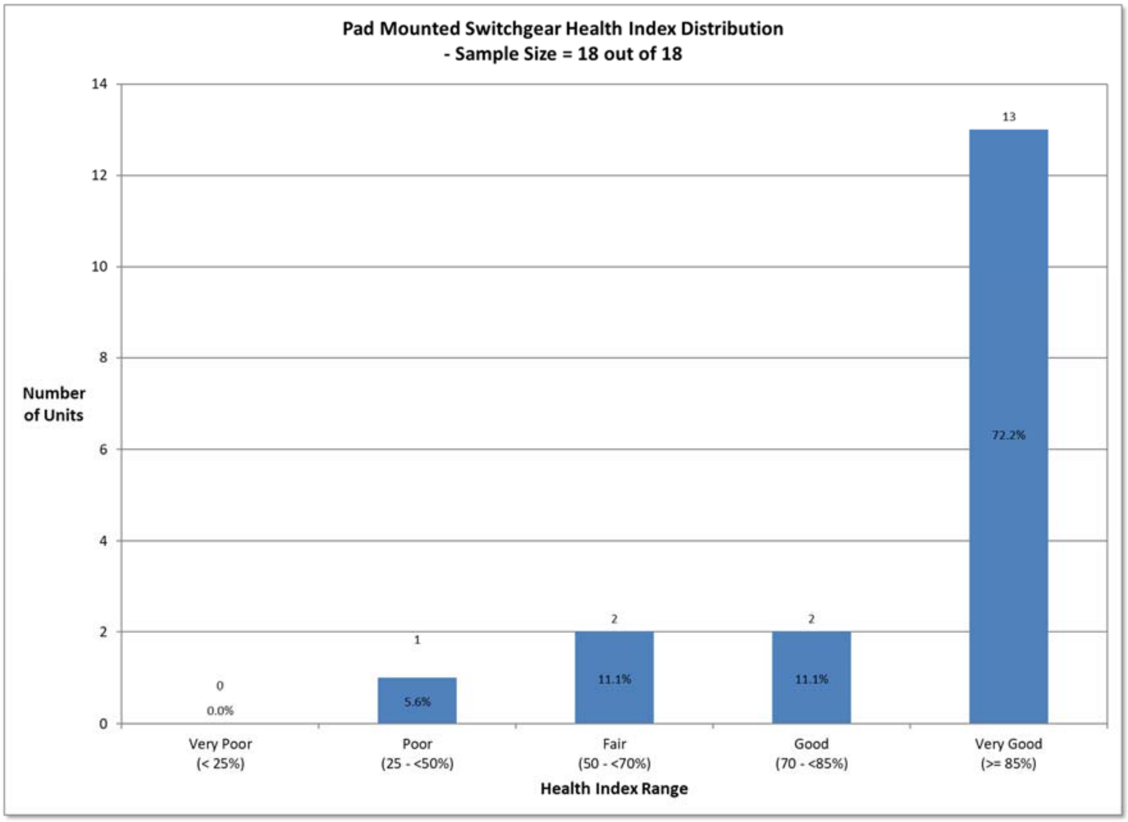

Figure 9-3 Pad Mounted Switchgear Health Index Distribution

9.4. Condition-Based Flagged-for-Action Plan of Pad Mounted Switchgear

The number of units that are estimated to fail was based on the failure rate.

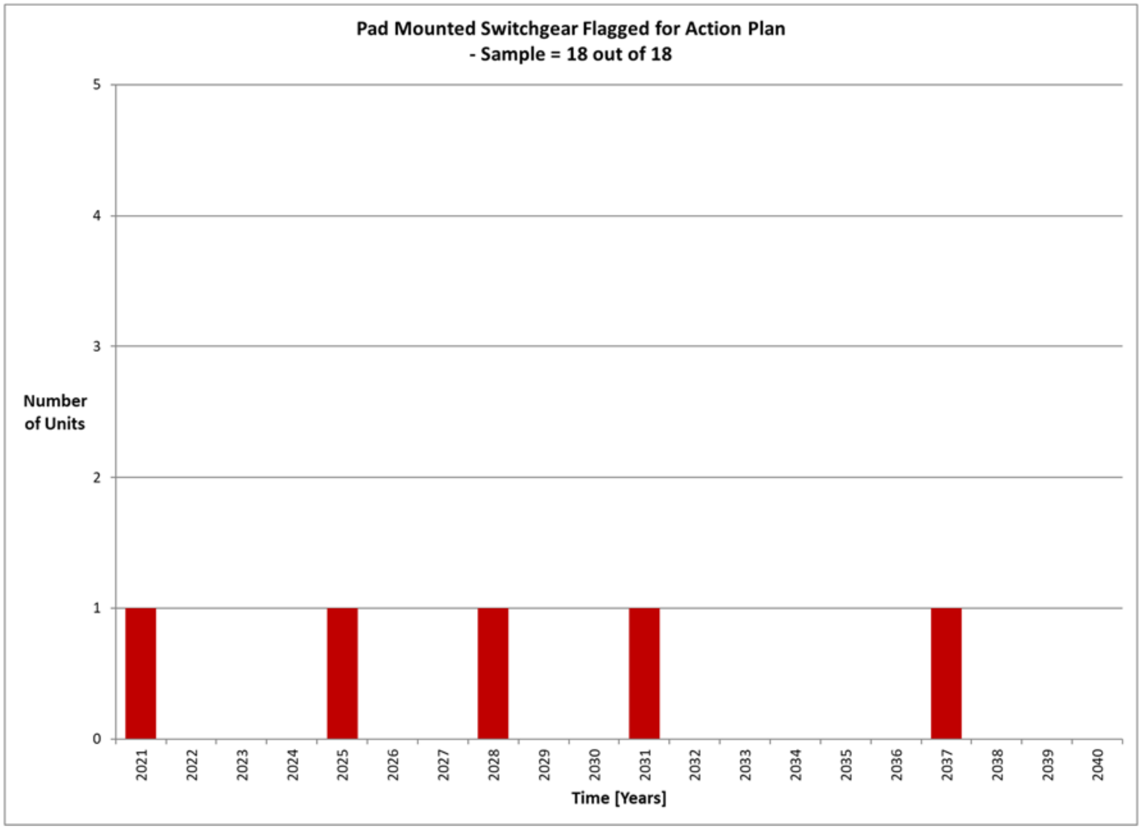

Figure 9-4 Pad Mounted Switchgear Condition-Based Flagged-for-Action Plan

9.5. Data Analysis of Pad Mounted Switchgear

The data available for this asset category included age and inspection results.

Data Availability Indicator

The average DAI was 61%. The data availability distribution for the entire population was as follows:

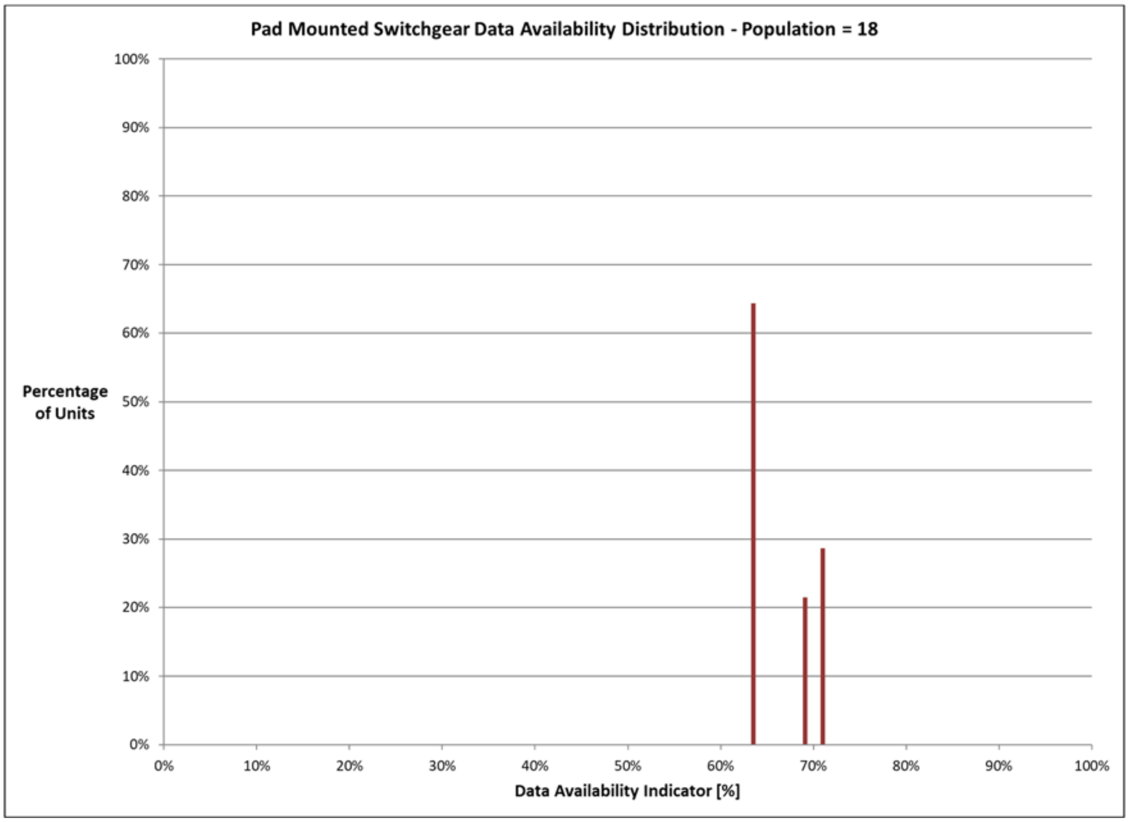

Figure 9-5 Pad Mounted Switchgear Data Availability Distribution

All units had information for assessment.

Data Gap

There was no major data gap for this asset group.

Appendix B

Asset Management Strategy

CONFIDENTIAL

BLUEWATER POWER DISTRIBUTION CORPORATION

ASSET MANAGEMENT STRATEGY

November 3, 2011

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BLUEWATER POWER DISTRIBUTION CORPORATION

ASSET MANAGEMENT STRATEGY

Prepared by: ______________________ Date: ______________

Angie Turek, P.Eng. (mm/dd/yyyy)

Reviewed by: ______________________ Date: ______________

Neil Sandford, P.Eng. (mm/dd/yyyy)

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Table of Contents

1. Bluewater Power Overview and Structure

1.1 Utility Overview

Bluewater Power Distribution Corporation (“BWP”) is a Local Distribution Company (“LDC”), regulated and licenced by the Ontario Energy Board (“OEB” or the “Board”) pursuant to licence ED-2002-0517. BWP was incorporated on October 30, 2000 upon completion of a merger of the Sarnia Hydro-Electric Commission, Petrolia Public Utilities Commission, Point Edward Public Utilities Commission, Warwick Hydro-Electric Commission, Alvinston Public Utilities Commission and Oil Springs Hydro-Electric Commission. BWP provides electrical distribution services to over 35,000 residential and commercial customers in its service area throughout Southwestern Ontario as illustrated below in Figure 1.

BWP’s mission is to maintain strong local roots while adding value as a leading energy solutions provider through innovation and partnerships.

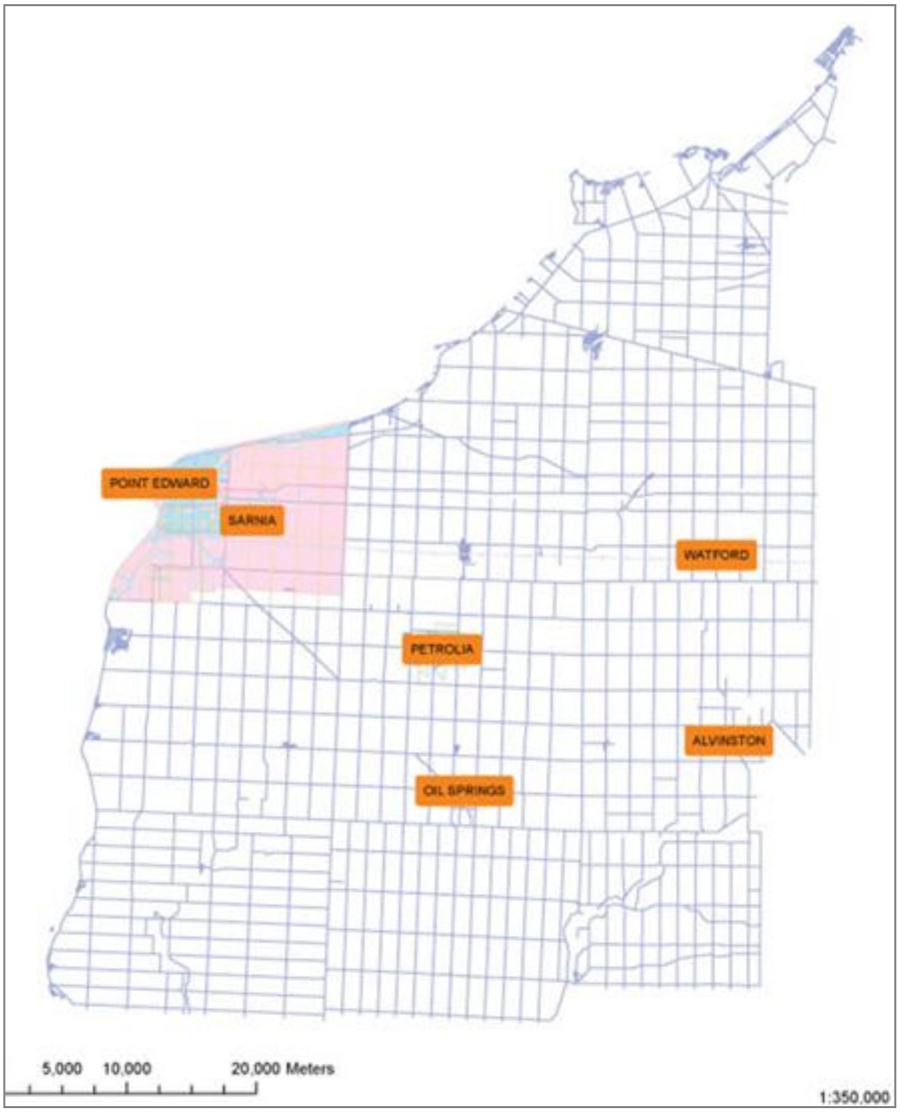

Figure 1: Bluewater Power Distribution Corporation's Service Territory

1.2 Corporate Structure

Bluewater Power Distribution Corporation is held under Bluewater Power Corporation, as illustrated in Figure 2 below.

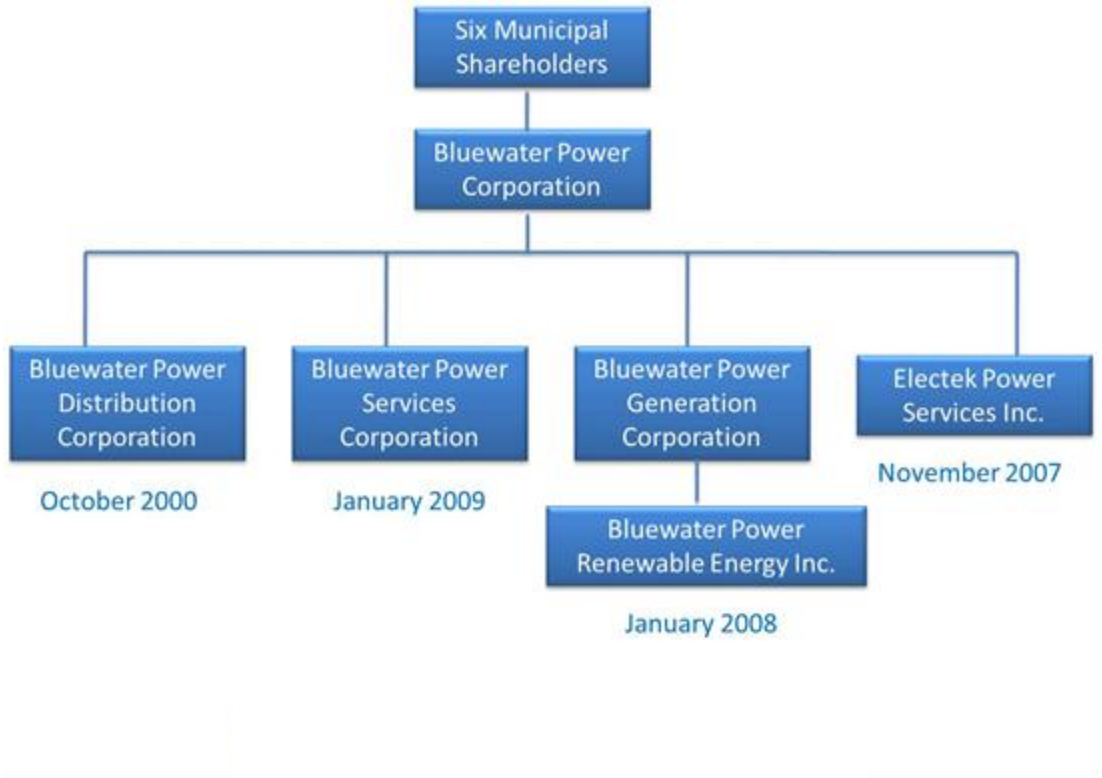

Figure 2: Bluewater Power Corporation and Affiliations

2 Corporate Values & Imperatives

BWP has established a number of corporate values and imperatives that define the organization and are considered in strategic planning:

2.1 Corporate Values

- Safety
- Customer Focus
- Community Commitment
- Integrity
- Shareholder Value
- Respect

2.2 Corporate Imperatives

Each of the strategic imperatives is internally consistent with and contributes to achieving the corporate values outlined above.

- Safety is always the first priority of the day
- Ensure high degree of reliability at all times
- Ensure prompt service restoration when power disturbances occur
- Always display respect and integrity – to our staff, customers and community
- Demonstrate strong community commitment through our outreach efforts
- Consistently strive to improve shareholder value

3 Asset Management

3.1 Overview

BWP has established many good utility practices within its inspection and maintenance programs that contribute to responsible management of its overhead and underground distribution system and substations. These practices and programs allow for continuous monitoring of the system and its performance, as well as provide opportunity for improvements to be made through capital and maintenance expenditures with minimal emergency expenditures. Combined with the formal training and/or extensive knowledge of its staff, BWP effectively and successfully manages its assets, budgets and distribution system through:

- A well-established and organized program for the patrol and condition-assessment of the distribution system (overhead and underground) and substations
- Adaptive capital replacement and maintenance programs based on inspection findings and various reporting mechanisms
- Inspection and maintenance records maintained within electronic databases (e.g. the Geographic Information System)
- Development of capital investment plans and maintenance budgets reflecting the present and anticipated health/status of the distribution system, allowing for improvements to reliability and prudent spending

3.2 Considerations

As a licenced distributor, accountable to both the Ontario Energy Board, its customers and shareholders, BWP must manage its assets while recognizing realistic service and performance goals and respecting customer expectations for the delivery of safe, reliable electricity at a reasonable price. The following considerations are critical to BWP's strategy:

- The activities should demonstrate good stewardship in the long term up-keep and growth of the distribution system, within reasonable budget considerations
- Maintenance plans should be consistent with good utility practice but capture specific items from the annual assessments and any specific customer needs
- Capital budgets should justify proposed expenditures and be flexible to respond to new priorities and extended life expectancies as defined in short and long term studies
- Service delivery should be safe, fair and consistent within all customer groups
- Annual reviews of the strategies and procedures should be a priority, creating opportunities for improved efficiencies

3.3 Risk Management

Risk management of assets is fundamental to an LDC such as BWP, aiding in the justification, prioritization and optimization of its spending, and requiring a systematic approach to assess the following with respect to each asset:

- Condition and age
- Location
- Operational data
- Maintenance

- Predictive maintenance
- Preventative maintenance
- Condition-Based maintenance (CBM)

4 Inspections and Condition Assessments

Appendix C of the OEB's DSC, which is the Minimum Inspection Requirements (the "Requirements"), outlines the intervals and minimum inspection standards pertaining to the distribution system. A definition of Patrol Inspection is also included within the Requirements. A comprehensive list of major distribution assets to be patrolled is included in Appendix C and is as follows:

- Poles and Supports
- Hardware and Attachments
- Conductors and Cables
- Switching and Protective Devices
- Capacitors
- Distribution Transformers and Switching Kiosks
- Substations
- Vegetation and Right of Way
- Civil Infrastructure
- Equipment Installations

Those assets applicable to BWP and for which a visual patrol is performed include poles (also inspected are a pole's supports and/or attachments), transformers and vaults, switching cubicles, conductors and protective devices, substations and vegetation.

Appendix C provides some guidelines while providing the LDC discretion regarding the method by which it may perform inspections of its distribution system assets. The method by which BWP structures its inspections cycles is based on dividing the service territory (Figure 1: Bluewater Power Distribution Corporation's Service Territory), supplying approximately 35,000 customers, into geographical sub-areas, a method outlined in Appendix C. These sub-areas are further identified as one of urban or rural, based on the location, relative population density and in accordance with the Board's definition of Urban[1] and Rural[2]. Furthermore, Table C-1 of the Requirements identifies the maximum intervals for visual patrols, which for most urban facilities and rural facilities is 3 years and 6 years, respectively, while stations vary between periods of months to years, depending on the type of substation. BWP's sub-areas are:

Rural

- Municipality of Alvinston
- Village of Oil Springs
- Town of Petrolia
- Watford

---

[1] **Urban** means areas with higher density and, by definition, pose safety and reliability consequences to greater numbers of people.

[2] **Rural** means those areas that are less populous suburban areas and are outside of a standard metropolitan area. Generally, rural will be defined on a circuit or sub-circuit basis by each utility, as areas with a line density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the utility might want to treat something as urban though it would otherwise be defined as 'rural' according to this definition.

Urban

- Village of Point Edward
- City of Sarnia

These regions form the basis for BWP's implementation of systematic visual patrols. Inspections are such that one-third (1/3) and one-sixth (1/6) of the urban and rural service territory, respectively, are inspected on an annual basis, thereby having inspected the whole urban and rural distribution system on a three and six-year cycle. While performed for compliance with the OEB Requirements, BWP also performs the systematic patrols for good utility practice for managing distribution system assets within these regions. For example, the patrols allow for identification and documentation of condition-related deficiencies. In addition to the routine visual patrols, there are several BWP maintenance practices that further contribute to the visual inspection and condition assessment through the implementation of specialized techniques such as thermographic imaging. Feeder inspections, insulator washing and dry-ice cleaning for example, serve as a secondary visual inspection whereby asset condition is further documented. The systematic approach of inspections, condition assessments, data analyses and maintenance allow for identification of risks to these assets. Furthermore, this approach allows BWP to mitigate risk to the assets and prioritize and support maintenance and capital expenditures, thereby improving the reliability of the distribution system through reasonable expenditures. The details of this systematic approach are documented throughout.

4.1 Patrol of the Overhead Distribution System

BWP's overhead distribution system accounts for approximately seventy-five percent of its overall distribution system. The overhead portion of the distribution system is comprised primarily of poles, conductors, distribution transformers and protective devices.

4.1.1 General Patrol

Inspection of the overhead distribution system is primarily a visual patrol whereby the inspector (a BWP System Inspection Journeyman Lineman) drives through a sub-area, visually inspecting overhead assets and surrounding vegetation to identify and assess obvious structural deficiencies and hazards. It should also be noted that deficiencies or hazards may be identified during infrared thermography or insulator washing programs, but serve as secondary or complementary patrols. Together, the primary visual patrol and secondary patrol provide adequate warning of asset deterioration and emerging hazards or deficiencies.

The table below identifies assets and their associated, conventional deficiencies that may be observed during a patrol.

ASSET	CONVENTIONAL DEFICIENCIES
Pole	Rotting, cracked, feathering, insect damage, leaning
Pole Supports & Attachments (e.g. cross arm, insulator, guying, cable guard, guy guard, etc.)	Cross Arm - Rotting, twisted Insulator – Flashed, broken, loose/tipped, down Guying – Loose, broken, anchor pulled Cable Guard – Loose, exposed conductor Guy Guard – Missing, cracked

ASSET	**CONVENTIONAL DEFICIENCIES**
Arrester	Blown, flashed
Switch	Loose, flashed, old
Grounding	Not connected, exposed ground rod
Conductor	Frayed, broken, old, tie wire broken
Transformer	Rusted, leaking
Vegetation	Overgrown, interference

Table 1: Overhead distribution system assets and conventional deficiencies associated with each

Inspections of the assets are performed with the aid of a mobile field mapping device that identifies each pole, distribution transformer and protective device within a sub-area and as depicted within the Geographic Information System ("GIS"). For each of these assets, a table exists (specific documentation methods are presented in Section 7.2 below) for documentation of asset-specific attributes, inspection records and maintenance records, including pole testing records where applicable. During the patrol, the inspector corroborates attributes specific to an asset, such as device ID, pole height, transformer size, or fuse size within a switch. Where a discrepancy exists between the GIS data and field data, the inspector documents data/attributes as found in the field during the patrol. Subsequently during the patrol, the condition of an asset, and its individual components, is observed and documented. Furthermore, an overall risk-rating is assigned by the inspector and based on guidelines developed by BWP (attached as Appendix 1). The risk-rating, a colour-coded system whereby each colour are representative of the varying degree of risk, is generally based on an assessment of potential risk to health, safety, or property of the general public, utility workers, or the environment as a consequence of failure of the asset; the risk rating also includes guidelines for allowable response times to remediate the deficiency or potential deficiency. Risk ratings are presented in Table 2 below.

Risk Rating	**Required Action**
Red	Immediate and urgent attention required; poses a risk to the general public, utility workers, property and/or the environment. Generally includes items that are broken, rotten, missing, leaking, etc.
Orange	Requires timely, corrective action to mitigate hazard to the public, employees, property and/or the environment. Generally includes items that are damaged or due for life cycle replacement.
Yellow	Maintenance will be required in 2 – 5 years
Blue	Maintenance will be required in 5 – 10 years
Green	Maintenance will be required in 11 – 20 years

Table 2: Risk Ratings

Where the inspector considers an asset's condition to pose an imminent threat to health, safety or the environment, the highest risk rating (red) is assigned and documented. Examples of such scenarios include a broken pole or a conductor lying on a cross arm. Furthermore, the inspector immediately notifies a Line Supervisor; in turn, the Line Supervisor performs a secondary on-site assessment to ascertain the condition and confirm the degree of risk. Following the visual patrol, completed assessment data is archived and maintenance is arranged as per Section 5.1 below to address the deficiency.

4.1.2 Poles

There are approximately 15,900 poles within BWP's distribution system; the majority of poles are wood of varying species while less than one percent is constructed from concrete, steel or aluminum. Annual inspection of these poles is conducted by BWP's System Inspection Journeyman Lineman during the visual patrol. As such, approximately one-third of poles in urban areas and one-sixth of poles in rural areas are inspected annually. Poles are therefore inspected on a three and six year cycle, respectively, satisfying the minimum inspection requirements of the DSC.

During the inspection, a visual assessment is performed to confirm the documented attributes of the pole. For each pole, the height, class, manufacture date, owner and pole identification number are verified. Where a discrepancy exists, the inspector documents the field attributes. Poles are subsequently inspected to determine superficial condition; that is, each pole is examined to ensure it is not broken and/or rotten, and to ensure grading around the base of the pole is adequate. Supports and attachments on the pole are also visually inspected; each component of the pole included within the inspection is noted in the table below:

Cross Arm	Terminators
Hardware	Grounding
Pins	Cutouts
Insulators	Cable Guards
Guys (Guards & Tension)	Transition Box
Conductors	Vegetation

Table 3: Pole Supports and Attachments Assessed During Inspection

Deficiencies or hazards on the pole or any one of the components above as identified during the patrol are noted to indicate that corrective action is required. The inspection table utilized during the visual patrol and for documentation of the assessment is illustrated in Appendix 2. Following the visual inspection (and testing, where appropriate as noted below) poles are assigned a risk rating within the inspection table. Rotten poles or poles that present an imminent threat to health, safety or the environment are assigned the highest risk rating. Generally, tested poles are rated either as the highest priority (red) or the lowest priority (green); however, poles may also be assigned a risk rating between these two priorities based on the assessment of other components on the pole. As noted above, where the pole's degree of risk is of the highest priority the inspector immediately notifies a Line Supervisor to initiate corrective action.

Pole testing may be conducted during the inspection, without delay, by the System Inspection Journeyman Lineman for poles that are visibly split or decayed. Furthermore, poles considered to be rotten, primarily based on age or other factors as determined by the inspector based on experience and training as a Journeyman Lineman, are also tested to ascertain condition. A resistograph is used for testing, complementing the visual assessment, measuring the degree of decay and remaining wall thickness, thereby quantifying the structural integrity of the pole. The resistograph allows for the pole identification number and test date to be documented, as well as comments the inspector may include. With the use of the resistograph, the pole test results may be produced. Consequently, the inspector is able to immediately determine the pole condition. The results of pole testing are documented by the inspector within a pole testing table, specific to the pole, and electronically by the resistograph; the results are then archived. The resistograph results (where testing was performed) are also provided to the Vice President, Operations, Line Supervisors and Foremen following the assessment and on a daily basis.

4.1.3 Conductor

Inspection of conductors is included as component of the condition assessment of poles. Furthermore, the inspection table for poles allows for the documentation of specific deficiencies or hazards typical of conductors, including broken, frayed or sagging conductor, as well as other items specific to insulation or potheads.

4.1.4 Distribution Transformers

As with poles and conductor, inspection of overhead distribution transformers is included in the visual patrol of the overhead distribution system and therefore inspected on a three-year cycle in urban areas and a six-year cycle in rural areas. Initially, attributes of both single and three phase transformers are reviewed and compared to attribute data as documented within the GIS, such as identification number, total size and primary/secondary voltages, manufacturer, phase configuration, fuse size, unit size and animal protection. The inspector documents the field attributes where a discrepancy between field and GIS attributes exist.

The condition assessment follows and applicable components of the overhead transformer (identified below) are visually inspected for deficiencies or hazards, such as corrosion or loose hardware.

Brackets	Nomenclature
Arrestors	Insulators
Bushings	Vegetation
Connectors	Animal Protection

Table 4 Transformer and Components Assessed During Inspection

Deficiencies or hazards identified during the inspection are documented. Following visual inspection the transformer is assigned a risk rating based on anticipated response time and corrective action as noted in Table 2. Where the degree of risk is of the highest priority and the transformer presents an immediate hazard to health, safety or the environment, the inspector immediately notifies a Line Supervisor to initiate corrective action; otherwise, the process for corrective action is initiated following the inspection per Section 5.1 below. Appendix 2 includes the format of the transformer inspection table utilized for documentation of the assessment during the patrol.

Overhead distribution transformers may also be inspected during infrared thermography or insulator washing of the overhead distribution system. Within each of these supplementary patrol activities any deficiencies and/or hazards that are observed are documented; this is further discussed in Sections 5.1.1 and 5.1.3.

4.1.5 Switches

Following the general practice of inspection of the overhead distribution system, switches are also inspected on a three and six year cycle within urban and rural settings, respectively. Switches on BWP's overhead distribution system include fused in-lines, air-break/load-break switches, dead-blade switches and fused switches, typical of protection for lateral feeds or for transitions between overhead and underground distribution. These individual switches are identified as a unique asset within the sub-area and included within the inspection.

As with poles and distribution transformers, the attributes of a switch are verified, including the type of switch, operating voltage, pole number on which the switch is mounted or in close proximity to, and switch identification number. A condition assessment is also visually performed of the following switch components and hardware to determine if deficiencies or hazards exist:

Lightning Arrestor	Locks
Connection	Nomenclature
Grounding	Vegetation

Table 5 Switch and Components Assessed During Inspection

Again, deficiencies or hazards that have been identified during the inspection are documented, a resultant risk rating determined and also documented within this table. Where the switch presents an immediate hazard to health, safety or the environment, the inspector immediately notifies a Line Supervisor for initiation of corrective action. Otherwise, the process for corrective action is initiated following the inspection. Appendix 2 includes the format of the switch inspection table utilized for documentation of the patrol and assessment.

Switches may also be inspected, and deficiencies/hazards documented, during annual infrared thermography or insulator washing of the overhead distribution system.

4.1.6 Vegetation

Inspection of vegetation surrounding overhead distribution assets is included as a component of the visual patrol. Within the inspection table for each of poles, transformers and switches, a line item specific to vegetation is included such that the inspector may document vegetation hazards (e.g. encroaching vegetation) surrounding the assets. The process for reporting vegetation hazards is as previously described. That is, vegetation that presents an immediate hazard is immediately brought to the attention of the Line Supervisor for initiation of corrective action. Otherwise, corrective action is initiated following completion of the inspection.

4.2 Patrol of the Underground Distribution System

BWP's underground distribution system accounts for approximately twenty-five percent of its overall distribution system. The underground portion of the distribution system is comprised primarily of pad-mount transformers, submersible transformers, transformers vaults and switching cubicles.

4.2.1 General Patrol

Similar to the visual patrol of the overhead distribution system, BWP's underground distribution system is also patrolled on a three and six-year cycle for urban and rural service areas, respectively. The patrol, performed concurrently with the patrol of the overhead distribution system, allows for inspection and condition assessment of underground assets, including pad-mount transformers, submersible transformers, transformer vaults, and switching cubicles. The process of patrolling and inspecting the underground distribution system is the same as that of the overhead inspection process; inspection of individual underground assets within a sub-area occurs simultaneously. For each transformer and protective device within a sub-area, a table exists within the mobile field mapping device for documenting asset-specific attributes, asset-specific inspection records and maintenance records. Section 7.2 below provides further information about the mobile field mapping device and documentation.

Inspection begins with confirmation of asset attributes, as identified within the GIS, such as identification number, size, primary/secondary voltages, etc. During the inspection, the condition of an asset and individual components that comprise the asset is observed; in the case of pad-mounted and submersible transformers, this entails opening the unit to observe the condition. The inspection and condition of assets is documented. Furthermore, an overall risk-rating is assigned, again based on the guidelines as attached in Appendix 1. The risk-rating is identical to that of the overhead risk rating system and is generally based on an assessment of potential risk to health, safety, the environment or property as a consequence of failure of the asset and allowable response time to remediate the deficiency or hazard. Where the degree of risk is of the highest priority (i.e. red) and the inspector considers the asset's condition to pose an imminent threat to health, safety or the environment, the inspector provides immediate notification to a Line Supervisor. Examples of such scenarios on underground distribution assets include corroded components or missing/broken safety mechanisms such as locks. The Line Supervisor, in turn, performs a secondary on-site assessment of the condition and verifies the degree of risk. Following the visual patrol, completed assessment data is archived and maintenance is arranged as per Section 5.2.6 below to address the deficiency.

4.2.2 Vegetation

Inspection of vegetation surrounding underground distribution assets is included as a component of the visual patrol. Within the inspection table for transformers, a line item specific to vegetation is included such that the inspector may identify vegetation concerns. The process for reporting vegetation hazards is as previously described. That is, vegetation that presents an immediate hazard is immediately brought to the attention of the Line Supervisor for initiation of corrective action. Otherwise, the process for corrective action is initiated following completion of the inspection.

4.3 Substations

The BWP distribution system includes eighteen (18) Distribution Stations ("DS"s) with power delivered from three (3) Transformer Stations ("TS"s), owned by Hydro One Networks Inc. ("HONI").

The 18 DSs on the BWP distribution system, also known as Municipal Stations ("MSs"), operate at a primary voltage of 27.6kV with secondary transformation to 8.32 kV or 4.16kV, supplying main feeders for wide-area distribution to residential and commercial customers. Of these, five (5) are Outdoor Open[3], four (4) are Outdoor Enclosed[4] and nine (9) are Indoor[5].

4.3.1 Inspection and Condition Assessment of Distribution Stations

BWPs Distribution/Municipal Stations, including the Outdoor Open, Outdoor Enclosed and Indoor types, are inspected at a frequency stipulated by the DSC, but at least monthly and may be inspected more frequently when time permits.

Performed by BWP's Control Room Operators (formally trained with Journeymen Linemen qualifications), an inspection and assessment of the following station components are performed:

Relay Targets	Fences
Panel Lights	Gates
Battery Volts	Structures
Battery Condition	Buildings
Transformers	Lawns/Grounds
Transformer Temperature	Fire Extinguishers
Oil Levels	Emergency Lights
Insulators	Fans/Heaters
Nomenclature	Fuse Inventory
Locks	Books/Drawings

Table 6 Substation Components Assessed During Inspection

To facilitate inspection and documentation, an assessment reporting form (attached as Appendix 3) is utilized, providing an itemized list of substation components to be assessed. Deficiencies observed, specific to the items above or other are documented; comments may also be included, elaborating on the nature of the deficiency. Following inspection, the completed assessment reporting form is reviewed by the Manager Technical Resources for BWP Distribution Corporation.

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[3] **Outdoor Open** typically refers to a station surrounded by a locked security fence. Within the station fence bare energized components operating at distribution voltage levels or higher are readily accessible.

[4] **Outdoor Enclosed** is similar to Outdoor Open however all bare live components are enclosed in locked metal enclosures.

[5] **Indoor** typically refers to a station located within a secure building. Access by the public to bare energized components within the station is prevented by the building enclosure.

5 Maintenance

General maintenance is essential to maintaining the functional integrity of the distribution system. Furthermore, such maintenance reduces overall costs, service disruptions and the need for immediate or emergency expenditures. BWP has recognized these benefits and, as such, has implemented three maintenance strategies that are applied to varying degrees on the distribution system. The strategies are defined below[6] and as follows:

A. **Predictive Maintenance** ("PdM"): activities that detect changes in the physical condition of equipment (signs of failure) in order to execute appropriate maintenance (e.g. condition-based maintenance).

B. **Preventive Maintenance** ("PM"): maintenance performed at predetermined intervals or according to prescribed criteria and intended to reduce the probability of failure.

   The primary difference between predictive and preventive maintenance is that the former monitors the condition to determine meantime to failure while the latter depends on average asset life statistics.

C. **Condition-Based Maintenance** ("CBM"): maintenance performed after indication of impending failure or degradation in performance or condition of the asset. Condition-based maintenance serves to eliminate opportunity of breakdowns and reduce deviations from optimum asset performance.

Per Appendix C of the DSC, "maintenance activities and schedules are not specified […] and are left to the discretion of the distributor […] In all cases, a distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol"[7]. The risk ratings assigned and informal prioritization of deficiencies identified during primary and predictive maintenance activities allows for timely and appropriate remediation proportional to the risk/priority identified. Generally, where inspection or predictive maintenance activities reveal a high priority deficiency (posing a threat to health, safety or the environment), remediation is urgent and condition-based maintenance is performed expeditiously, often at the time or just following identification of the deficiency. If remediation cannot be performed at such time (due to material lead times, locates, etc.), the asset is temporarily secured. Medium priority deficiencies are addressed following remediation of high priority deficiencies. However, if the deficiency may be resolved through a planned capital project, BWP will defer condition-based maintenance and continue to monitor the deficiency to ensure no subsequent degradation or failure. Low priority deficiencies are generally monitored until becoming a medium or high priority.

5.1 Maintenance of the Overhead Distribution System

The following describes the application of these strategies to BWP's overhead distribution system assets.

5.1.1 Thermographic Infrared Inspection

Infrared ("IR") thermography, a predictive maintenance practice, is performed on an annual basis by a contracted party with qualifications in this imaging technique. This non-destructive, non-invasive procedure

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[6] www.faculty.ksu.edu.sa

[7] Ontario Energy Board's Distribution System Code, Appendix C, 'Minimum Inspection Requirements', Section C.1, page 7.

measures temperatures across surrounding components of distribution assets, allowing for visualization of deficiencies prior to failure.

IR thermography is performed primarily on three-phase feeders on the overhead distribution system, but may also include single phase lines where the cause of a fault is unidentified. Thermographic imaging is also performed on switches, pothead terminations, lightning arrestors, clamp assemblies, transformers and bushings, terminal connections and conductors. Images of the deficiency, visible as a temperature variance and commonly referred to as “hot spots”, are captured and included within a report prepared by the contractor. The report (sample included as Appendix 4) also includes, for each deficiency or hazard, the location, a description of the affected component of the asset and fault severity (severe, intermediate or minor) as indicated by the temperature variance; notes and recommendations may also be included in the report.

Following thermographic imaging, the report is reviewed internally (typically by the Manager Technical Resources for BWP Distribution Corporation). Condition-based maintenance to remediate the identified deficiency is subsequently initiated through the issuance of a work order (sample attached as Appendix 5) by the Manager Technical Resources. While one work order is generally issued, two may occasionally be issued where there are numerous deficiencies in both the urban and rural areas of the distribution system. That is, one work order may be issued to remediate identified thermographic deficiencies in urban regions while another is issued for remediation in rural regions. The work order provides a general description of work to be completed, issue date, status of the work order and a settlement order, representing an internal billing account to which time and materials are charged. The work order(s) is issued to a Line Supervisor and subsequently to Journeymen Linemen, together with a copy of the report for determining location. Response time for performing condition-based maintenance to address the deficiency is generally proportional to the fault severity; that is severe deficiencies are first addressed, followed by intermediate and then minor. As such, complete failure, reduced asset performance and continued deterioration may be mitigated and/or avoided. Condition-based maintenance or asset replacement, as deemed appropriate, is performed and documented on the report and/or work order, as well as the repair/replacement date. Following remediation or replacement the report, completed work order and Equipment Change Record (sample attached as Appendix 6), if applicable, are submitted to the Line Supervisor and to the Operations & Facilities Supervisor for data entry of completed maintenance, materials and labour in the work order system. The completed work order is subsequently transferred to the GIS Administrator for data entry and updates to the GIS.

5.1.2 Feeder Inspection

Feeder inspection, another predictive maintenance practice, is performed by BWP Journeyman Lineman following an auto-reclose operation on a feeder or following a storm.

In the event of a permanent fault where an auto-recloser has exhausted operations in its attempts to clear the fault, the Control Room Operator, Line Supervisors (and stand-by, after business hours Journeyman Lineman) are notified of the event via an automatic preset message. A work order is subsequently prepared by the Operations & Facilities Supervisor (during business hours) or the Control Room Operator (after business hours) to initiate an inspection. During the inspection, the feeder on which the fault occurred is visually inspected to first determine the fault location. From the fault source, each pole, protective device and other assets along the feeder are also visually patrolled and inspected to ascertain the integrity of BWP’s assets along the pole line. The pole line is inspected for deficiencies such as split poles, loose bolts, tree limbs close to or on a line, etc. In the event a deficiency or hazard exists, a second work order may be generated to describe the nature and location of the deficiencies/hazards. Generally, BWP endeavours to remediate deficiencies or hazards to health, safety or the environment as encountered, either through condition-based maintenance or asset replacement, as deemed appropriate. There may, however, be circumstances preventing immediate remediation, for example where locates are needed to replace a pole. Until such time, BWP ensures situations such as these are temporarily secured to mitigate imperative hazards. Following remediation, the completed work order, together with an Equipment Change Record, if applicable, are submitted to the Line Supervisor. These data are then submitted to the Operations & Facilities Supervisor for data entry of completed maintenance, materials and labour in the work order system. Lastly, the completed work order is transferred to the GIS Administrator for data entry/updates to the GIS.

This process is also observed following a storm whereby a work order is issued for inspection of feeders, generally in the vicinity of the storm. The entire length of the feeder, from the substation and continuing downstream, is visually patrolled and inspected for obvious deficiencies and/or hazards. Where possible, these items are remediated upon discovery and documented on the work order. As noted above, the work order is subsequently submitted to the Operations & Facilities Supervisor and GIS Administrator for data entry in the work order system and the GIS, respectively.

5.1.3 Insulator Washing

Overhead electrical equipment is often subject to contamination from various factors such as industrial emissions, but primarily road salt spray. Of particular concern to the reliability of the distribution system is salt contamination on overhead insulators. Over time, salt accumulates and increases conductivity across the insulator; under wet conditions the conductive layer may initiate leakage current, causing flashovers and potentially resulting in a relay operation or line outage. To mitigate such contamination, reduce outages and ultimately enhance reliability, BWP utilizes the services of a contractor for insulator washing. This preventive maintenance practice occurs annually on all insulators installed on the 27.6kV distribution system. Insulator washing is initiated through the issuance of a work order by the Line Supervisor. During the washing, a condition-assessment of the insulator and other overhead assets/components along the pole line is also performed and deficiencies (such as broken/cracked insulators) are documented. The contractor, a former Journeyman Lineman, is able to identify deficiencies and evaluate the urgency of a deficiency, or the potential impact to health and safety. While all deficiencies are documented on the work order, the contractor also immediately notifies the Line Supervisor of critical/urgent deficiencies, such as a blown arrestor or broken tie wire. The Line Supervisor may also perform an on-site assessment of the deficiency or alternatively, issue another work-order and dispatch a BWP Journeyman Lineman for condition-based maintenance to immediately remediate critical deficiencies or hazards.

Following insulator washing, the Line Supervisor reviews the documented deficiencies and informally prioritizes items for corrective action. A second work order for condition-based maintenance is also issued by the Line Supervisor for remediation of these remaining, non-critical deficiencies, whereby higher priority items are first addressed, followed by lower priority items, addressing all items on the work order within approximately one month.

5.1.4 Vegetation Management

Also completed by a contractor/arborist, the preventive maintenance practice of vegetation management (also known as “tree trimming”) is performed on the overhead distribution system in both urban and rural areas on a four-year cycle. Approximately ¼ of trees in the cities of Sarnia and Pt. Edward and one municipality (of a total of four within the BWP distribution system) are trimmed annually. BWP relies on the arborist's specialized knowledge of vegetation growth rates; as such, the amount of trimming is determined by the arborist accordingly and in consideration of the cycle for this preventive maintenance program.

In addition to vegetation management performed on the pre-defined cycle, the contractor also performs demand work, that is, line clearing/tree trimming following a storm or where excess growth has been unexpectedly observed or identified during inspection of the overhead distribution system. Vegetation that has caused an outage is deemed critical and addressed immediately. Additionally, tree trimming is performed in response to customer requests to trim or remove trees in proximity to power lines. A work order is subsequently issued by the Line Supervisor, documenting the location of excess growth. Trees are then trimmed accordingly, and corrective action is so noted on the work order. BWP takes additional preventive maintenance initiatives in their vegetation management program including tree-trimming during the implementation of capital build/rebuild projects. Line-clearing and tree-trimming activities are periodically reviewed to confirm appropriate corrective action has ensued.

5.1.5 Condition-Based Maintenance

Condition-based maintenance on the overhead distribution system is performed as a result of the visual patrol/condition assessment of poles, conductors, distribution transformers and protective devices, completed by the System Inspection Journeyman Lineman, or as identified during predictive and preventive maintenance programs as noted above.

Following the routine visual patrol, data from the mobile field mapping device utilized during the inspection is extracted and inspection reports are created (sample attached as Appendix 7) whereby only those assets categorized as a red, orange or yellow risk-rating are included. The reports, prepared for poles, distribution transformers, breakers and fused switches, further highlight the specific component of the asset identified as deficient or hazardous during the inspection; additionally, comments documented by the inspector are also included for each unique asset within the reports. Reports are issued to an Engineering Design Technician for preparation of a work order for condition-based maintenance. The work order is, in turn, issued to an Operations Line Supervisor and subsequently to the Journeymen Linemen to address and remediate deficiencies identified during the routine visual patrol. Condition-based maintenance is prioritized based on the risk-rating. Generally, where inspection or predictive maintenance activities reveal a high priority deficiency (posing a threat to health, safety or the environment), remediation is urgent and condition-based maintenance is performed expeditiously, often just following identification of the deficiency. If remediation cannot be performed at such time (due to material lead times, locates, etc.), the asset is temporarily secured. Medium priority deficiencies are addressed following remediation of high priority deficiencies. However, if the deficiency may be resolved through a planned capital project, condition-based maintenance is deferred to implementation of the project and the deficiency is monitored to ensure no subsequent degradation or failure. Low priority deficiencies, aesthetic in nature, are generally monitored until becoming a medium or high priority. Remediation is performed accordingly and based on the nature of the identified deficiency. The specific corrective action taken to address the deficiency is documented on the work order. The completed work order is subsequently submitted to the Line Supervisor and to the Operations & Facilities Supervisor, the latter of which updates the work order system electronically with completed maintenance, materials and labour. The completed work order is subsequently transferred to the GIS Administrator for data entry/updates to the GIS, including work completed, the work order number and description of work; additionally, the risk rating of the asset is then reset, providing a new baseline for subsequent condition-assessments.

Condition-based maintenance to remediate deficiencies identified during thermographic infrared inspections, feeder inspections, insulator washings and routine vegetation management is performed following preparation and issuance of work orders. Remediation response time is based on the nature of the identified deficiency, as described above. The specific corrective action taken to address the deficiency is subsequently documented on the work order and, together with an Equipment Change Record if applicable, circulated between Operations (Line Supervisor and Operations & Facilities Supervisor) and the GIS Administrator for electronic data entry in the work order system and GIS respectively, as noted above. Records of condition-based maintenance, resulting from predictive and preventive maintenance programs, is also entered into the GIS for assets uniquely identified within the GIS.

5.2 Maintenance of the Underground Distribution System

Maintenance strategies on BWP's underground distribution system include predictive, preventive and condition-based maintenance practices.

5.2.1 Vault Inspection

Vault inspection, a predictive maintenance practice, is performed on a monthly basis by BWP Journeymen Linemen throughout the entire distribution system. The inspection process is based primarily on utility best practices and experience. During the inspection, vaults are assessed for water level, debris accumulation and general facility condition, such as operation of light bulbs and sump pumps; additionally, vault security is assessed for damaged lids and locking mechanisms. BWP endeavours to remediate smaller deficiencies or critical deficiencies (i.e. those presenting a hazard to health, safety or the environment) during the inspection. A work order is generally prepared for condition-based maintenance to remediate critical or high priority deficiencies. Larger or non-critical deficiencies identified during the inspection are documented and, subsequent to the inspection, compiled into a single work-order for scheduling of condition-based maintenance.

5.2.2 Subdivision Maintenance

Preventive maintenance of residential subdivision distribution pad-mount transformers is performed on an approximate seven year cycle. The program, which entails inspection and maintenance activities, is initiated through the issuance of a work order (sample attached as Appendix 8), map of the subdivision subject to maintenance and identification of transformers and the individual attributes of each (sample attached as Appendix 9) by the Manager Technical Resources for BWP Distribution Corporation. Also issued is a scope of work, developed internally and based on consultation with neighbouring utilities, utility best practice and experience. The scope of work (sample attached as Appendix 10) provides specific instructions for inspection and maintenance that are performed concurrently.

Performed by BWP's Journeymen Linemen, each transformer is removed from service and opened to verify nameplate data and attributes. Subsequently, the Journeymen Linemen execute each of the items within the scope of work.

Where a discrepancy exists between field data and information provided, the inspector documents data/attributes as existing in the field to ensure accuracy of records.

Inspection of switching cubicles is also included in subdivision maintenance and thereby performed on an approximate seven-year cyclical basis. Inspection comprises both internal and external assessment of switching cubicle components, identified below:

Internal Components	External Components
Insulators	Metal Enclosure
Arc Suppressors	Pad Foundations
Cable terminations	Latch/Mechanical Bolt
Barrier Boards	Door Hinges
Grounding	Nomenclature
Fuse Holders	
Connections	
Fault Indicators	

Table 7 Switching Cubicle Components Inspected during Subdivision Maintenance

In addition to these components, the switching cubicle is inspected for evidence of excess moisture, overheating, arcing, degradation of paint, corrosion and improper placement on the pad.

As with vault inspections, deficiencies observed during subdivision transformer and switching cubicle inspections are generally remediated at the time of inspection, including complete unit replacement where necessitated. Those deficiencies that are not remediated at the time of inspection are documented; such deficiencies are generally limited to unit replacement where spares are unavailable during inspection, or where significant time and labour is required to address the deficiency, such as painting. Following inspection the documentation from inspections and maintenance is reviewed (by the Manager Technical Resources for BWP Distribution Corporation) and a work order is issued, with estimates of labour and material costs, for subsequent condition-based maintenance. Furthermore, the Manager Technical Resources for BWP Distribution Corporation informally prioritizes remediation, based on the nature of the deficiency and impact to health, safety or the environment, and resource availability. Condition-based maintenance is subsequently performed, documented on the work order and submitted for data entry of completed maintenance, materials and labour in the work order system. Lastly, the completed work order is transferred to the GIS Administrator for data entry/updates to the GIS.

5.2.3 Transformer Lid Replacement

In 2010, all residential pad-mount distribution transformers were visually inspected to assess the condition of lids and skirts. Those transformers with lid and/or skirt deficiencies were documented, as well as the nature of the deficiency, such as corrosion. Where the transformer lid was severely corroded, exposing internal components, remediation occurred immediately through lid replacement (or temporarily secured until replacement ensued). Remaining deficiencies were then reviewed by the Manager Technical Resources for BWP Distribution Corporation and informally prioritized for remediation. A lid replacement (preventive maintenance) program has been subsequently developed whereby lids are replaced or painted to mitigate further corrosion and maintain safety.

5.2.4 Underground Cable Replacement

Generally, most underground cable was installed in the early 1970s as a result of an increase in residential, subdivision development at that time. Today, much of this cable is nearing or at its end-of-life, the consequence of which is anticipated or actual cable failures. BWP recognizes this and has implemented an underground cable replacement program to mitigate such failures and resultant decrease in performance and reliability.

The underground cable replacement program is one of both reactive and proactive measures. Prior to failure, BWP reviews its subdivisions and prioritizes cable replacements based on various factors, but primarily the age of cable and year of installation, both of which are substantial indicators of pending failure. Those of highest priority are subsequently channeled into a capital replacement program with expenditures for installing new cable; expenditures will also include the installation of duct banks for housing new cable to aid in future maintenance. While BWP proactively replaces underground cable, it also recognizes that cable may fail in the interim and, as such, also has a reactive maintenance program. For those cables that have failed, BWP splices the failed segment responsible for causing an interruption to service. The reactive approach is continued for subsequent failures, up to a maximum of approximately two to three failures, after which it is scheduled for replacement under the capital replacement program noted above.

5.2.5 Switching Cubicle Dry-Ice Cleaning

Switching cubicle contamination from dust and road salt spray may contribute to eventual dielectric breakdown and may result in tracking, short circuit and damage to the unit[8], potentially causing an outage and reducing system reliability. BWP has realized the benefits of dry-ice cleaning as a preventive maintenance practice, including prolonged service life of the unit, improved reliability and operating safety, and has therefore performed dry-ice cleaning on units with greater exposure to contaminants.

Performed by a qualified contractor, switching cubicles were cleaned with carbon dioxide (CO_2). Units were also internally and externally inspected using the guidelines for subdivision maintenance noted above. Deficiencies or hazards observed were documented and a summary report prepared (attached as Appendix 11) and provided to BWP (specifically to the Manager Technical Resources for BWP Distribution Corporation). The report is subsequently reviewed, deficiencies/hazards are prioritized and a work order issued, with labour and material cost estimates, for condition-based maintenance to remediate the identified hazards and/or deficiencies.

5.2.6 Condition-Based Maintenance

Condition-based maintenance of the underground distribution system is performed subsequent to the inspection and condition assessment, or following predictive and preventive maintenance programs noted above.

After completion of the patrol, and as with the process for the overhead system, data from the mobile field mapping device is extracted and individual asset reports are prepared. The report outlines assets that have been categorized as one of red, orange or yellow risk-ratings, based on the asset condition as assessed during the patrol. Reports prepared for transformers and switching cubicles further highlight the specific component of the asset identified as deficient or hazardous during the patrol; additionally, comments documented are also included for each individual asset. The reports are subsequently issued to an Engineering Design Technician for preparation of a work order. The work order is then issued to Operations for implementation of condition-based maintenance to remediate those deficiencies identified during the

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[8] Lindsay, Kristen: “Energized CO2 Dry Ice Blast Cleaning Firmly Grounded in the Canadian Electrical Industry”, The Electricity Forum, 1999.

patrol inspection. Condition-based maintenance is prioritized based on the risk-rating assigned; remediation is performed based on the nature of the identified deficiency. Specific corrective action taken to address the deficiency is documented on the work order. Following remediation, the completed work order is returned to the Line Supervisor and then circulated between the Operations & Facilities Supervisor and GIS Administrator for data entry in the work order system and GIS.

Condition-based maintenance to remediate deficiencies identified during predictive maintenance (i.e. vault inspections) is also performed following the preparation and issuance of work orders. Vault deficiencies are generally limited as extensive inspections and preventive maintenance was performed in 2008 and 2009 in preparation for municipal road-works and infrastructure upgrades. However, where deficiencies exist, remediation is prioritized and based on the nature of the identified deficiency. The specific corrective action taken to address the deficiency is subsequently documented on the work order and circulated between Operations (Line Supervisor and Operations & Facilities Supervisor) and the GIS Administrator for electronic data entry in the work order system and GIS respectively.

Lastly, condition-based maintenance may also be performed following preventive maintenance of subdivision transformers and switching cubicles, and following dry-ice cleaning. While BWP endeavours to leverage the outage time used for subdivision maintenance and remediate all identified deficiencies, deficiencies may exist that cannot be remediated as longer lead time for materials may be required; however, these deficiencies are documented and, as noted above, remediation is prioritized. Condition-based maintenance is subsequently performed, following issuance of a work order. Again, and as noted above, the completed work order is circulated between Operations and the GIS Administrator for electronic data entry in the work order system and GIS as applicable.

5.3 Maintenance of Substations

BWP’s maintenance practices for substations also include elements of predictive, preventive and condition-based maintenance, as described below.

5.3.1 Thermographic Infrared Inspection

Similar to the practice on the overhead distribution system, the predictive maintenance practice of IR thermography of distribution stations is performed on an annual basis and concurrently with imaging of the overhead system. Inspection is thorough and includes imaging of overhead conductors, switches and protective devices, terminations, transformers and bushings, connectors, etc. Deficiencies (‘hot spots’) and images of the deficiencies are included within the report, as described in Section 5.1.1 above, prepared by the contracted thermographic imager. As with overhead ‘hot spots’, those concerning substations are categorized and prioritized by fault severity (severe, intermediate or minor); recommendations for remediation may also be included.

The imaging report is reviewed (specifically by the Manager Technical Resources) and a work order is prepared for condition-based maintenance to remediate identified deficiencies. Response time for remediation is proportional to the fault severity to mitigate continued deterioration of asset performance or complete failure. Condition-based maintenance or asset replacement, as deemed appropriate, is subsequently performed and documented on the report and/or work order, as well as the repair/replacement date. Following remediation/replacement, the report and completed work order are submitted to the Line Supervisor and to the Operations & Facilities Supervisor for data entry of completed maintenance, materials and labour in the work order system. Lastly, the completed work order is transferred to the GIS Administrator for data entry/updates to the GIS.

5.3.2 Distribution Station Testing and Maintenance Program

Preventive maintenance of BWP's distribution stations is performed on a four-year cyclical basis such that approximately one-quarter (25%) of the DSs are maintained annually. However, preventive maintenance of DSs may also be performed during capital improvement projects, for example upgrades to a station. In such cases, the four-year cycle of maintenance of the specific station is re-established at such time.

Although termed preventive maintenance, BWP's program is comprised of inspection, testing and condition-based maintenance and is performed by a contractor. BWP has developed various scopes of work as well as some specific instructions (attached as Appendix 12 and Appendix 13 respectively) for inspection and maintenance of substations based on InterNational Electrical Testing Association (NETA) standards. BWP also relies on the expertise and experience of the contractors. The scope of preventive maintenance of DSs is specific to the substation, but generally includes inspection, electrical and/or mechanical testing (as appropriate) and maintenance of substation components identified in Table 8 below.

Transformer electrical and mechanical testing and condition analysis	Circuit breaker electrical and mechanical testing and condition analysis
High voltage cable testing	Relay testing
Ground grid testing	Switchgear assembly inspection
Potential transformer testing	Station service transformer mechanical inspection

Table 8 Inspection and Testing Activities for Distribution Station Components

Sample forms utilized during inspection, testing and maintenance are attached as Appendix 14. The forms, which establish the minimum scope for this program, allow for documentation of inspection comments as well as testing and maintenance data. Following preventive maintenance, the completed forms are submitted to the Manager Technical Resources for review of comments and aberrations. The experience of the Manager and that of the inspectors allows for categorization of high priority versus medium and low priority items, further described below in Section 5.3.3 below; it is the categorization which allows for prioritization of deficiencies and remediation response times.

5.3.3 Condition-Based Maintenance

Condition-based maintenance of DSs is performed as a result of the monthly inspection and condition assessment or as identified within the predictive and preventive maintenance programs (IR thermography and DS testing and maintenance program respectively).

As previously noted, completed forms outlining identified deficiencies are reviewed; deficiencies are then evaluated and categorized as one of high, medium or low priority. High priority represents deficiencies that present an immediate health, safety, environmental or reliability concern and therefore considered critical. Examples include a broken lock or transformer oil leak. Medium priority represents deficiencies that exist but do not compromise asset functionality. Low priority represents deficiencies aesthetic in nature that again, do not affect functionality. Generally, condition-based maintenance to address high priority deficiencies is performed during the inspection and condition assessment of distribution stations (for example replacement of a broken light bulb), or as soon as possible, allowing for material lead times for example. Until such time however, the asset is temporarily secured and so noted on the original form. The response time and nature of condition-based maintenance to address medium or low priority deficiencies varies, and is based on the priority level and nature the deficiency respectively. Medium priority deficiencies are addressed following remediation of high priority deficiencies. However, if the deficiency may be resolved through a planned capital project, BWP will channel remediation into the capital project and continue to monitor the deficiency to ensure no subsequent degradation or failure. Low priority deficiencies, aesthetic in nature, are generally monitored until becoming a medium or high priority.

Following remediation and where a work order has been issued, the completed work order is submitted to the Operations & Facilities Supervisor (for structural or facility related items) or to the Manager Technical Resources (for electrical items) for data entry of completed maintenance, materials and labour in the work order system. Lastly, the completed work order is transferred to the GIS Administrator for data entry/updates to the GIS.

Condition-based maintenance to remediate deficiencies identified during predictive maintenance (thermographic infrared inspection) is performed following preparation and issuance of work orders. Remediation is prioritized based on assigned priority level within the thermography report. The specific corrective action taken to address the deficiency is subsequently documented on the work order and provided to Operations (Line Supervisor and Operations & Facilities Supervisor) for review and for electronic data entry in the work order system. Records of condition-based maintenance, resulting from predictive maintenance programs, are also entered into the GIS for specific substation assets.

Deficiencies identified during preventive maintenance (DS testing and maintenance program) are also generally remediated at such time, to capitalize on the existing station outage and further reduce the frequency in which a station is taken out-of-service. Condition-based maintenance that cannot be performed during preventive maintenance is subsequently performed as materials are available. Again, where a work order is issued, data from the work order is transcribed to the work order system and the GIS where applicable.

6 Information Systems and Innovative Technologies

The following sections highlight the role of BWP's information systems and technologies that contribute to the effective and efficient management of its distribution assets. Many of the systems and technologies are utilized to maintain and/or extrapolate data for the purpose of managing assets and analyzing system functionality and reliability.

6.1 Load Break Switches

Through capital expenditures, BWP has installed and will continue to install remotely-controlled reclosers throughout its distribution system. The benefits of the automated reclosers that may be gained are as follows:

1. Remote switching capabilities that expedite the restoration of power
2. Fewer customers affected by outages through sectionalizing the feeder during a fault
3. Provision of fault data to allow analysis of each fault and subsequent system adjustments to improve reliability and safety
4. Coordination of reclosers with the station feeder breaker to better protect equipment and public safety
5. Remote monitoring of all electrical quantities in real-time

6.2 Smart Meters and Smart Grid

In 2009, Ontario Legislature enacted the Green Energy Act ("GEA") to facilitate, in part, renewable energy projects, promote energy conservation and encourage energy efficiency. From a Local Distribution Company's perspective, the GEA could facilitate reliability of the distribution system and reduce peak demand. Supplying electricity during peak demand has a range of impacts:

1. Electricity Costs – higher demand often means higher market prices
2. Environment – generally more 'unattractive', base-load generation, such as nuclear or coal-fired, is required to meet peak demand
3. Expenditures – investment in additional generation, transmission and distribution infrastructure is required to meet increasing demand

To facilitate a reduction in peak demand a 'smart grid[9]' may be developed that may comprise various mechanisms or technologies such as load control, self-healing feeders or Smart Meters. In 2005 BWP formed a Smart Meter team which includes representatives from each department that were involved in the Smart Meter initiative, including the Watford Smart Meter Pilot Project. The pilot project entailed installation of 750 smart meters in all the homes and businesses in Watford, beginning in October 2005. Watford was chosen as the pilot project area as BWP was able to leverage existing technologies. Specifically, a large portion of Watford customers had automatic radio read meters, which are a required component of smart meter communications technology, within a geographically self-contained 'communications neighbourhood. The primary focus of the pilot was to provide technical and functional experience to BWP staff and, as such, the project was largely transparent to the end-user i.e. the customer. While customers were not exposed to Time of Use ("TOU") pricing during the pilot project, each received information regarding their consumption patterns and the cost of power that would have been applied if the TOU pricing were in effect at the end of the pilot. Customers also received information on how to shift load so that they could take best advantage of TOU pricing once it became mandatory. The goal for 2007 was to gather enough information to allow BWP to make an educated decision on a smart meter vendor based on the 'best fit' for its customers and the utility as a whole. Information has been gathered through BWP's Watford Smart Meter Pilot, vendor information sessions, smart meter conferences, and through consultation with other utilities. Since then, BWP has been a member of a smart meter working group and has also been included in a Utility Consortium Smart Metering RFP. BWP has used the information gained from its participation to:

1. Benefit from extensive research, piloting and testing of all aspects of the initiative including vendors, security, communications, disposal of assets and workflow requirements
2. Gain knowledge necessary select a smart meter vendor that represents the 'best fit' for the utility
3. Develop accurate plans and budget forecasts for smart-meter deployments

In 2010, BWP progressed from research and investigation of options to implementation; network component were first installed, followed by smart meter installations on all residential units and commercial accounts classified as general service < 50 kilowatts. Since then, BWP continues to work with its vendor to build the

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[9] For the purpose of this document, smart grid shall mean intelligent electricity networks that can integrate user actions with innovative technologies for intelligent and secure monitoring, control and communications to efficiently deliver sustainable and secure electricity.

Operational Data Store ("ODS") to provide monitoring services for the smart meter network and act as a 'clearing house' for all reports received from the smart meters and the Ontario Meter Data Management and Repository ("MDM/R"). This year, BWP continues to work through various test sets as prescribed by Ontario's Independent Electricity System Operator ("IESO") such that BWP may integrate its systems with the Ontario MDM/R. Testing is mandatory and serves to verify that LDCs are prepared to begin sending meter read data to the MDM/R to allow for Time-of-Use billing. BWP is scheduled to complete testing and start sending meter read data to the MDM/R in February 2012. This timeline, however, is highly dependent on the IESO's ability to meet its current target to release version 7.2 into the MDM/R's production environment.

6.3 Supervisory Control and Data Acquisition

Bluewater Power's Supervisory Control and Data Acquisition ("SCADA") system was first implemented in 1995 as a VMS-based system for telemetry and control of its distribution system. In 2005, however, the system was upgraded to a Windows-based platform for ease-of-use and greater reliability. The dual-redundant system allows for a seamless transition of data to a back-up system without affecting the continuity of system operation, thus providing a high level of system reliability and availability.

The system models all but four of the substations, two of which will be gradually eliminated and the other two will be added to the system. Telemetry of the modeled stations allows for real-time analogue and status data to be monitored, such as breaker and recloser status, bus voltages and feeder currents. Although real power (kW), reactive power (kVAR) and apparent power (kVA) are not telemetered these, and other values (such as daily and monthly peaks), are calculated from telemetered analogue data. BWP however, intends to upgrade several substations to install new relays and upgrade communications to allow for telemetry and greater accuracy of real, reactive and apparent power. Additionally, telemetry of a subset of these substations allows for control of feeder and main breakers, reclosers and/or motor-operated switches. The result of such a configuration is faster identification of faults with faster and remote restoration of supply (reduced outage duration), resulting in an improvement in reliability indices and service quality.

Currently, analogue data is maintained in the SCADA system within historical data files. This data may then be retrieved to create various reports, such as historical feeder loading or daily/monthly peaks.

6.4 Geographic Information System

In 1999, BWP began implementation of its ESRI Geographic Information System. The system allows for mapping the land base of the BWP distribution service territory as well as mapping of BWP-owned assets with respect to the land base. Major assets currently maintained within the GIS include protective devices (switches, fused switches, circuit breakers, reclosers), transformers (pole mount, pad mount, power), conductor (overhead and underground, primary and secondary), substations, poles and underground structures. As new major assets are installed or existing assets replaced, the GIS is updated to reflect the change in in-service equipment. Asset attributes are also maintained within the GIS, serving as a repository for this data and include, but are not limited to, asset identification number, asset size/material, operating voltage, phase, as applicable to the asset.

In addition to identification of service territory and assets an application of the GIS and mobile device is also used for inspection findings documentation during the visual patrol of the overhead and underground distribution system. The GIS is also used for electronic retention of maintenance records, as applicable, that are originally paper-based. The use of the GIS in these capacities is further discussed in Section 7 below. Generally, BWPs use of the GIS in these various roles aids in ensuring accurate data is captured in the GIS.

Such functionality reduces both error and effort, compared to a traditional paper-based system, and allows for greater ease and efficiency in retrieving records or data.

6.5 Outage Management Database

Outage data is compiled in an outage management database, developed by BWP in MS Access, as outages occur. The database, generally utilized by the Operations Project Coordinator and Control Room Operators, facilitates reporting of service interruptions, identified by one of two methods: the SCADA system, providing notification of feeder outage(s) or through notification provided by individual customers. Data includes information such as cause (similar to Table 15.2 of the Distribution Rate Handbook), date and time of interruption, type of fault experienced, effected feeder(s), equipment and interruption device. The total number of customers experiencing the interruption is also documented. The number of customers is determined by referencing a spreadsheet, identifying the total number of customers on each BWP feeder; alternatively, customer count may be determined through the GIS. The response time, identified as time of arrival, is documented and allows for a record of time between identification of the outage and on-site response to address the outage. Following restoration of power, the total time of the outage (restoration time) is documented. From the customer count and outage time, the customer outage minutes may be calculated and utilized for calculation of Service Reliability Indices (“SRI”s).

For each service interruption originating on BWP’s distribution system, or experienced by BWP, a field interruption report (Appendix 15) is produced with data from the system for documentation of information specific to the outage. Information and data, as noted above, is documented in the database to facilitate metrics identification and reporting (refer to Section 7.3 below).

7 Documentation & Data Analyses

7.1 Guidelines for Inspection and Maintenance Programs

Many of BWP’s processes for its inspection and maintenance programs are documented. To ensure consistency in the implementation of the routine visual patrol of the overhead and underground distribution system, and in documentation of inspection data, BWP has developed general guidelines for inspection, attached as Appendix 1. The guidelines provide a definition of both urban and rural service areas and provide direction for components of major assets to be assessed. The guidelines also provide direction for categorizing deficiencies and assigning risk ratings to individual assets.

Documentation and guidelines are subject to continuous review. Consideration is given to enhancing existing documentation and developing new policies, procedures and/or guidelines to facilitate inspections and maintenance and to ensure consistent documentation thereby allowing for more consistent analysis and reporting of data and contribute to the safe and effective operation and management of BWP assets.

7.2 Information and Document Management

7.2.1 Inspection Records

With respect to scheduled inspections, Appendix C, Table C-2 of the DSC provides a sample annual inspection summary report which “provides a summary of the patrols scheduled and carried out during the year as well as target dates for completion of patrols which were not completed as planned”[10]. BWP has adopted a similar

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[10] Ontario Energy Board’s Distribution System Code, Appendix C, ‘Minimum Inspection Requirements’, Section C.1, page 10.

report, implemented within the GIS, for documenting and measuring the progress of scheduled and completed inspections to ensure compliance with the patrol frequency of Appendix C. The report (attached as Appendix 16) identifies the target inspection/completion date, issue date, completion date, status and next inspection date for urban and rural patrols of the overhead and underground distribution system. A similar database has also been developed for substation inspections and interfaces with the GIS such that records within the database are also maintained in the GIS and may be viewed from the GIS.

An original paper-based process, documentation of inspection records from the visual patrol of the overhead and underground distribution system is now facilitated through the use of ESRI's ArcPad, a mobile field mapping and data collection software application that provides the inspector with remote access to GIS data. The application, deployed on a tablet PC, is utilized for map viewing and data collection during inspections. On a routine basis and prior to the visual patrol, maps of sub-areas subject to inspection, including those BWP assets within the area, are assembled by the GIS Administrator and downloaded to the tablet PC by the inspector. The field application provides identical mapping detail as is available in the GIS database, thereby allowing the inspector to view the most recent information related to BWP's distribution system and assets. Various data tables exist within the application to allow for documentation of asset-specific attributes, inspection records and maintenance records. The attributes table serves as confirmation of the attributes as identified in the field, such as nomenclature, pole height, transformer size, etc. The inspection table, also specific to each asset, is a combination of text fields and drop-down menus for documentation of the inspection date, inspection and condition assessment data, and comments. The third table allows for documentation of maintenance history. The tablet may be synchronized to BWP's network such that data from these data tables is uploaded to the enterprise GIS architecture for use by Engineering and Operations. The use of a tablet PC that may be synchronized with the GIS aids in ensuring accurate data is captured in the GIS; also, since it is electronic, the response time to capture this data in the GIS is less than if a traditional paper-based system was used.

The resistograph used for pole testing also allows for results to be both generated and retained electronically. As with electronic records in general, this method of obtaining and storing pole testing records allows for ease in data reusability, reduced errors and greater efficiency in accessing records.

Inspection and condition assessment documentation of distribution stations has been primarily paper-based, including inspection/assessment data documented on an inspection form as well as storage of those forms which are retained in paper format. BWP has now implemented a system whereby monthly substation inspection records are transferred to a database coupled with the GIS.

7.2.2 Maintenance Records

BWP utilizes paper-based reporting for several maintenance or secondary inspection programs. On the overhead distribution system, this includes reports and/or work orders from thermographic infrared inspection, feeder inspection, insulator washing and vegetation management activities, including demand work. On the underground distribution system, paper-based reports and/or work orders are utilized for vault inspection, subdivision maintenance and dry-ice cleaning. For substations, paper-based reports and/or work orders are applicable to thermographic infrared inspection, preventive maintenance and condition-based maintenance activities. However, for condition-based maintenance and those maintenance activities initiated through a work order (feeder inspections and vegetation management for example), information related to maintenance performed (e.g. labour, material, specific remediation) is also archived electronically in the work order system and in the maintenance history of an asset within the GIS. This allows for readily available and accessible maintenance/replacement history for those assets with an identification number.

7.3 Reporting

BWP prepares several reports to facilitate analysis of its operation of the distribution system. These reports are prepared from several data sources, including the outage management database and geographic information system.

As noted in Section 6.4 above, the GIS is used to map BWP assets and incorporate relevant asset information such as attribute data. Additionally, the GIS is used to capture inspection and maintenance data, as applicable. BWP utilizes this data, in particular pole condition data, to query the GIS such that it produces a report of risk ratings, as assigned during inspection. The report illustrates, by colour, regions or pole lines and their respective condition.

Reports from the outage management database include the field interruption report and monthly reports summarizing each of the following:

- Service Reliability Indices
    - System Average Interruption Duration Index (“SAIDI”)
    - System Average Interruption Frequency Index (“SAIFI”)
    - Customer Average Interruption Duration Index (“CAIDI”)
- Number of momentary outages per month
- Emergency callout response times for urban and rural areas within the distribution service area

The reports are issued by the Regulatory Department for submission to the Board. Additionally, the reports are submitted to shareholders and Operations staff for use as described below.

7.3.1 Shareholder Outage Tracker

Data from the outage management system is exported into MS Excel whereby reliability statistics for each of BWP’s shareholders (City of Sarnia, Village of Oil Springs, Town of Petrolia, Village of Point Edward, Watford and Municipality of Alvinston) is reported and trended on a monthly basis in the shareholder outage tracker report (Appendix 17). Service interruptions are classified as momentary (outages under one minute in duration), minor (outages exceeding one minute in duration and affecting less than 15 customers, excluding scheduled outages), and large (outages exceeding one minute in duration and affecting more than 15 customers, again excluding scheduled outages).

7.3.2 Control Room Trending

Data from the outage management database is also utilized by Control Room Operators to trend feeder outages. Both momentary and large outages are documented on an individual feeder basis, with causes identified and the itemization of defective equipment, identifying the type of equipment that failed.

7.3.3 Seasonal Feeder Outages

From the control room trending data, seasonal and feeder service interruptions (Appendix 18) are prepared, highlighting the number of auto reclosures, large outages and causes of large outages over a two-year period. Again, a discussion of data and trends ensues with subsequent implementation of maintenance and capital programs as applicable.

7.3.4 Operations Leading Indicators

This annual report (sample attached as Appendix 19) is presented to the BWP Board of Directors, outlining leading indicators such as pole inspections and replacements, vegetation management and animal protection. The report is prepared from service interruption data, maintained within the outage management database, and from work order data. The primary purpose of this report is to identify goals for these leading indicators and, from extrapolated data, gauge the utility's performance with respect to achieving those goals.

7.4 Data Analyses

Inspection and maintenance data, reports and internal meetings all reflect the status of the distribution system, facilitating data analyses and contributing to BWP's knowledge and understanding of its assets and operation of the distribution system. Data analyses may follow a formal or informal process. In the former, reports as noted above are reviewed and root-cause analyses performed. With informal data analyses, trends are generally observed by and discussed between staff and management as each has training and substantial experience with distribution systems.

Generally, data analysis comprises a review of data, root-cause analysis followed by prioritization and implementation of maintenance or capital strategies over a period of time.

The systematic approach of inspections, condition and age assessment, maintenance and data analysis enable BWP to identify risk to its assets and consider the risk with respect to consequence of failure, capital expenditures for replacement and/or operations expenditures for refurbishment thereby outlining priorities and justification for BWP budget forecasts and spending with the ultimate goal of enhancing the safe and reliable operation of the distribution system.

Examples of such analysis and the resultant effect on capital and maintenance expenditures for the distribution system follow below:

- BWP utilizes the pole condition report to profile the overall condition of a pole line in a particular area, allowing for root-cause analysis (e.g. aging poles) and identification of regions at risk for failure. BWP may then consider these risks with respect to planning, providing prioritization and justification for capital or operations expenditures, or for analysis of maintenance frequencies and practices.

- Large outages, in particular from the Shareholder Outage Tracker report are trended and reviewed by Operations to assist in root-cause analysis and allow for subsequent implementation of appropriate maintenance to mitigate further interruptions. Review of outage management data revealed a significant number of service interruptions caused by lightning. Through formal analysis and discussion with neighbouring LDC's the specific cause was identified as the arrangement of the protection scheme. As such, BWP implemented a program to modify the protection scheme and install additional lightning arresters at specific points on the distribution system.

- BWP's analysis and the trending of thermal anomalies, visible through infrared thermography, revealed repeated and numerous deficiencies with specific insulators. Root-cause analysis of the habitual deficiencies is performed and addressed through capital expenditures for replacement. That is, a limited replacement program is in place to proactively replace insulators of that variety to minimize recurrence of deficiencies, inhibit failures, and provide for continuous improvement to system reliability and operational safety.

- Analysis of subdivision maintenance inspection data reveals corroded transformer lids; experience and analysis of program data allows BWP to realize an emerging trend and results in a concerted effort between Operations and Engineering to establish a new capital lid replacement program, replacing those lids presenting an imminent threat to safety and/or reliability.

- Analysis of relay operation reveals that despite higher precipitation levels in some years, insulator contamination causes relay operation and outages since rain does not necessarily provide a thorough cleaning of all planes of the insulator. BWP therefore concluded annual implementation of the insulator washing program a necessity, reducing service interruptions and improving system reliability.

- Analysis of outage information reveals areas of lower reliability. Subsequent review and root-cause analysis can identify a lack of animal protection. Therefore, a multi-year capital program is in place for installation of animal protection and for the purchase of assets with built-in animal protection to improve reliability.

8 Capital Budget & Five-Year Forecast

Development of the BWP capital budget and five-year forecast occurs simultaneously and begins in the third quarter of each year with identification of projects proposed for inclusion within each. The scope and proposed expenditures of each project is developed and prioritized by representatives from both the Engineering and Operations departments. A draft budget and forecast is then presented to senior management and subsequently to the BWP Board of Directors for review of both and approval of the annual budget in the fourth quarter.

8.1 Identification and Prioritization of Capital Projects

Projects for inclusion within the capital budget and five year forecast follows a bottom-up approach. That is, BWP continuously collects and analyze data from its inspection and maintenance activities, various reports produced outlining the condition, age and performance of the distribution system and through formal and informal planning processes. Subsequently, various projects are identified and prioritized for implementation in the upcoming year (within the annual budget) or in subsequent years (within the five-year rolling forecast). Prioritization of capital projects is as follows:

1. Demand Projects / Regulatory Drivers
2. BWP Initiatives

8.1.1 Demand Projects / Regulatory Drivers

Demand projects and regulatory drivers are those projects driven by external entities, specifically Cities/Municipalities, customers, government and/or regulatory bodies, and are generally non-discretionary. BWP continuously receives requests to relocate a pole line to accommodate municipal road works or may be required to supply a new subdivision or commercial development. BWP also has obligations to meet regulatory objectives.

BWP strives to meet its obligations to customer and municipal demands. BWP is generally apprised of these demands through its participation in monthly utility planning meetings. These meetings, in which various utilities, the municipalities and developers participate, are utilized as a forum to provide notification of various upcoming or forecasted projects and to coordinate utilities for those projects. As such, demand projects are generally always included within the annual capital budget and may also be included within the five-year forecast where indicated through utility planning meetings. The capital expenditures required to fulfill demand projects are estimated and based on material quotes and/or experience and may be extrapolated from previous years' budget; alternatively and for estimating expenditures for the five-year forecast, BWP utilizes projections of the expenditures, accounting for such things as inflation. Numerous residential projects and/or new connections are proposed and BWP is able to reasonably foresee an average construction of four to five subdivisions with approximately 20 to 30 lots per subdivision per year, the corresponding expenditures are accounted for accordingly within the proposed capital budget.

8.1.2 BWP Initiatives

BWP continuously collects and analyzes data from its inspection and maintenance activities, as well as from the various reports produced outlining the condition, age and performance of the distribution system. Subsequently, various initiatives are identified as required to maintain or enhance the safety and/or reliability of the distribution system. At least 80% of these initiatives are recurring and may comprise activities that are required year after year, for example pole replacements, or may comprise a single project that requires execution over multiple years, for example voltage conversion to eliminate a substation. Because of the recurring nature of these initiatives, the annual budget and five-year forecast include such initiatives.

Recurring initiatives may be categorized as one of the following:

1. Asset Replacement
2. System/Safety Enhancements
3. Capital Expansion

Asset replacement initiatives include replacement of existing distribution equipment (e.g. transformers, poles), tools, fleet, buildings (or building components) due to end-of-life; this category also includes capital rebuild projects. Generally, these initiatives are identified through inspection and maintenance programs and are required for ensuring safety and/or reliability of service. Assets are evaluated on the basis of age and condition; also performed is an evaluation to assess whether refurbishment (to extend the life cycle) or complete replacement is the most prudent option. Initiatives within this category include wood pole replacement, cap and pin-style cross-arm replacement and porcelain insulator replacement.

System/safety enhancement initiatives include neutral upgrades, voltage conversion, safety signage, substation upgrades and load balancing projects. Generally, these initiatives are identified through inspection and maintenance programs, load growth forecasts and/or report analysis (refer to Section 7.3 above) and are required for ensuring/enhancing safety/reliability of service, to accommodate forecasted increase in load and/or to optimize configuration of the distribution system. Initiatives within this category include installation of animal protection or lightning arresters to improve reliability, installation of a second substation transformer for redundancy in the event of a failure of the primary transformer and balancing of feeder loadings to avoid overloading during peak periods.

Capital expansion initiatives include proposed assets for new connections and system expansion specifically to accommodate load growth. Generally, these initiatives are identified through forecasts or system planning and are required to accommodate forecasted increase in load and/or to ensure availability of supply. These may include feeder extensions to accommodate load growth and ensure supply reliability for customers.

For each the recurring initiatives identified within the annual budget and five-year forecast estimates of the amount of capital contribution required are compiled. The estimates are generally based on actual expenditures from previous years where the scope of work is similar; alternatively, where the scope of work varies, expenditures are proportionately estimated. For the forecast, estimates of initiatives are adjusted annually based on achievements for a recurring project in previous years with respect to objectives in the upcoming years.

Approximately 80% of BWP initiatives are recurring while the remaining 20% are generally one-time expenditures. As with recurring initiatives, these single initiatives are identified through inspection/maintenance programs, report analysis or forecasts and are warranted to achieve similar objectives, namely ensuring or enhance safety and reliability. A typical single initiative is BWP's upgrade of its manhole structures to coincide with the City of Sarnia's extensive road works.

8.2 Capital Budget and Forecast Review and Approval

Estimates of capital expenditures are proposed, as noted above, and documented together with an overview of the scope of work for each of the BWP initiatives and demand and regulatory projects. The estimates are compiled and presented in the draft budget, within the fourth quarter, to a senior management team comprised of senior management from each department and BWP's President/Chief Executive Officer ("CEO"). At this time, the five-year forecast is also presented. During the review process, each department presents its capital budget and forecast to the President/CEO. A discussion of scope of work and justification with respect to proposed expenditures may also ensue. The President/CEO subsequently reviews the proposed projects, ensuring each is justified and prudent in both scope and cost. There may be multiple iterations of the review process, whereby projects may be reprioritized, until the draft budget is approved by the senior management team.

Following senior management approval, a final draft of the annual capital budget and five-year forecast is presented by the President/CEO to the BWP Board of Directors. While both are reviewed by the Board of Directors, only the annual capital budget is formally approved, also within the fourth quarter.

8.3 Variances from the Approved Capital Budget

Within the budget year the work order system is utilized to track labour and material expenditures for any given project or work performed. Expenditures are subsequently translated into a corresponding Uniform System of Accounts ("USoA") code for regulatory financial reporting. At the end of each month the Finance Department issues departmental reports that are used to evaluate the financial status of a project, presenting both the budgeted amount and actual expenditures.

While BWP strives to develop an accurate annual budget, unforeseen changes to projects may occur and could result in a variance from Board of Directors-approved funds. Such changes may be due to, customer requests or municipally mandated programs. Additionally, projects may be added to the current program or projects included within the budget may be deferred to subsequent years. Where variances are anticipated but do not result in an increase to approved funds (i.e. overspending of the budget, as a whole, is not anticipated), the variance is presented as a business case and includes the additional funds required and justification. Prior to accommodating any such variance, approval must be granted by BWP's President/CEO. However, if variances result in overspending of the budget, then approval from the BWP Board of Director's must be first obtained.

9 Operations, Maintenance & Administrative Budget

Generally, any maintenance recommendations resulting from the routine visual patrols are addressed within this maintenance budget, and also include preventive, predictive and condition-based maintenance activities.

9.1 Overview

The Operations, Maintenance & Administrative (“OM&A”) budget, developed by the Operations department, identifies administrative expenditures as well as routine and non-routine operations and maintenance expenditures for the budget year within two major operations cost center categories: Lines and Controls, developed by the Line Supervisor and the Manager Technical Resources for BWP Distribution Corporation, respectively.

9.2 Budget Details

Expenditures within each of these two cost centers are further categorized as one of the following line items included within the OM&A budget (which may or may not be included within a given year’s budget):

Operations – Lines Department

1. Advertising
2. Boot/Clothing Allowance
3. Cell Phone/Smart Phone
4. CNR Lease
5. Collection Charge
6. Communications – Voice
7. Consulting
8. Contract Employees
9. Contracted Services
10. Contracted Services – BWP
11. Donations
12. Education Assistance
13. Equipment Testing
14. Fire Retardant and Safety Clothes
15. Fitness Expense
16. Hardware
17. Insulator Washing
18. Joint Pole Use
19. Labour
20. Licences
21. Locates
22. Manholes & Vaults
23. Meals
24. Memberships
25. Miscellaneous Supplies
26. Non-Stock
27. Oil Disposing & Testing
28. Overtime
29. Records Management
30. Rentals
31. Safety Supplies
32. Salary
33. Secured Delivery
34. Stores – Maintenance O/H Conductors
35. Stores – Maintenance Poles, etc.
36. Stores – Maintenance U/G Conductors
37. Students
38. Thermovision
39. Tools
40. Training
41. Transformer Maintenance
42. Travel
43. Tree Trimming
44. Vacuum Excavation

Operations – Controls Department

1. Answering Service
2. Boot/Clothing Allowance
3. Cell Phone/Smart Phone
4. Communications

12. Labour
13. Meals
14. Memberships
15. Overtime
16. Salary

5. Communications Voice
6. Consulting
7. Contracted Services
8. Education Assistance
9. Fire Retardant and Safety Clothes
10. Fitness Expense
11. Internet
17. SCADA
18. Secured Delivery
19. Stationary Supplies
20. Stores – Maintenance O/H Conductors
21. Tools
22. Training
12. Travel

9.3 Budget Development Process

In October or November of each year, development of the annual OM&A budget commences and comprises a review of past and projected operations, maintenance and administrative expenditures whereby items for consideration are presented and reviewed with respect to routine and non-routine or unforeseen expenditures. Routine inspection and maintenance expenditures are estimated based on historical values, whereas non-routine expenditures may be estimated through quotations. For the majority of activities, inspection and maintenance activities are routine and, as such, expenditures are estimated from previous years and adjusted to reflect changes to scope of work as identified through communications within Operations or between Engineering and Operations, or through data analysis of inspection and maintenance data. In addition to operations and maintenance data (including fleet and property maintenance expenditures), the budget also reflects administrative items, for example communication devices, clothing essential to job performance and forecasted staff training and development.

9.4 Approval of O&M Budget and Management of Budget Variances

The budget development process typically occurs in October or November. Following development of a draft Operations OM&A budget, the draft is presented to the VP of Operations for review of expenditures and supporting documentation (where applicable) and then evaluated for cost, scope of work and justification. The budget is then presented to the senior management team and BWP Board of Directors in the process noted in Section 8.2 above. Additionally, variances in the Operations OM&A budget are managed as described in Section 8.3 above.

APPENDIX 1

ArcPad Documentation

General Notes:

Area

Urban means those areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people. Maintenance cycle is 3 years.

Rural means those areas that are less populous suburban areas and are outside of a standard metropolitan area. Generally, rural will be defined on a circuit or sub-circuit basis, as areas with a line density of less than 60 customers per kilometre of line. It is recognized that there may be circumstances where an area may be treated as urban even though by this definition it may be defined as 'rural'. Maintenance cycle is 6 years.

Risk Rating – Any item flagged red or orange must have a comment

Red – immediate and urgent attention is required. Poses a risk to the general public, utility workers, property and/or the environment. E.g. Broken, rotten, covers missing, leaking, etc.

Orange – requires timely, corrective action to mitigate hazard to the public, employees, property or environment. E.g. Damaged, life cycle replacement.

Yellow – maintenance will be required in 2 – 5 years – life cycle replacement.

Blue – maintenance will be required in 5 – 10 years – life cycle replacement.

Green – maintenance will be required in 11 – 20 years – life cycle replacement.

Y/N – N means that no maintenance is required; **Y** means that maintenance is required and a comment should be entered. If an item is flagged as **Y** for maintenance then it should be questioned if that maintenance can wait for 2 or more years. If the answer to that question is "no" then that item should be coded as 'Red' or 'orange' to indicate that maintenance must be done fairly quickly. Any items coded 'Yellow', 'Blue', or 'Green' are generally those items which will need maintenance 2 years or more away. An example of that may be 'rust'. Any fields changed to "Y" should be coded Red or Orange

Comments

The tablet supports handwriting to text – a brief description of the problem should be entered.

APPENDIX 2

Poles

DateEntered		To be selected
EnteredBy		Will default
Area		Rural or Urban (default?)
RiskRating		Red, Orange, Yellow, Blue, Green
Broken/Rotten	Y/N	Will default to N
Crossarms	Y/N	Will default to N
LooseHardware	Y/N	Will default to N
Pins	Y/N	Will default to N
Insulators	Y/N	Will default to N
GradeChanges	Y/N	Will default to N
GuyGuard	Y/N	Will default to N
GuyTension	Y/N	Will default to N
Terminators	Y/N	Will default to N
Grounding	Y/N	Will default to N
Cutouts	Y/N	Will default to N
CableGuards	Y/N	Will default to N
TransitionBox	Y/N	Will default to N
Conductors		Drop down selection for conductor condition
Vegetation	Y/N	Will default to N
Comments		To be selected from list
DeviceID		Linked field
Work_Completed		Date Field
Work_Order		15 digit text field
Work_Description		50 digit comment field

Transformers

DateEntered		To be selected
EnteredBy		Will default
Area		Rural or Urban (default?)
RiskRating		Red, Orange, Yellow, Blue, Green
OilLeaks	Y/N	Will default to N
Rust	Y/N	Will default to N
Brackets	Y/N	Will default to N
Arrestors	Y/N	Will default to N
Bushings	Y/N	Will default to N
Connectors	Y/N	Will default to N
Elbows	Y/N	Will default to N
Lock	Y/N	Will default to N
Nomenclature	Y/N	Will default to N
Insulators	Y/N	Will default to N
GradeChanges	Y/N	Will default to N
Vegetation	Y/N	Will default to N
AnimalProtection	Y/N	Will default to N
Comments		To be selected from list
DeviceID		Linked field
Work_Completed		Date Field
Work_Order		15 digit text field
Work_Description		50 digit comment field

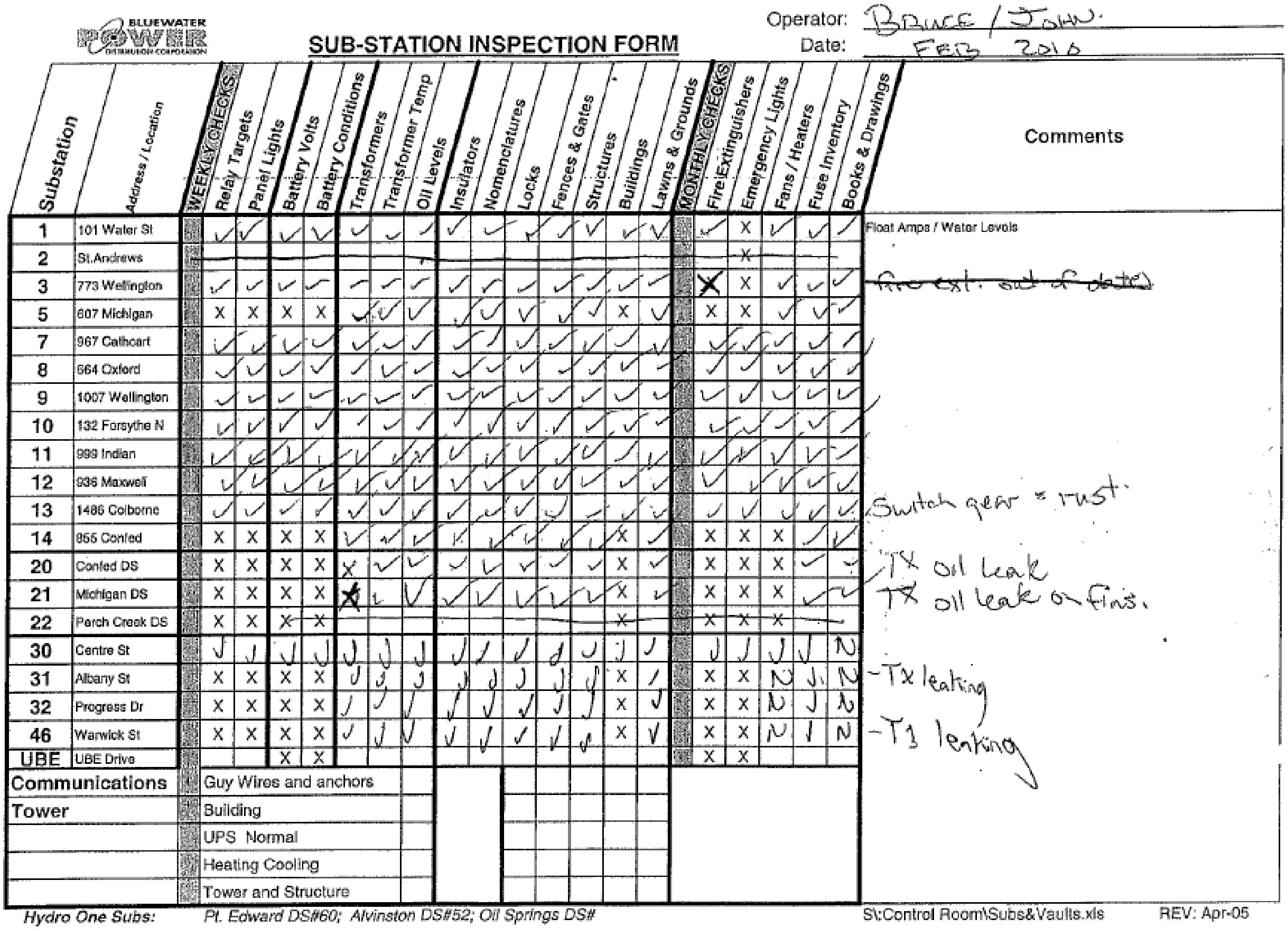
Protective Devices

DateEntered		To be selected
EnteredBy		Will default
Area		Rural or Urban (default ?)
RiskRating		Red, Orange, Yellow, Blue, Green
LightningArrestor	Y/N	Will default to N
Connection	Y/N	Will default to N
Grounding	Y/N	Will default to N
Bent/Broken	Y/N	Will default to N
Locks	Y/N	Will default to N
Nomenclature	Y/N	Will default to N
Vegetation	Y/N	Will default to N
Comments		To be selected from list
DeviceID		Linked field
Work_Completed		Date field
Work_Order		15 digit text field
Work_Description		50 digit comment field

Fused Switch

DateEntered		To be selected
EnteredBy		Will default
Area		Rural or Urban (default ?)
RiskRating		Red, Orange, Yellow, Blue, Green
LightningArrestor	Y/N	Will default to N
Connection	Y/N	Will default to N
Grounding	Y/N	Will default to N
Bent/Broken	Y/N	Will default to N
Locks	Y/N	Will default to N
Nomenclature	Y/N	Will default to N
Vegetation	Y/N	Will default to N
Comments		To be selected from list
DeviceID		Linked field
Work_Completed		Date field
Work_Order		15 digit text field
Work_Description		50 digit comment field

APPENDIX 3



BLUEWATER POWER DISTRIBUTION CORPORATION

SUB-STATION INSPECTION FORM

Operator: Bruce / John.
Date: Feb 2010

Substation	Address / Location	WEEKLY CHECKS	Relay Targets	Panel Lights	Battery Volts	Battery Conditions	Transformers	Transformer Temp	Oil Levels	Insulators	Nomenclatures	Locks	Fences & Gates	Structures	Buildings	Lawns & Grounds	MONTHLY CHECKS	Fire Extinguishers	Emergency Lights	Fans / Heaters	Fuse Inventory	Books & Drawings	Comments
1	101 Water St		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	X	✓	✓	✓	Float Amps / Water Levels
2	St.Andrews																		X				
3	773 Wellington		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		X	X	✓	✓	✓	~~Fire ext. out of date~~
5	607 Michigan		X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	✓	✓	✓	
7	967 Cathcart		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
8	664 Oxford		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
9	1007 Wellington		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
10	132 Forsythe N		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
11	999 Indian		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
12	936 Maxwell		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
13	1486 Colborne		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	Switch gear = rust.
14	855 Confed		X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	X	✓	✓	
20	Confed DS		X	X	X	X	X	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	X	✓	✓	TX oil leak
21	Michigan DS		X	X	X	X	X	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	X	✓	✓	TX oil leak on fins.
22	Perch Creek DS		X	X	X	X									X			X	X	X			
30	Centre St		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	N	
31	Albany St		X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	N	✓	N	-Tx leaking
32	Progress Dr		X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	N	✓	N	
46	Warwick St		X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	X	✓		X	X	N	✓	N	-T1 leaking
UBE	UBE Drive				X	X												X	X				

Communications Tower		Guy Wires and anchors
		Building
		UPS Normal
		Heating Cooling
		Tower and Structure

Hydro One Subs: *Pt. Edward DS#60; Alvinston DS#52; Oil Springs DS#*

S:\Control Room\Subs&Vaults.xls REV: Apr-05

APPENDIX 4

Bluewater Power Distribution Corporation

855 Confederation Street,
Sarnia, Ontario.
N7T 7L6

Locations:

Sarnia, Point Edward,
Alvinston, Oil Springs, Petrolia & Watford.

Electrical Infrared Thermographic Inspection

IR Reference # **091077**
Inspection Date: **September 15 - 17, 28 - 30,**
October 1 - 2, 2009.

Item #1

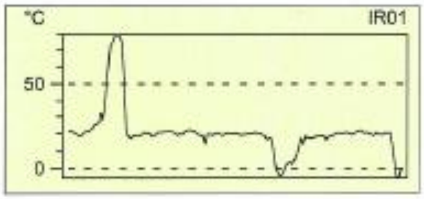
Location

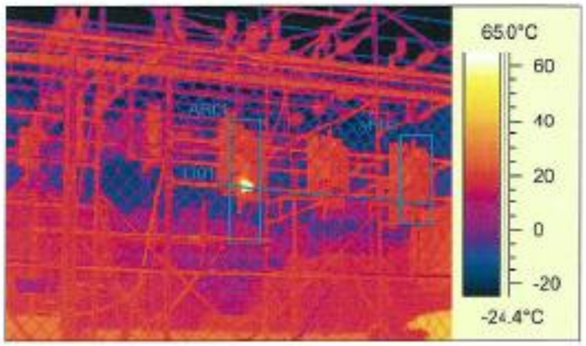
SUBSTATION AT WARWICK
AT GOLD STREET
WATFORD.

Description

LOWER, PIVOT POINT ASSEMBLY ON
RED PHASE BARREL SWITCH FOR
2946 F1-X FEEDER.

Object parameter	**Value**
Emissivity	0.95
Object distance	15.0 m
Ambient temperature	20.0°C



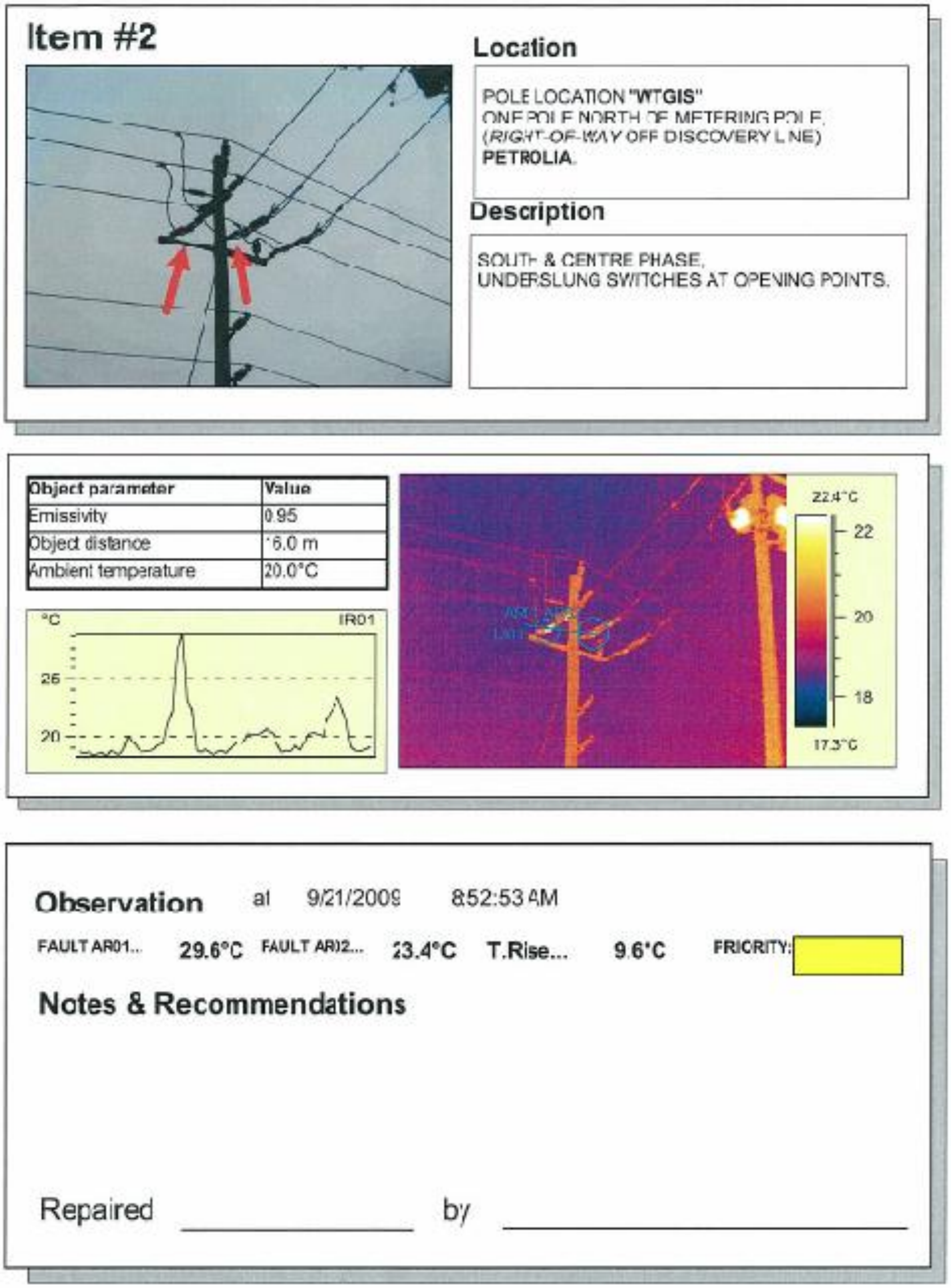


Observation at 9/15/2009 9:50:38 AM

FAULT AR01... **85.2°C** OK AR02... **25.7°C** **T.Rise... 65.2°C** PRIORITY: 🟥

Notes & Recommendations

Repaired ____________________ by ______________________________



Item #2

Location

POLE LOCATION **"WTGIS"**
ONE POLE NORTH OF METERING POLE,
(*RIGHT-OF-WAY* OFF DISCOVERY LINE)
PETROLIA.

Description

SOUTH & CENTRE PHASE,
UNDERSLUNG SWITCHES AT OPENING POINTS.

Object parameter	Value
Emissivity	0.95
Object distance	16.0 m
Ambient temperature	20.0°C

Observation at 9/21/2009 8:52:53 AM

FAULT AR01... 29.6°C FAULT AR02... 23.4°C T.Rise... 9.6°C PRIORITY:

Notes & Recommendations

Repaired ________________ by ______________________________

Item #3

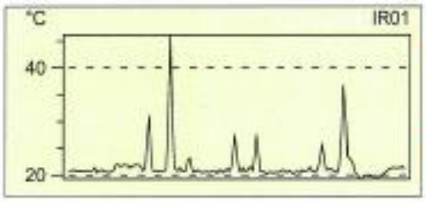
Location

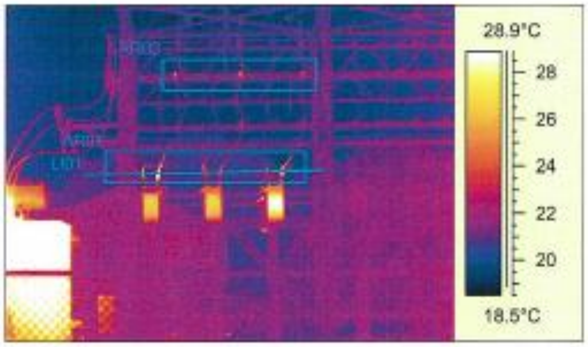
ALBANY STREET
SUBSTATION,
PETROLIA.

Description

UPPER, POTHEAD TERMINATIONS ON RIGHT & LEFT PHASE RECLOSURES AND UPPER STRUCTURE LEAD SUPPORTS FOR **1853 F1** FEEDER.

Object parameter	Value
Emissivity	0.95
Object distance	13.0 m
Ambient temperature	20.0°C





Observation

at 9/21/2009 9:16:26 AM

FAULT AR01... **46.2°C** **FAULT AR02...** **26.1°C** **T.Rise...** **26.2°C** **PRIORITY:** 🟨

Notes & Recommendations

Repeated ________________ by ____________________________

Item #4

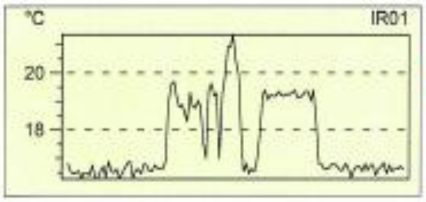
Location

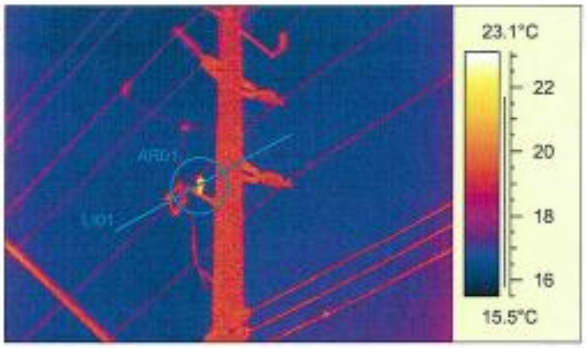
POLE LOCATION **#4059 JX**,
AT #4101 GLENVIEW ROAD,
PETROLIA.

Description

LIGHTNING ARRESTOR,
OFF PRIMARY LINE ON CROSS-ARM.

Object parameter	Value
Emissivity	0.95
Object distance	10.0 m
Ambient temperature	20.0°C





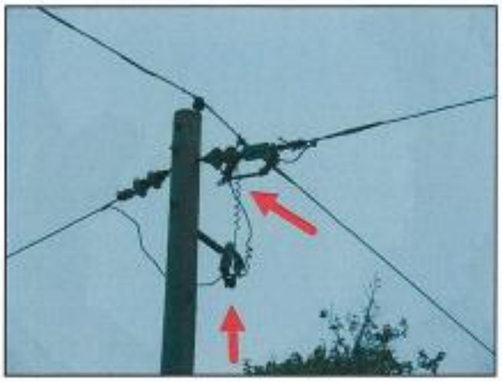
Observation at 9/21/2009 9:29:12 AM

FAULT AR01... **22.4°C** **OK AR02...** **-** **T.Rise...** **2.4°C** **PRIORITY:**

Notes & Recommendations

Repaired ____________________ by ______________________________

Item #5



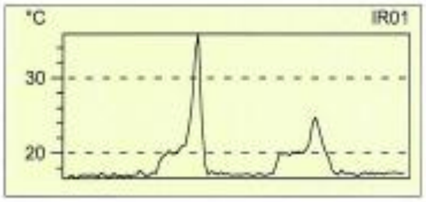
Location

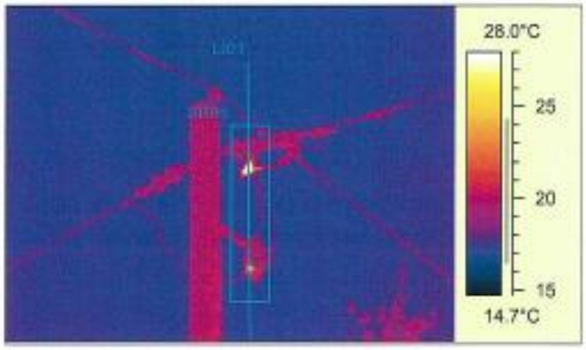
POLE LOCATION **#4120 DF**,
EGAN AVENUE NEAR FLORENCE AVENUE,
PETROLIA.

Description

CLAMP ASSEMBLIES ON
BOTH BOTH PRIMARY SWITCHES.

Object parameter	Value
Emissivity	0.95
Object distance	12.0 m
Ambient temperature	20.0°C





Observation at 9/21/2009 9:38:36 AM

FAULT AR01... **35.9°C** **OK AR02...** - **T.Rise...** **15.9°C** **PRIORITY:** 🟨

Notes & Recommendations

Repeaired ________________ by ____________________________

Item #6

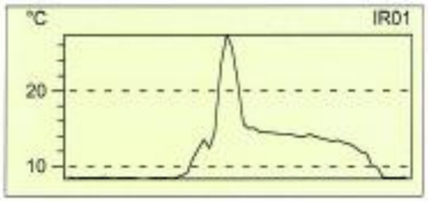
Location

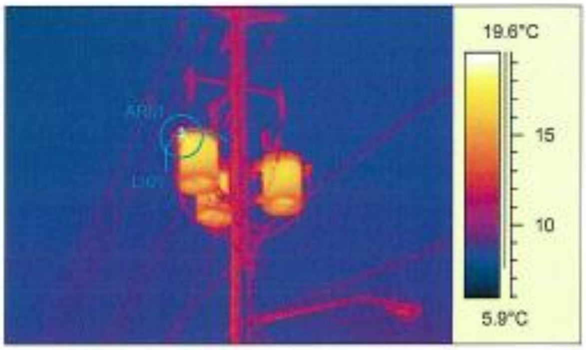
TRANSFORMER LOCATION **#18972**,
CORNER OF LONDON LINE AT BARCLAY DRIVE,
SARNIA.

Description

SECONDARY BUSHING ON FIELD
PHASE TRANSFORMER, LIVE BUSHING.

Object parameter	Value
Emissivity	0.96
Object distance	8.0 m
Ambient temperature	12.0°C





Observation at 9/29/2009 11:39:11 AM

FAULT AR01... **29.2°C** OK AR02... - **T.Rise...** **17.2°C** PRIORITY: 🟨

Notes & Recommendations Loose Secondary.

Repaired ✓ by ______

Item #7

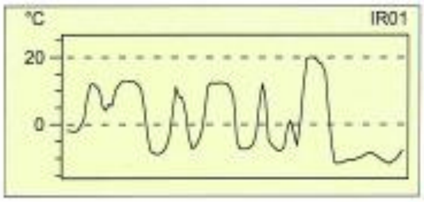
Location

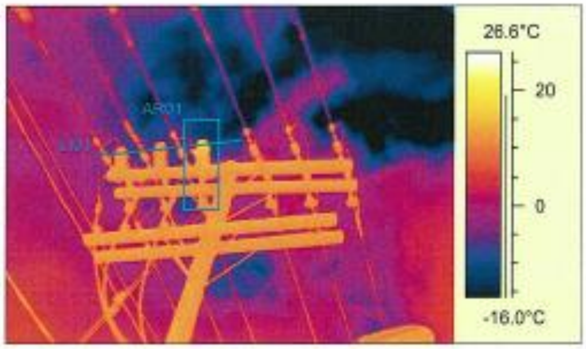
TAG LOCATION **#04211**, (OLD #24A15),
MAXWELL STREET NORTH OF FRONT STREET,
SARNIA.

Description

ROAD PHASE, ENCLOSED SWITCH
ON CROSS-ARM.

Object parameter	Value
Emissivity	0.96
Object distance	9.0 m
Ambient temperature	12.0°C





Observation at 9/29/2009 12:00:45 PM

FAULT AR01... **23.5°C** **OK AR02...** **-** **T.Rise...** **11.5°C** **PRIORITY:** 🟨

Notes & Recommendations

Replaced dead-
blade.

Repaired ✓ by ______

Item #8

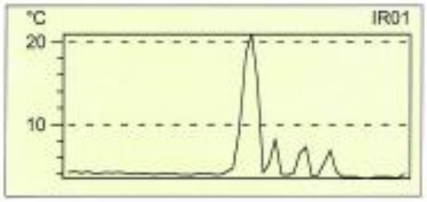
Location

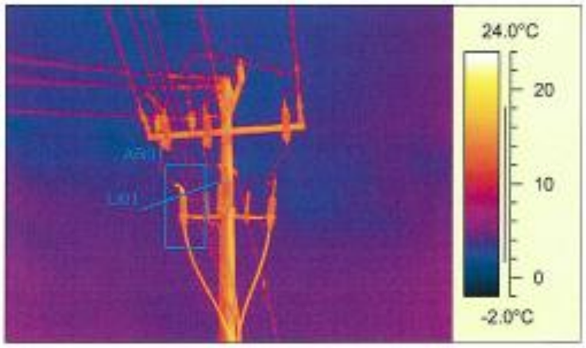
POLE LOCATION **#119S**,
FRONT STREET NORTH,
SARNIA.

Description

UPPER CONNECTION OF
ROAD (BLUE) PHASE POTHEAD
ON RISER/DIP POLE

Object parameter	Value
Emissivity	0.96
Object distance	12.0 m
Ambient temperature	12.0°C





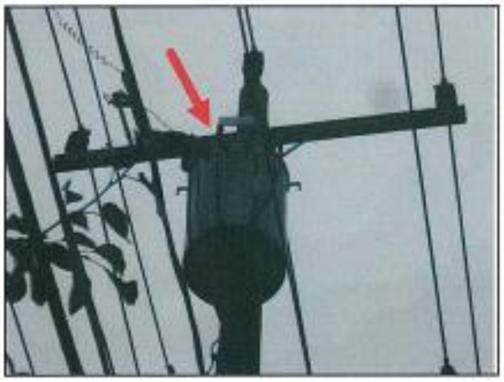
Observation at 9/29/2009 12:19:27 PM

FAULT AR01... **21.2°C** **OK AR02...** - **T.Rise...** **9.2°C** **PRIORITY:** 🟨

Notes & Recommendations loose Connection

Repaired ✓ by ______________

Item #9



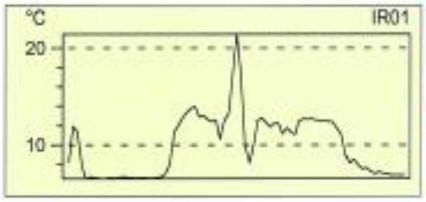
Location

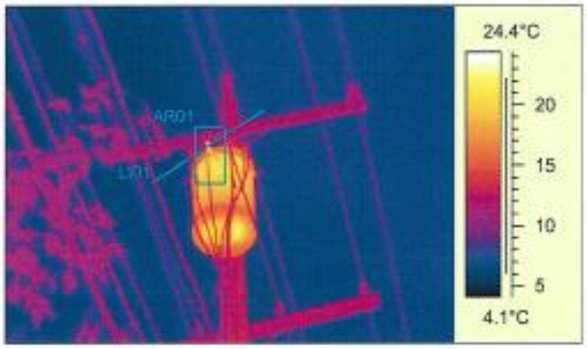
TAG LOCATION **#04351**,
TRANSFORMER LOCATION #**B2542**,
NEAR #1185 MURPHY ROAD,
SARNIA.

Description

SECONDARY TRANSFORMER
BUSHING ASSEMBLY ON TANK.

Object parameter	Value
Emissivity	0.96
Object distance	9.0 m
Ambient temperature	13.0°C





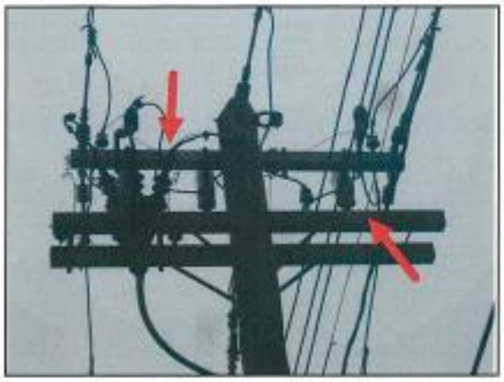
Observation at 9/29/2009 2:30:10 PM

FAULT AR01... **21.8°C** **OK AR02...** **-** **T.Rise...** **8.8°C** **PRIORITY:** 🟨

Notes & Recommendations Secondary bushing.

Repaired ✓ by ____________

Item #10



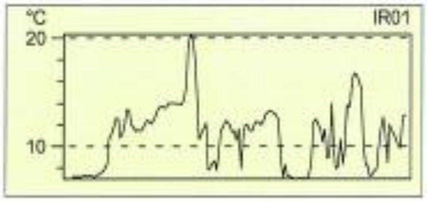
Location

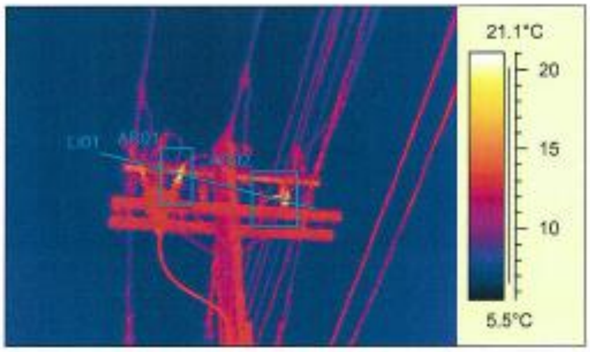
TAG LOCATION **#02182**, (OLD #696),
POLE LOCATION **#477D**,
CHRISTINA STREET AT JOHNSTON STREET,
SARNIA.

Description

FIELD PHASE. UPPER POTHEAD TERMINATION AND FIELD PHASE SWITCH ON CROSS-ARM.

Object parameter	Value
Emissivity	0.96
Object distance	10.0 m
Ambient temperature	13.0°C





Observation

at 9/29/2009 2:52:30 PM

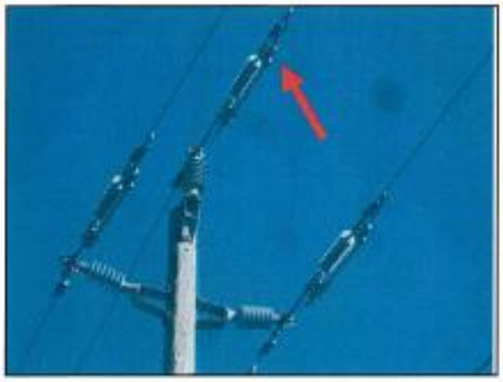
FAULT AR01... **21.5°C** FAULT AR02... **22.5°C** **T.Rise... 8.5°C** PRIORITY: 🟨

Notes & Recommendations

Cleaned + Tightened,

Repaired ✓ by ______________________

Item #11



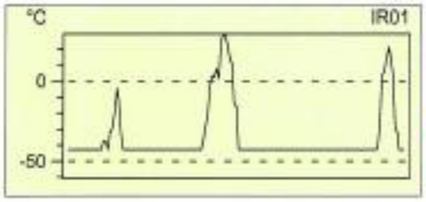
Location

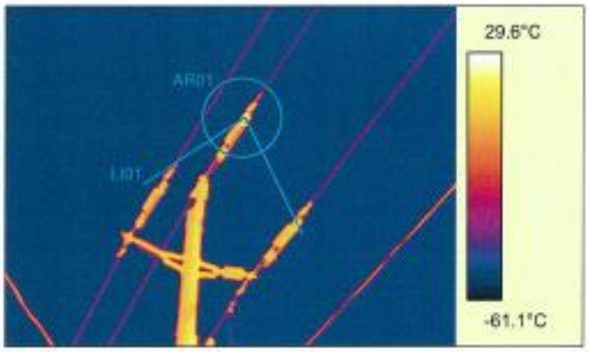
TAG LOCATION #**10396**, (#560),
SWITCH LOCATION #**C3516**,
ROPER STREET, (OPPOSITE *T.E.S.*BUILDING),
SARNIA.

Description

CENTRE PHASE, SWITCH ASSEMBLY
ON PRIMARY LINE.

Object parameter	Value
Emissivity	0.96
Object distance	12.0 m
Ambient temperature	9.0°C





Observation

at 9/30/2009 10:46:28 AM

FAULT AR01... 33.3°C OK AR02... - T.Rise... 24.3°C PRIORITY: 🟨

Notes & Recommendations

Complete

Repaired ✓ by Thomas & Wilson

Item #12

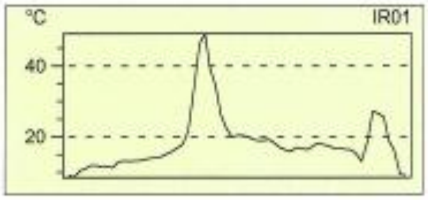
Location

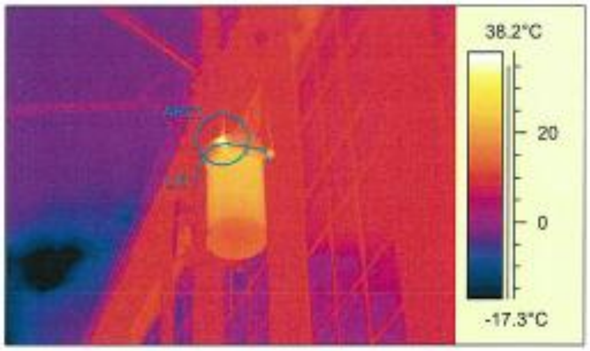
TAG LOCATION **#12815**,
TRANSFORMER LOCATION **#C2487**,
NEAR #546 CHRISTINA STREET,
SARNIA.

Description

SECONDARY BUSHING ON
SINGLE PHASE TRANSFORMER.

Object parameter	Value
Emissivity	0.96
Object distance	8.0 m
Ambient temperature	10.0°C





Observation at 9/30/2009 12:15:03 PM

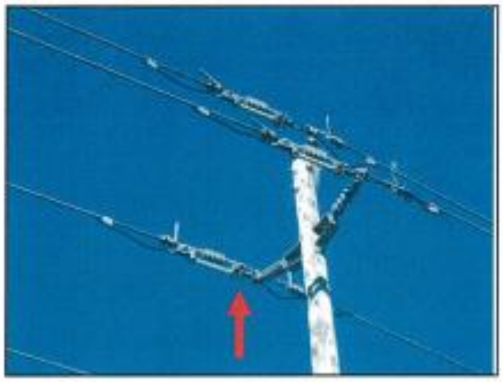
FAULT AR01... **49.0°C** OK AR02... - **T.Rise... 39.0°C** PRIORITY: 🟥

Notes & Recommendations

Repaired.

Repaired ✓ by ____________________

Item #13



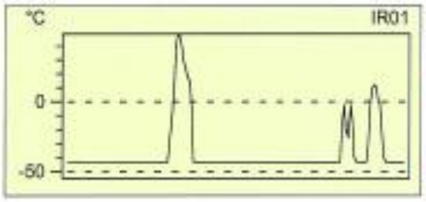
Location

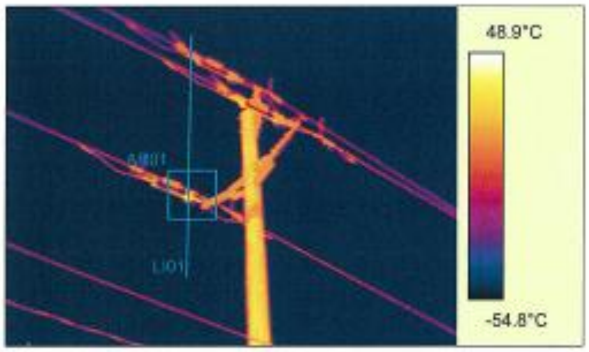
POLE LOCATION #**11543**,
SWITCH LOCATION #**3425**,
SCOTT ROAD NEAR *IMPERIAL OIL - GATE #432*,
SARNIA.

Description

CLAMP ASSEMBLIES ON ALL PHASES
(IN-LINE SWITCHES).

Object parameter	Value
Emissivity	0.96
Object distance	12.0 m
Ambient temperature	12.0°C





Observation at 10/1/2009 10:56:25 AM

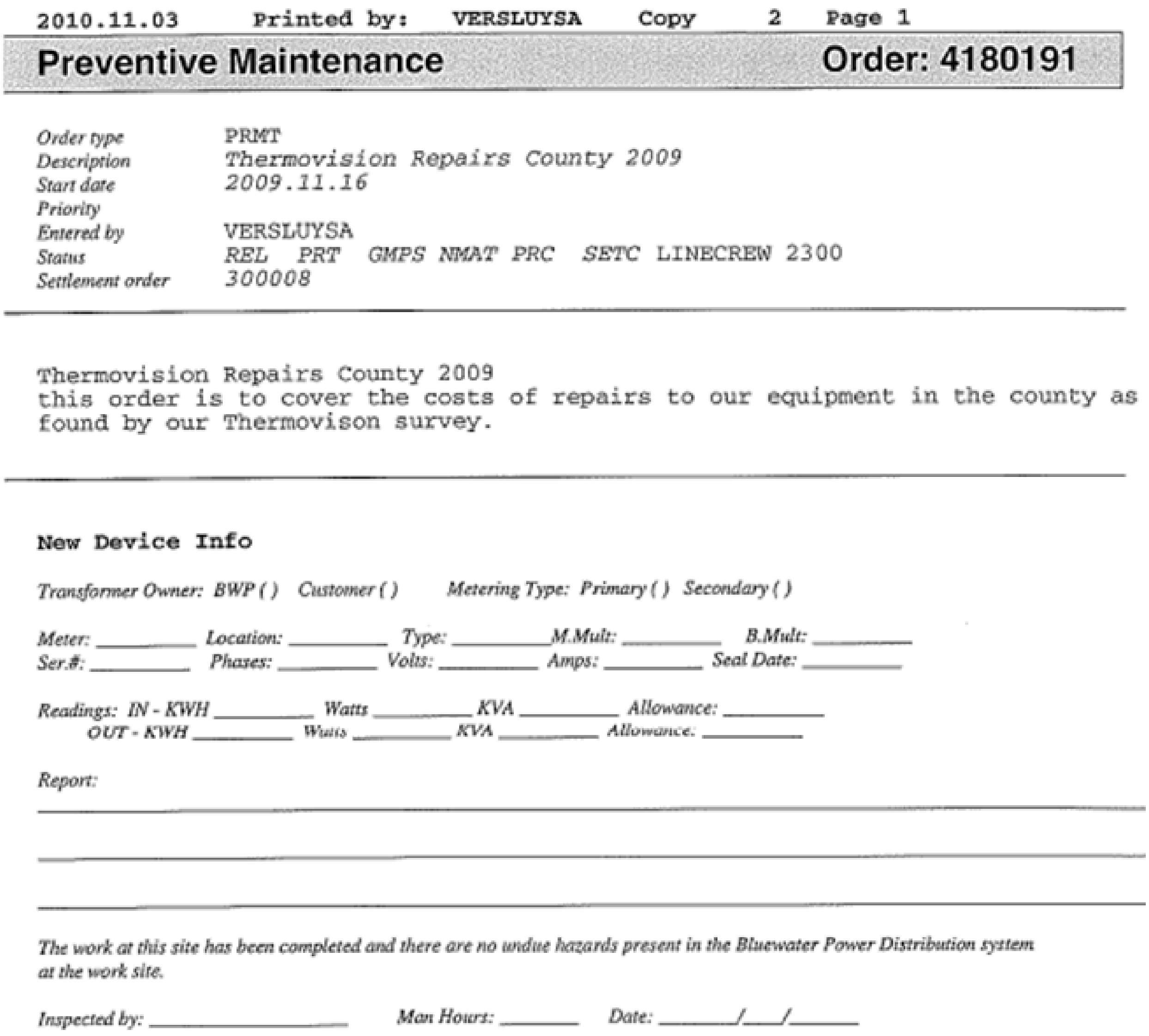
FAULT AR01...	48.7°C	OK AR02...	-	T.Rise...	36.7°C	PRIORITY:	🟥

Notes & Recommendations

Done.

Repaired ✓ by ______

APPENDIX 5



2010.11.03 Printed by: VERSLUYSA Copy 2 Page 1

Preventive Maintenance Order: 4180191

Order type	PRMT
Description	Thermovision Repairs County 2009
Start date	2009.11.16
Priority	
Entered by	VERSLUYSA
Status	REL PRT GMPS NMAT PRC SETC LINECREW 2300
Settlement order	300008

Thermovision Repairs County 2009
this order is to cover the costs of repairs to our equipment in the county as found by our Thermovison survey.

New Device Info

Transformer Owner: BWP ( ) Customer ( ) Metering Type: Primary ( ) Secondary ( )

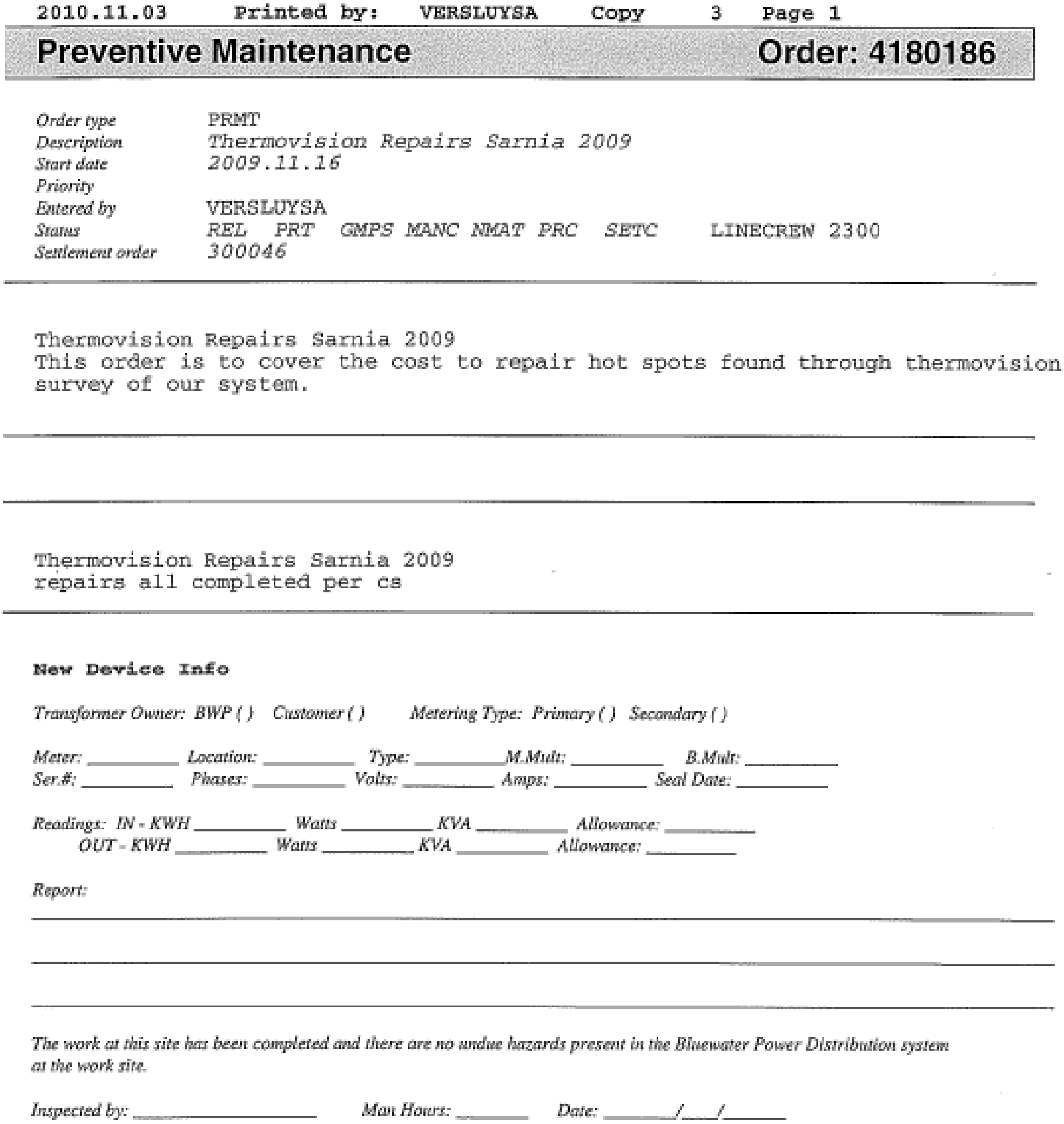
Meter: _________ Location: _________ Type: _________M.Mult: _________ B.Mult: _________
Ser.#: _________ Phases: _________ Volts: _________ Amps: _________ Seal Date: _________

Readings: IN - KWH _________ Watts _________ KVA _________ Allowance: _________
OUT - KWH _________ Watts _________ KVA _________ Allowance: _________

Report:

The work at this site has been completed and there are no undue hazards present in the Bluewater Power Distribution system at the work site.

Inspected by: _________________ Man Hours: _______ Date: _______/___/______



2010.11.03 Printed by: VERSLUYSA Copy 3 Page 1

Preventive Maintenance **Order: 4180186**

Order type	PRMT
Description	Thermovision Repairs Sarnia 2009
Start date	2009.11.16
Priority	
Entered by	VERSLUYSA
Status	REL PRT GMPS MANC NMAT PRC SETC LINECREW 2300
Settlement order	300046

Thermovision Repairs Sarnia 2009
This order is to cover the cost to repair hot spots found through thermovision survey of our system.

Thermovision Repairs Sarnia 2009
repairs all completed per cs

New Device Info

Transformer Owner: BWP ( ) Customer ( ) Metering Type: Primary ( ) Secondary ( )

Meter: __________ Location: __________ Type: __________ M.Mult: __________ B.Mult: __________
Ser.#: __________ Phases: __________ Volts: __________ Amps: __________ Seal Date: __________

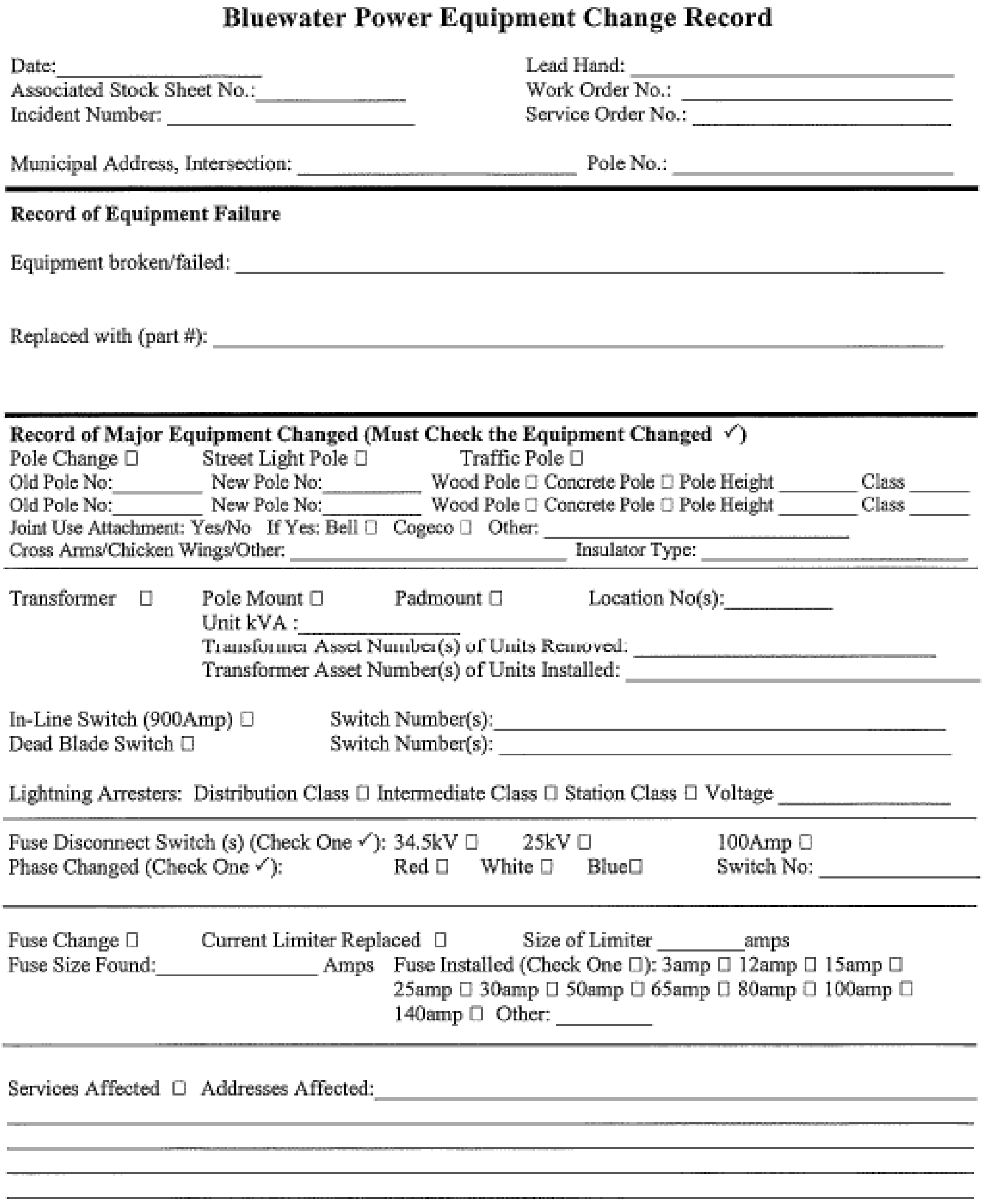
Readings: IN - KWH __________ Watts __________ KVA __________ Allowance: __________
OUT - KWH __________ Watts __________ KVA __________ Allowance: __________

Report:

The work at this site has been completed and there are no undue hazards present in the Bluewater Power Distribution system at the work site.

Inspected by: ____________________ Man Hours: ________ Date: ________/____/_______

APPENDIX 6



Bluewater Power Equipment Change Record

Date:___________________ Lead Hand: ____________________________
Associated Stock Sheet No.:_____________ Work Order No.: ________________________
Incident Number: ______________________ Service Order No.: ______________________

Municipal Address, Intersection: _________________________ Pole No.: _________________________

Record of Equipment Failure

Equipment broken/failed: ____

Replaced with (part #): ____

Record of Major Equipment Changed (Must Check the Equipment Changed ✓)

Pole Change ☐ Street Light Pole ☐ Traffic Pole ☐
Old Pole No:_________ New Pole No:_________ Wood Pole ☐ Concrete Pole ☐ Pole Height ________ Class ______
Old Pole No:_________ New Pole No:_________ Wood Pole ☐ Concrete Pole ☐ Pole Height ________ Class ______
Joint Use Attachment: Yes/No If Yes: Bell ☐ Cogeco ☐ Other: ___________________________
Cross Arms/Chicken Wings/Other: _________________________ Insulator Type: ________________________

Transformer ☐ Pole Mount ☐ Padmount ☐ Location No(s):__________
Unit kVA :______________
Transformer Asset Number(s) of Units Removed: ___________________________
Transformer Asset Number(s) of Units Installed: ______________________________

In-Line Switch (900Amp) ☐ Switch Number(s):____
Dead Blade Switch ☐ Switch Number(s): ____

Lightning Arresters: Distribution Class ☐ Intermediate Class ☐ Station Class ☐ Voltage ________________

Fuse Disconnect Switch (s) (Check One ✓): 34.5kV ☐ 25kV ☐ 100Amp ☐
Phase Changed (Check One ✓): Red ☐ White ☐ Blue☐ Switch No: _______________

Fuse Change ☐ Current Limiter Replaced ☐ Size of Limiter ________amps
Fuse Size Found:_______________ Amps Fuse Installed (Check One ☐): 3amp ☐ 12amp ☐ 15amp ☐
25amp ☐ 30amp ☐ 50amp ☐ 65amp ☐ 80amp ☐ 100amp ☐
140amp ☐ Other: _________

Services Affected ☐ Addresses Affected:____

Bluewater Power Equipment Change Record

Additional Notes:

Sketch Area

Control Room
Operator: ____________________
Date: ______________________

GIS System Editor
____
Date: ______________________

APPENDIX 7

Pole Inspection Report

10/20/2010

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
Orange																
13801	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
20737	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	remove old pole butt
4442	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
13668	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	wood Pins THRU Arm
14330	No	N/A	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4814	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
14224	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
5500	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
Red																
5754	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5756	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
5758	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4224	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4913	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5029	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5031	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5027	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4897	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4893	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4892	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4888	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4887	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4768	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
4770	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4771	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4775	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4778	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4782	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4786	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4804	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Road wood pin thru arm
4806	No	YES	No	YES	No	No	No	No	No	No	No	No	No	OK	No	2woodpinsthru arm check 27-6 x arm for rot
5772	No	YES	No	YES	No	No	No	No	No	No	No	No	No	OK	No	ARM looks rotted wood pins thru arm
5771	No	No	No	YES	No	No	YES	No	No	No	No	No	No	OK	No	
5770	No	YES	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
5769	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
5768	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5916	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5714	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Guy is loose re pull
5912	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Pole rotted no holily wood
5923	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5709	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	wrong locally should be B2136
5385	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5433	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5898	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	Ferns y Pin BAD!
5897	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4792	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4794	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
4798	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
7024	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5776	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4443	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	Road and field Pin thru arm
5781	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14294	No	No	No	No	No	No	No	No	No	No	No	YES	No	OK	No	
14323	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14196	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4791	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
14046	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
7028	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4818	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
14285	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14292	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
13560	No	No	No	No	No	No	No	No	No	YES	No	No	No	OK	No	Repair Corners wire
14350	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13717	No	No	No	No	No	No	No	No	No	No	No	NO	No	Clearance	No	Conductor on x Arm should be removed
13706	No	No	No	No	No	No	No	No	No	No	No	No	No	Broken	No	
14397	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14015	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13572	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14299	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14005	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13672	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
13609	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5298	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13623	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
19834	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
7753	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
7747	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
7742	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
7562	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
7566	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
7568	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
3076	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
3077	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
3079	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14336	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5896	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
5897	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4530	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4532	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4533	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4561	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4578	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4576	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4574	No	No	No	No	No	No	N/A	No	No	No	No	No	No	OK	No	
4572	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
4571	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4570	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4569	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4566	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4563	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4564	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4565	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4597	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4602	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4603	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4604	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4626	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
4628	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4629	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4613	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5433	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5485	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5484	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5438	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5967	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
6518	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
6515	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
6510	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
6509	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	

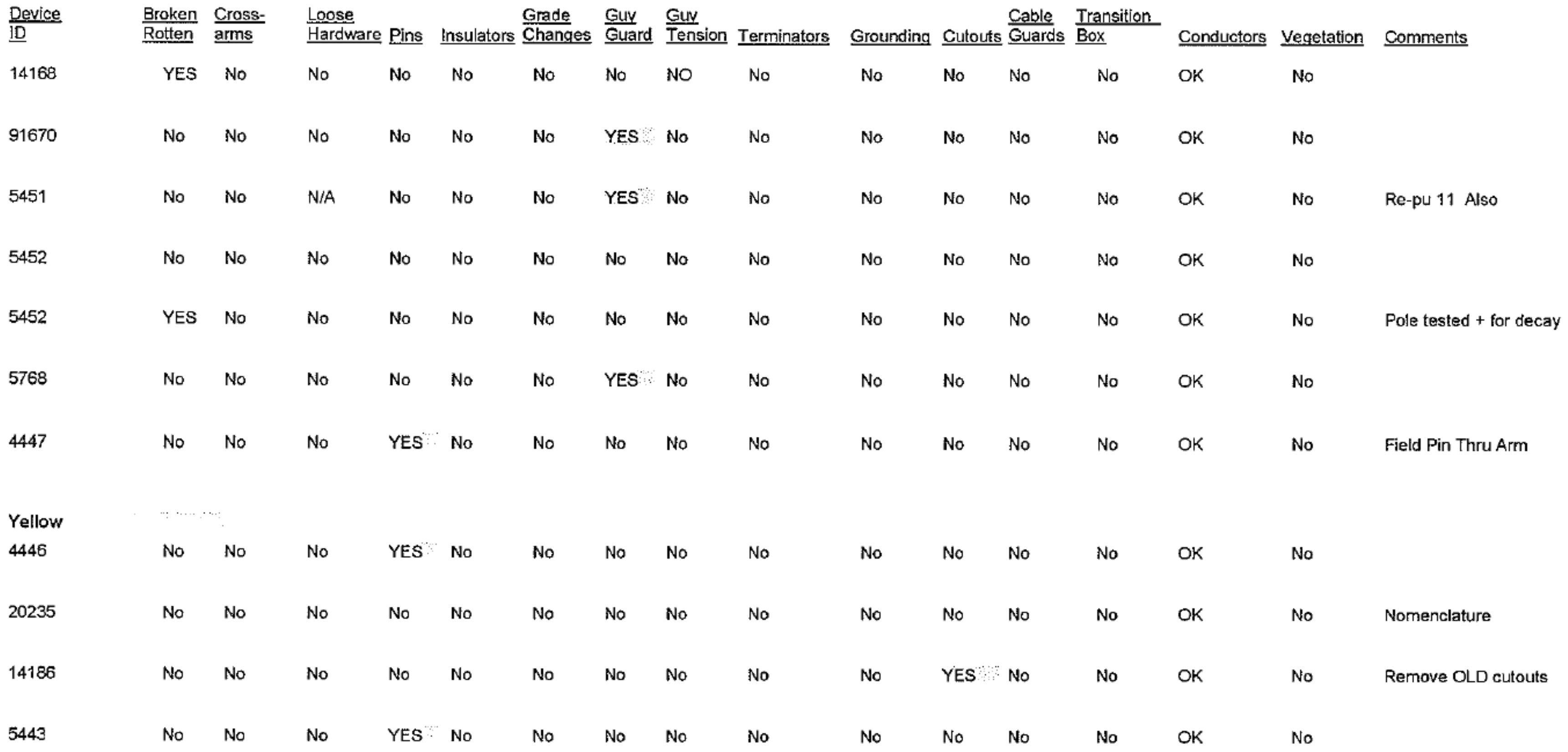
Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
6503	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
6503	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	BEES Nest Bottom E side
13677		YES	No	No	No	No	No	No	No	No	No	No	No	OK	No	27.6 Arm looks Rotten
14126	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14276	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14278	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14314	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	Straighten Pole here.
14318	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4428	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	Center Road field Pins in Bad condition
4426	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4424	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
13099	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
4422	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	TX on this pole critical to change
13549	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13601	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13597	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14253	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
21349	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
14286	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4445	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	Roads, fiend Pins thru arm
4492	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4476	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4909	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
4898	No	No	No	No	No	No	N/A	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
13557	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4899	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4900	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4901	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4902	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4903	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4905	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4906	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4907	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4432	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
14602	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13780	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
4826	No	No	No	No	N/A	No	No	No	No	No	No	No	No	OK	No	10 there 16.2 120/240 B2646 not on this mass 501
13712	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13802	No	No	No	No	No	No	YES	No	No	No	No	YES	No	OK	No	Replace Down Guy
13752	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5476	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14182	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14185	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13755	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Pole Removed here no Pole
5866	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13723	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
13718	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Fuses should be removed this feed to South should
13737	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
13728	No	No	No	No	No	No	No	No	No	No	No	No	No	Broken	No	Remove Poles E Conductor here
13725	No	No	No	No	No	No	No	No	No	No	No	No	No	Broken	No	
13705	No	No	No	No	No	No	No	No	No	No	No	No	No	Broken	No	
5991	No	No	No	No	No	No	YES	N/A	No	No	No	No	No	OK	No	
5759	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
14175	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5760	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5761	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5764	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5480	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
13708	No	No	No	No	No	No	No	No	No	No	No	No	No	Broken	No	
5445	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	



Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
14168	YES	No	No	No	No	No	No	NO	No	No	No	No	No	OK	No	
91670	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
5451	No	No	N/A	No	No	No	YES	No	No	No	No	No	No	OK	No	Re-pu 11 Also
5452	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5452	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Pole tested + for decay
5768	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	
4447	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	Field Pin Thru Arm
Yellow																
4446	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
20235	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Nomenclature
14186	No	No	No	No	No	No	No	No	No	No	YES	No	No	OK	No	Remove OLD cutouts
5443	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
13806	No	No	No	No	No	No	No	No	No	No	No	YES	No	OK	No	
13811	No	No	No	No	No	No	YES	No	No	No	No	No	No	OK	No	remove vines, add guy guard
13747	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	repair sec ug straps
4430	No	No	No	N/A	No	No	No	No	No	No	No	No	No	OK	No	
4440	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4439	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4438	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4444	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4471	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
14135	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	Remove This Pole nothing On It
14311	No	No	No	No	No	No	No	No	No	No	No	YES	No	OK	No	
5899	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
13546	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	wood Pins
13538	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4821	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4822	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4825	No	No	No	N/A	No	No	No	No	No	No	No	No	No	OK	No	
14217	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4816	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
11895	No	No	No	No	No	No	No	No	No	No	No	No	N/A	OK	No	3% Bank here not in Service no nomenclature 16.2 1
5441	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
13544	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
14289	YES	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	
5778	No	No	No	N/A	No	No	No	No	No	No	No	No	No	OK	No	

Device ID	Broken Rotten	Cross-arms	Loose Hardware	Pins	Insulators	Grade Changes	Guy Guard	Guy Tension	Terminators	Grounding	Cutouts	Cable Guards	Transition Box	Conductors	Vegetation	Comments
5779	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
7727	No	No	No	No	No	No	No	No	No	No	No	No	No	OK	No	clean Titus TX installation up
4799	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
4800	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	
5776	No	No	No	YES	No	No	No	No	No	No	No	No	No	OK	No	

Transformer Inspection Report

10/20/2010

DeviceID	Oil Leaks	Rust	Brackets	Arrestors	Bushings	Connectors	Elbows	Lock	Nomenclature	Insulators	Grade Changes	Vegetation	Comments
Red													
B1061	YES	No	No	No	No	No	No	No	No	No	NO	No	TX Leaking OIL Bottom west front
Yellow													
B1068	No	No	No	No	No	No	No	No	YES	No	No	No	

Breaker & Switch Inspection Report

10/20/2010

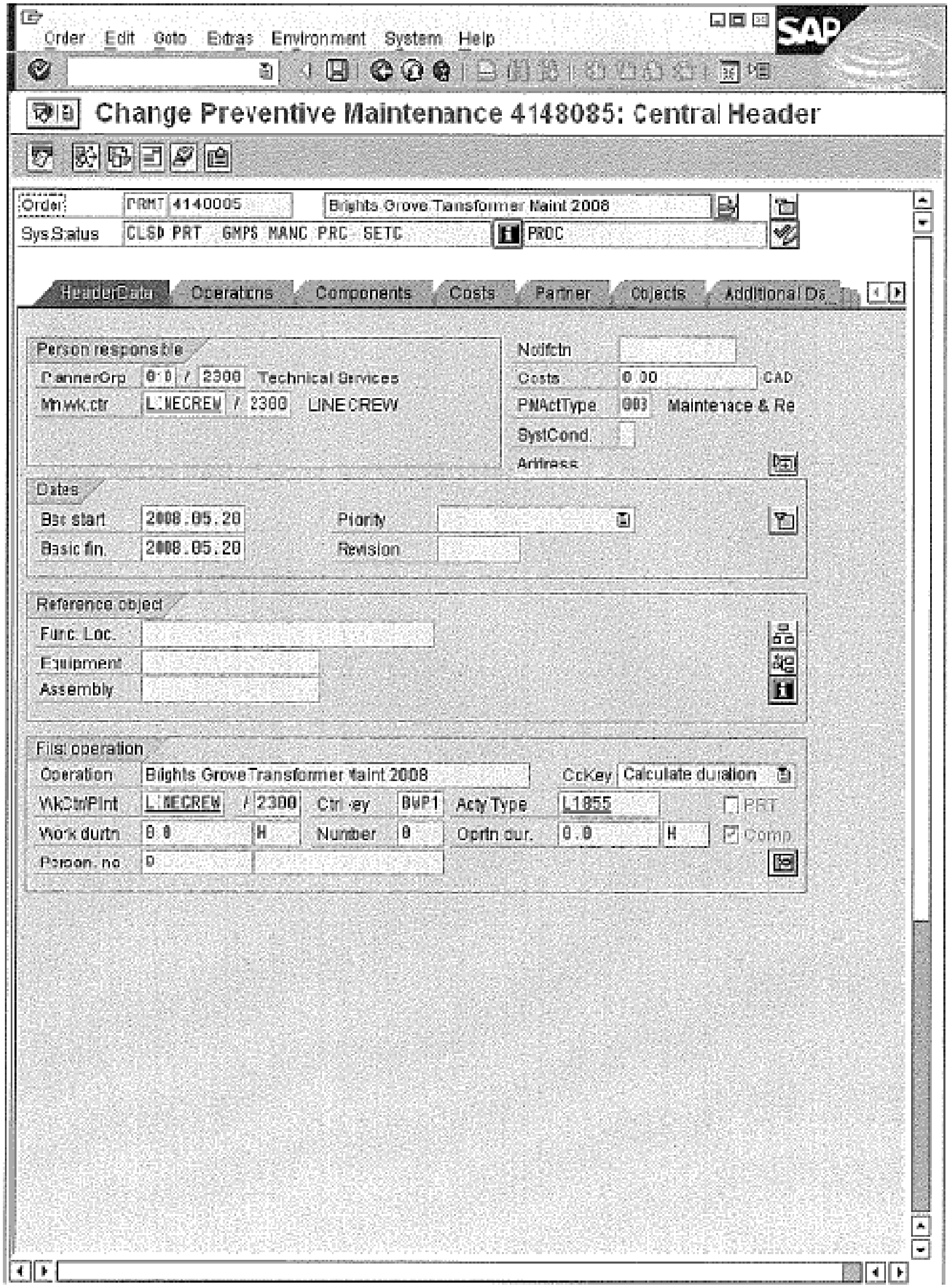
DeviceID	Lightning Arrestor	Connection	Grounding	Bent Broken	Locks	Nomenclature	Vegetation	Comments
Red								
7B44	No	No	No	No	No	No	No	These R fused Switches for Paint B2168

Fused Switch Inspection Report

10/20/20

DeviceID	Lightning Arrestor	Connection	Grounding	Bent Broken	Locks	Nomenclature	Vegetation	Comments

APPENDIX 8



Change Preventive Maintenance 4148085: Central Header

Order: PRMT 4140005 Brights Grove Transformer Maint 2008
Sys.Status: CLSD PRT GMPS MANC PRC SETC PROC

Person responsible
PlannerGrp: 010 / 2300 Technical Services
Mn.wk.ctr: LINECREW / 2300 LINECREW

Notifctn:
Costs: 0.00 CAD
PMActType: 003 Maintenace & Re
SystCond.:
Address

Dates
Bsc start: 2008.05.20
Basic fin.: 2008.05.20
Priority:
Revision:

Reference object
Func. Loc.:
Equipment:
Assembly:

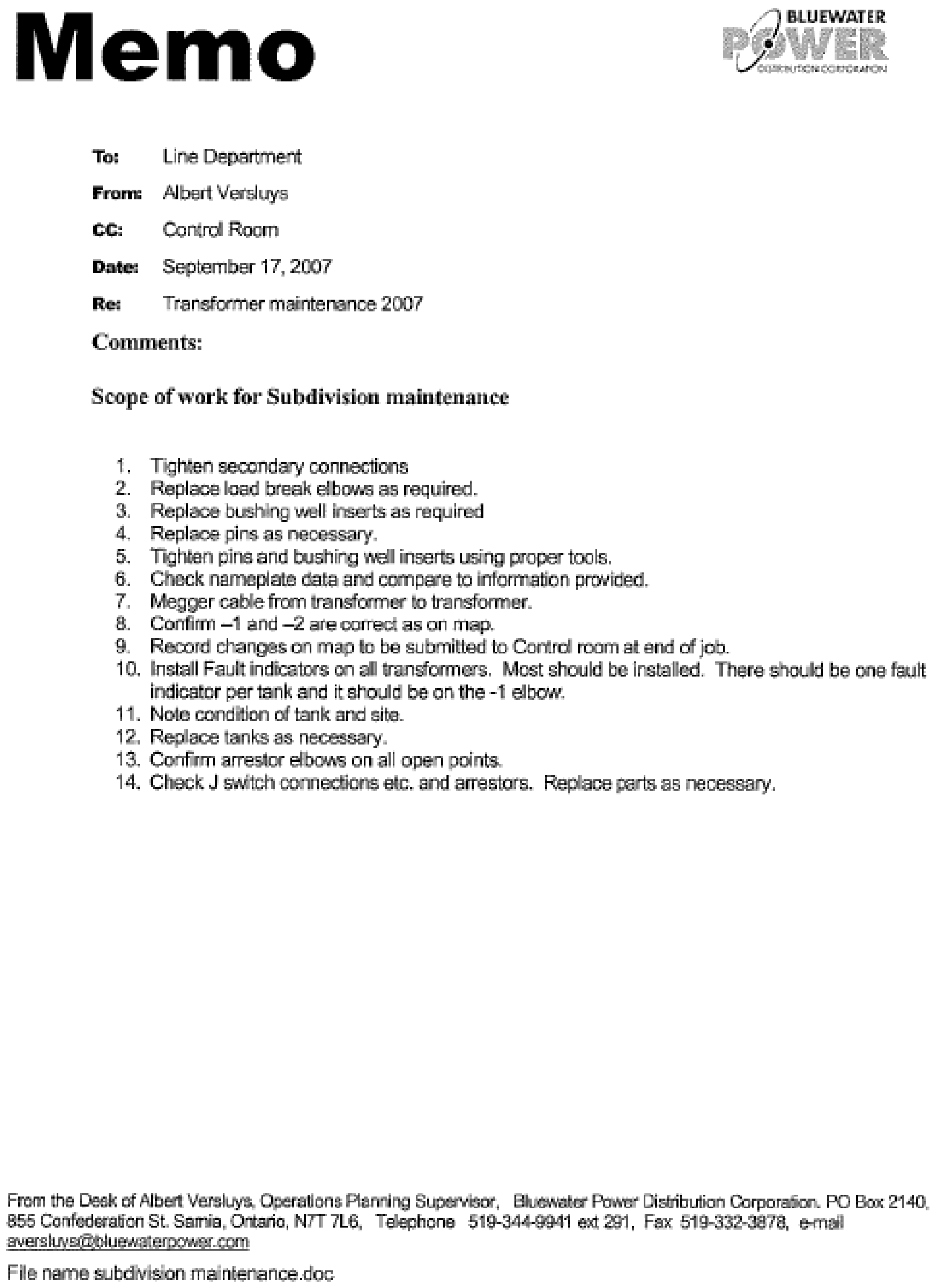
First operation
Operation: Brights Grove Transformer Maint 2008
CcKey: Calculate duration
WkCtr/Plnt: LINECREW / 2300
Ctrl key: BWP1
Acty Type: L1855
☐ PRT
Work durtn: 0.0 H
Number: 0
Oprtn dur.: 0.0 H
☑ Comp
Person. no: 0

APPENDIX 9

Brights Grove Transformer Maint Yellow Highlight were completed in 2007

LOCATION	UNITKVA	LOCAL	SERIALNO	MANUFACTUR	IMP	INT SW	PCB DATE	PCB	PHASE	SEC	TAPPOSITIO	COMMENTS
A3062	100	18378	C95047-2	NS		1	6/8/1995	49	W	120/240V		
A3063	100	18280	BC94110211	CAM TRAN		1	10/11/1994	49	R	120/240V		
A3064	100	18281	BC9410212	CAM TRAN		1	10/11/1994	49	R	120/240V		
A3068	100	5882	274569	MOLONEY	0.10	1			B	120/240V		
A3069	100	5883	274578	MOLONEY	0.10	1			B	120/240V		
A3070	50	9455	89-03E5180-049	WESTINGHOUSE	3.20	1			B	120/240V		
A3071	75		7638-88	MOLONEY		1	11/26/2002	0	B	120/240V		
A3072	75	9457	7838-92	MOLONEY	2.00	1			B	120/240V		
A3073	75	9458	T1834-011	CARTE	3.20	1			B	120/240V		
A3074	100	5793	869807	C.G.E.	1.00	1			W	120/240V		
A3075	100	5794	869812	C.G.E.	1.00	1			W	120/240V		
A3076	75	7406	LU12457	WESTINGHOUSE	1.00	1			W	120/240V		
A3079	100	18310	95J819009	ASEA BROWN BOVERI	2.30	1			B	120/240V		Has Selector switch and fault indicator Maintenance Oct 22, 2007
A3080	100	18315	95J819016	ASEA BROWN BOVERI	2.30	1			B	120/240V		Has Selector switch and fault indicator Maintenance Oct 22, 2007
A3081	100	18314	95J819015	ASEA BROWN BOVERI	2.30	1			B	120/240V		Has Selector switch and fault indicator Maintenance Oct 22, 2007
A3082	100	18311	95J819011	ASEA BROWN BOVERI	2.30	1			B	120/240V		Has Selector switch and fault indicator Maintenance Oct 22, 2007
A3083	100	10057	N1361-13	CARTE	1.00	1			B	120/240V		Maintenance complete Oct 22, 2007
A3084	100	10115	S0936-80	CARTE	1.00	1			B	120/240V		Maintenance complete Oct 22, 2007
A3085	100	10114	S0936-66	CARTE	1.00	1			B	120/240V		Maintenance complete Oct 22, 2007
A3086	100	10113	S0936-60	CARTE	1.00	1			B	120/240V		Maintenance complete Oct 22, 2007
A3087	100	10056	N1361-7	CARTE	1.00	1			B	120/240V		
A3103	100	X130	V0842-005	CARTE	1.00	1			W	120/240V		
A3118	75	1955	L0728-5	CARTE	3.10	1			R	120/240V		
A3119	100	6481	741084171	RTE	2.20	1			W	120/240V		

APPENDIX 10



Memo

To: Line Department

From: Albert Versluys

CC: Control Room

Date: September 17, 2007

Re: Transformer maintenance 2007

Comments:

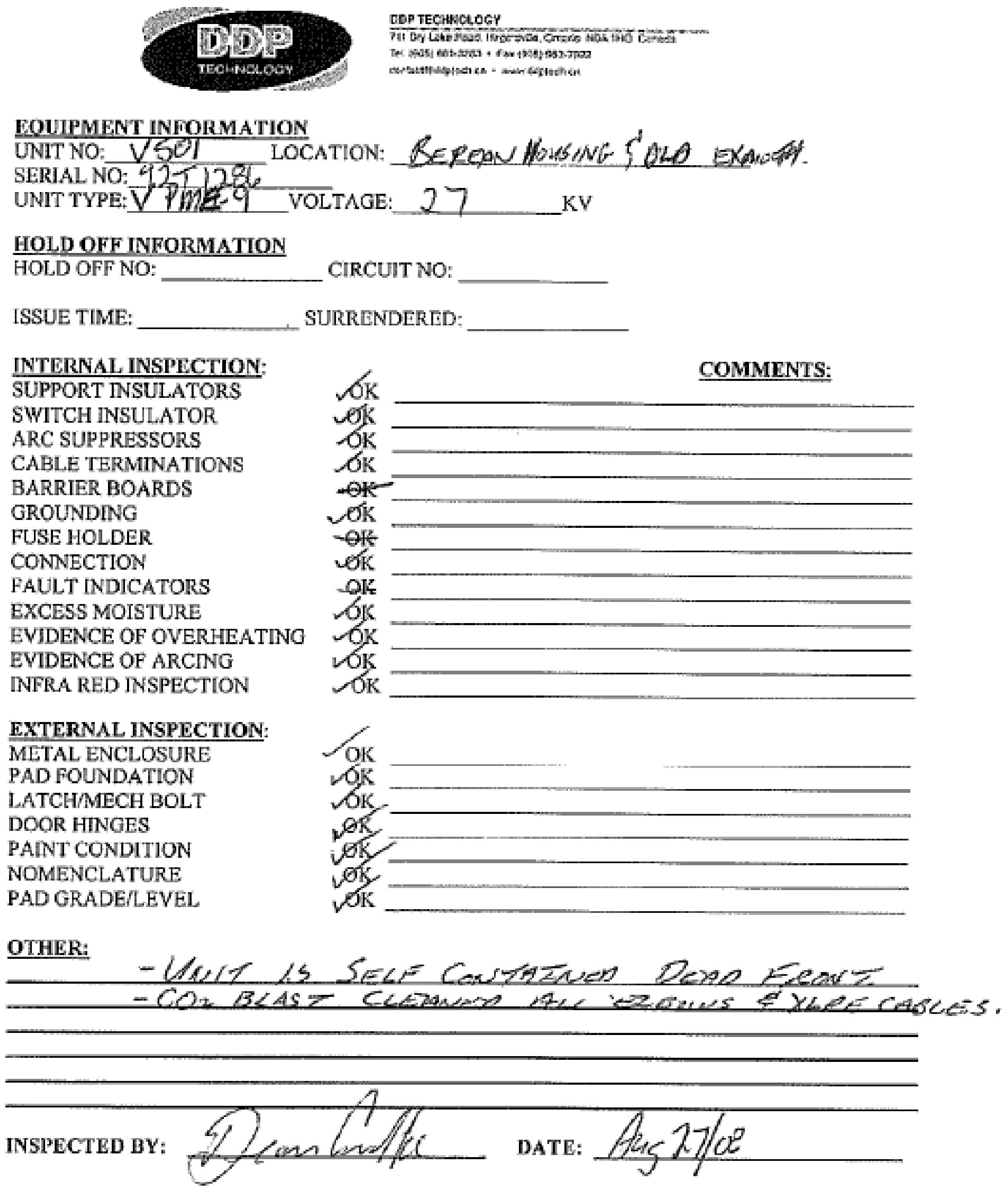
Scope of work for Subdivision maintenance

1. Tighten secondary connections
2. Replace load break elbows as required.
3. Replace bushing well inserts as required
4. Replace pins as necessary.
5. Tighten pins and bushing well inserts using proper tools.
6. Check nameplate data and compare to information provided.
7. Megger cable from transformer to transformer.
8. Confirm –1 and –2 are correct as on map.
9. Record changes on map to be submitted to Control room at end of job.
10. Install Fault indicators on all transformers. Most should be installed. There should be one fault indicator per tank and it should be on the -1 elbow.
11. Note condition of tank and site.
12. Replace tanks as necessary.
13. Confirm arrestor elbows on all open points.
14. Check J switch connections etc. and arrestors. Replace parts as necessary.

From the Desk of Albert Versluys, Operations Planning Supervisor, Bluewater Power Distribution Corporation. PO Box 2140, 855 Confederation St. Sarnia, Ontario, N7T 7L6, Telephone 519-344-9941 ext 291, Fax 519-332-3878, e-mail aversluys@bluewaterpower.com

File name subdivision maintenance.doc

APPENDIX 11



DDP TECHNOLOGY

EQUIPMENT INFORMATION

UNIT NO: V501 LOCATION: BEREAN HOUSING & OLD EXCHANGE.
SERIAL NO: 92T1286
UNIT TYPE: V PME-9 VOLTAGE: 27 KV

HOLD OFF INFORMATION

HOLD OFF NO: ______ CIRCUIT NO: ______

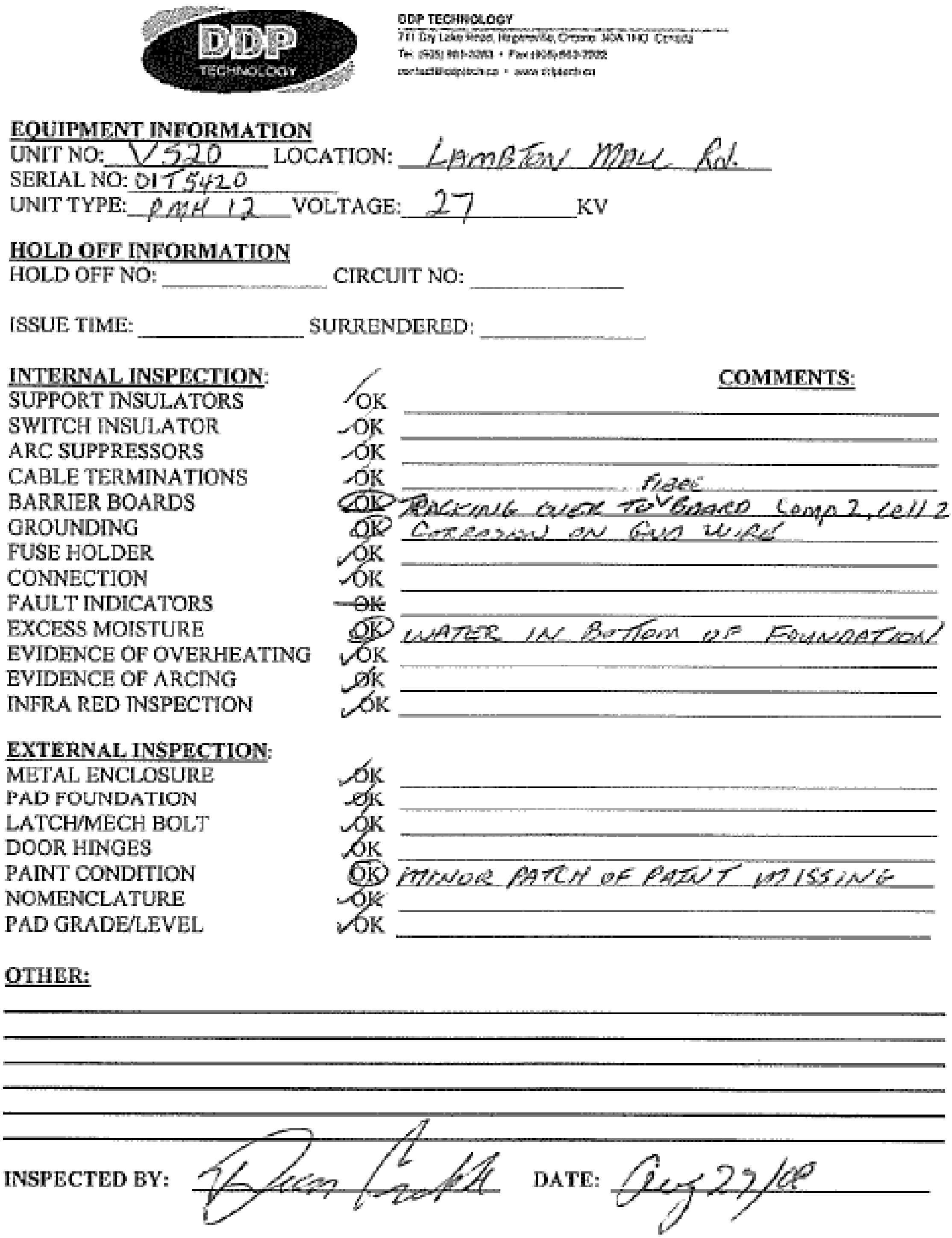
ISSUE TIME: ______ SURRENDERED: ______

INTERNAL INSPECTION:		**COMMENTS:**
SUPPORT INSULATORS	✓ OK	
SWITCH INSULATOR	✓ OK	
ARC SUPPRESSORS	✓ OK	
CABLE TERMINATIONS	✓ OK	
BARRIER BOARDS	~~OK~~	
GROUNDING	✓ OK	
FUSE HOLDER	~~OK~~	
CONNECTION	✓ OK	
FAULT INDICATORS	~~OK~~	
EXCESS MOISTURE	✓ OK	
EVIDENCE OF OVERHEATING	✓ OK	
EVIDENCE OF ARCING	✓ OK	
INFRA RED INSPECTION	✓ OK	
EXTERNAL INSPECTION:		
METAL ENCLOSURE	✓ OK	
PAD FOUNDATION	✓ OK	
LATCH/MECH BOLT	✓ OK	
DOOR HINGES	✓ OK	
PAINT CONDITION	✓ OK	
NOMENCLATURE	✓ OK	
PAD GRADE/LEVEL	✓ OK	

OTHER:

- UNIT IS SELF CONTAINED DEAD FRONT.
- CO_2 BLAST CLEANING ALL ELBOWS & XLPE CABLES.

INSPECTED BY: **DATE:** Aug 27/02



DDP TECHNOLOGY

EQUIPMENT INFORMATION
UNIT NO: V520 LOCATION: LAMBTON MALL Rd.
SERIAL NO: 01T5420
UNIT TYPE: RMH 12 VOLTAGE: 27 KV

HOLD OFF INFORMATION
HOLD OFF NO: ______ CIRCUIT NO: ______

ISSUE TIME: ______ SURRENDERED: ______

INTERNAL INSPECTION:		**COMMENTS:**
SUPPORT INSULATORS	✓ OK	
SWITCH INSULATOR	✓ OK	
ARC SUPPRESSORS	✓ OK	
CABLE TERMINATIONS	✓ OK	
BARRIER BOARDS	[✓ OK]	TRACKING CHECK TO FIBRE BOARD Comp 2, Cell 2
GROUNDING	[✓ OK]	CORROSION ON GUY WIRE
FUSE HOLDER	✓ OK	
CONNECTION	✓ OK	
FAULT INDICATORS	~~OK~~	
EXCESS MOISTURE	[✓ OK]	WATER IN BOTTOM OF FOUNDATION
EVIDENCE OF OVERHEATING	✓ OK	
EVIDENCE OF ARCING	✓ OK	
INFRA RED INSPECTION	✓ OK	
EXTERNAL INSPECTION:		
METAL ENCLOSURE	✓ OK	
PAD FOUNDATION	✓ OK	
LATCH/MECH BOLT	✓ OK	
DOOR HINGES	✓ OK	
PAINT CONDITION	[✓ OK]	MINOR PATCH OF PAINT MISSING
NOMENCLATURE	✓ OK	
PAD GRADE/LEVEL	✓ OK	

OTHER:

INSPECTED BY: DATE: Aug 27/08

APPENDIX 12

Scope of Work for UBE Station Maintenance

Scheduled for Sept 3, 2007

Job Start 8:00 am, end at approximately 4:00 pm

Description of Work

The work will consist of inspection and testing of all equipment owned by Bluewater Power. The work force will consist of 4 Bluewater Power Journeyman lineman. Ainsworth will be working on the switchgear inside UBE's plant. We will have to maintain contact at all times with their representative. We own all the equipment in the outside substation up to the transformer secondary's. The bus duct is owned by UBE. We should be on site ready to isolate at 7:30 am.

UBE REQUIRES T11 AND T14 BACK IN SERVICE BY NOON.

ISOLATION

There will be 2 permits, one in the morning on the entire station and one in the afternoon on the T12 and T13 only. We will provide a guarantee from Ainsworth on the main breakers on each of motor control centers we should be able to lock their mains with our locks.

We will also provide Ainsworth with a supporting Guarantee to allow them to work on the Motor control Centers.

A PC14 work and test will be required for the work that takes place throughout the day.

From 8:00 am to 12:00 noon.

1. Transfer test on high voltage switchgear. After the transformers breakers and the T1A breaker is open, open up the T1-L switch. At this time we can simulate a supply failure from each side and confirm that the equipment transfers. Test the transfer in both directions. Can be simulated from the controls. This will be a live test.
2. Finish off the isolation from the riser fuses located at Blackwell rd.
3. Inspect and megger test incoming cables. Inspect and clean the high voltage switchgear.
4. Inspect and test the 4160 volt switchgear.
5. Megger 4160 volt bus
6. Megger transformer primaries including cables from switchgear.
7. remove neutral from main transformer and megger test with all cables on.
8. Exercise tap changer on T1 and return to position found
9. Disconnect neutral on transformer secondary's and megger test bus duct and transformer secondarys. T11 and T14 must be done before 12:00 noon.
10. Exercise tap changers on T11, T12, T13, and T14.
11. Check and clean T1A, T11 and T14 breakers.
12. Restore service to T11 and T14 by noon.

From 12:00 to approximately 4 pm.

1. remove neutral from transformers T12 and T13
2. Megger bus duct including transformer secondary's
3. Clean and check breakers for T12 and T13.
4. Restore T12 and T13.

APPENDIX 13

BLUEWATER POWER DISTRIBUTION CORPORATION SUBSTATION MAINTENANCE

2010

Prepared by
Albert Versluys
Operations Planning Supervisor
10/2/01

BLUEWATER POWERELECTRIC COMMISSION
SUBSTATION MAINTENANCE
November 2010

Introduction

1.1_ Bluewater Power is a Municipal Electrical Utility which presently serves a total of 32,000 customers in the City of Sarnia, Town of Petrolia, Town of Point Edward Town of Alvinston, Town of Oil Springs and the Town of Watford. The combined land base of this service area is approximately 19,000 hectares.

1.1_ Bluewater Power is also pursuing service agreements with many of the smaller Municipal Utilities in the surrounding area. Through these service agreements, there is a potential for an increase to 55,000 customers and an additional geographic area of approximately 152,000 hectares.

1.2_ Bluewater Power is a progressive Electric Utility that is preparing in earnest for competition in the electrical industry in the year 2000.

1.3_ This RFP is intended to solicit proposals from organizations with documented experience in the maintenance and testing of substation equipment.

2 Project Deliverables and Expected Time Table

2.1 Expected Delivery Date: November 2001

2.2 Full written report within 30 days of completion of this work.

3 Information Required with RFP Submission

3.1 Maximum upset cost ($CDN, including GST) deliverables in the time frame as outlined above in sections 2. Cost for each station separately.
3.2 Company information listing similar installations and references.

4 Station List

M.S.# 3,11,12,13, and 14 (list with addresses attached) for full station maintenance relays excluded.

NOTE. **We have included information on all of our substations in this package. Please price only the stations listed above.**

General

Description

Bluewater Power will be contracting out the substation maintenance for 2001. Our goal is to have a thorough job done on our substations this year. We will complete as many substations as our budget allows and others will be deferred to a later date.

Timing

We have a window of opportunity to perform the work in the spring and fall for most substations. Some substations could be done up to the end of November as the load is not as high. Summer time is impossible due to loading.

Isolations

Bluewater Power will provide all labor required for the isolation of each substation before the contractor arrives on site. Each station will be restored after the contractor has completed his work and another station will be isolated for the next day.

Contractor

The contractor will bring sufficient staff to complete each station in 1 day. Our day is from 7:30 am to 4:00 pm. Should the work carry into a second day; the station should be left so it can be restored quickly in an emergency.

Supervision

Bluewater Power will provide one of our staff to stay with the contractor and provide assistance as required.

Hours of work

Hours of work are from 7:30 am to 4:00 pm Monday to Friday for our regular staff.

Information

Information on the relays, breakers, and substations one lines have been provided in this package however it is **strongly recommended that site visits be made** as the information is not complete.

Site visits

Contact Albert Versluys for a site visit and/or additional information.
At phone 519-344-9941 ext 291 fax at 519-332-3878, e-mail aversluys@bluewaterpower.com

Work excluded

1. Transformer Ratio
2. Oil Sampling (already completed)
3. Hypoting of cables

No tap changer operations

SCOPE OF WORK FOR STATION MAINTENANCE

SAFETY **February 9, 1999**

1. **CONFIRM ALL OF THE ISOLATION POINTS WITH ALL PERSONNEL**
2. **CHECK FOR POTENTIAL**
3. **APPLY GROUNDS AS REQUIRED**

Outdoor switchgear.

1. Incoming cables.
   a. Megger cables at 5 kv dc and record results.
   b. Check terminators at both ends for damage.
   c. Inspect lightning arresters.
   d. Inspect base of pole box where applicable.
2. Outdoor switchgear.
   a. Check alignment of switch.
   b. Lubricate pivot points as required.
   c. Clean contacts.
   d. Check general condition.

3. Transformer.
   a. Check condition of transformer.
   b. Check primary and secondary bushings.
   c. Clean insulators.
   d. Check for leaks.
   e. Check ground connections.
   f. Operate transformer fans.
   11 Perform dissipation factor test.

   Yard
   1a Perform ground grid inspection and testing.

Indoor Switchgear

1. Switchgear.
   a. Remove all of the back covers.
   b. Inspect terminations.
   c. Check ct connections.
   d. Check for tracking.
   e. Remove front covers to inspect the bus.
   f. Check tightness of all control wiring.
   g. Megger test cables from switchgear to transformer secondary.
   (requires removing pts and XO connection on the transformer.)

h. Megger the 4 kv bus. (requires the removal of the bus pts.)

Breakers.

a. Remove arc chute covers from the back of the breaker.
b. Inspect contacts and clean as necessary
c. Remove mechanism covers and check all of the linkages.
d. Inspect and clean the control contacts on the breaker.
e. Operate the breaker from the test supply in the station.
f. Inspect the contact gap on the main contacts to determine the correct contact pressure.
g. Install all of the covers back on the breaker.
h. Megger the breaker (at 5000 volts dc)contacts phase to ground in the:
Closed position to grd and phase to phase.
Open position across the open contacts.
Record the results
i. Megger all of the control wiring at 1000 volts dc.
from the control contact block on the breaker (all should be clear from grd.)

3. Trip tests.

a. Roll the breaker into the cell and install the test jumper to the breaker.
b. Remove the covers from the relays.
c. Close the breaker from the local control. (make sure the reclosure is blocked on the local control.)
d. Trip the breaker with by rotating the disk on the over current relays.
e. reclose and trip the breaker by lifting the instantaneous part of the relay.
f. Complete all of the trips.
g. Unblock the reclosure locally and from the SCADA
f. Close the breaker and leave closed for more than 20 seconds.
h. Operate one of the over current relays.
i. The breaker should reclose immediately.
j. Operate one of the over current relays immediately.
k. The breaker should trip and stay off. (if the trip is activated within 15 seconds).
l. have the control room close and open the breaker from the SCADA system.
m. Have the control room block and unblock. the reclosure and observe the operation of the small control relay on the door.

Other testing.

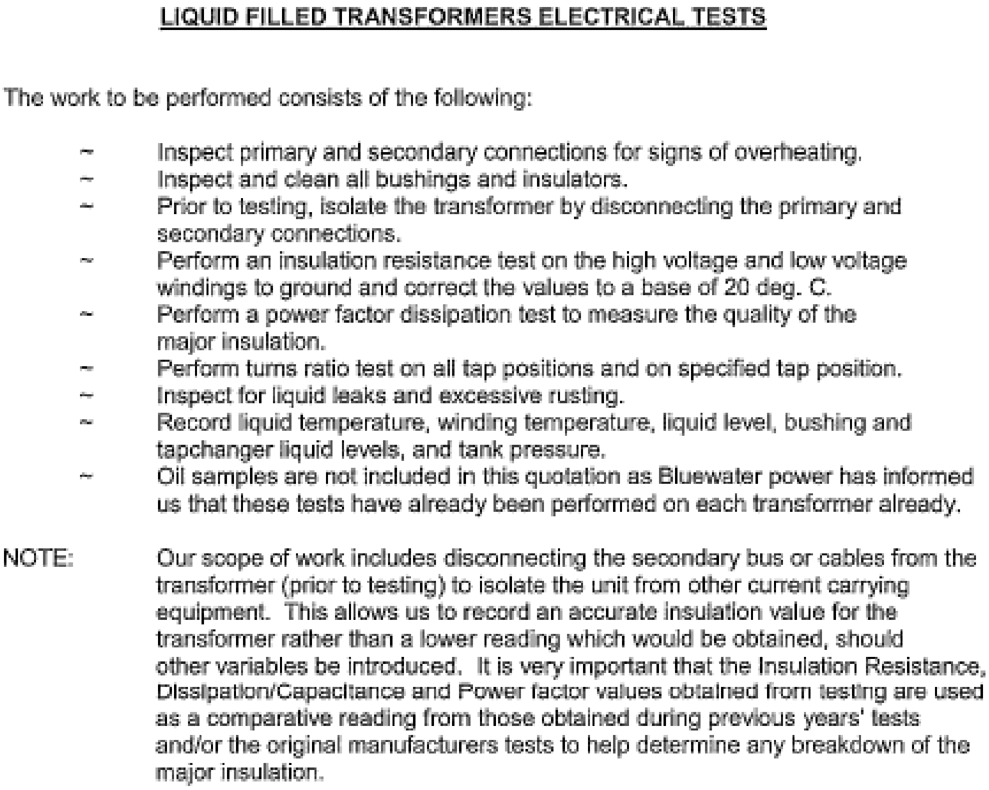
1a Relay calibration and testing. Calibrate all overcurrent and reclosure relays
1b Calibrate SCADA transducers. Our transducers are 0 to 5 amp in and 0 to 1 ma out. Or 0 to 5 volts dc into the SCADA RTU=s

Do not include.

11 High Pot testing
12 Transformer Ratios
13 Do not operate Tap changers.

Substation list with addresses

M.S. # 3	**773 Wellington**
M.S. # 11	**999 Indian Rd.**
M.S. # 12	**936 Maxwell St.**
M.S. # 13	**1486 Colborne, North of Charlesworth**
M.S. # 14	**855 Confederation behind Sarnia Hydro=s work centre.**



LIQUID FILLED TRANSFORMERS ELECTRICAL TESTS

The work to be performed consists of the following:

~ Inspect primary and secondary connections for signs of overheating.
~ Inspect and clean all bushings and insulators.
~ Prior to testing, isolate the transformer by disconnecting the primary and secondary connections.
~ Perform an insulation resistance test on the high voltage and low voltage windings to ground and correct the values to a base of 20 deg. C.
~ Perform a power factor dissipation test to measure the quality of the major insulation.
~ Perform turns ratio test on all tap positions and on specified tap position.
~ Inspect for liquid leaks and excessive rusting.
~ Record liquid temperature, winding temperature, liquid level, bushing and tapchanger liquid levels, and tank pressure.
~ Oil samples are not included in this quotation as Bluewater power has informed us that these tests have already been performed on each transformer already.

NOTE: Our scope of work includes disconnecting the secondary bus or cables from the transformer (prior to testing) to isolate the unit from other current carrying equipment. This allows us to record an accurate insulation value for the transformer rather than a lower reading which would be obtained, should other variables be introduced. It is very important that the Insulation Resistance, Dissipation/Capacitance and Power factor values obtained from testing are used as a comparative reading from those obtained during previous years' tests and/or the original manufacturers tests to help determine any breakdown of the major insulation.

TDL-2

HIGH VOLTAGE BREAKERS

ENGINEERING INSPECTION AND TESTING PROGRAMME

The work to be performed consists of the following:

A Visual and Mechanical Inspection

~ Verify that cell mechanical interlocks preclude the breaker being removed or restored to the operating position with the breaker contacts closed.

~ Remove the breaker from the cell, dust cubicle and check the tightness of all control wiring.

~ Vacuum and dust circuit breakers.

~ Check power and control stabs.

~ Check porcelain and insulation for cracks and holes.

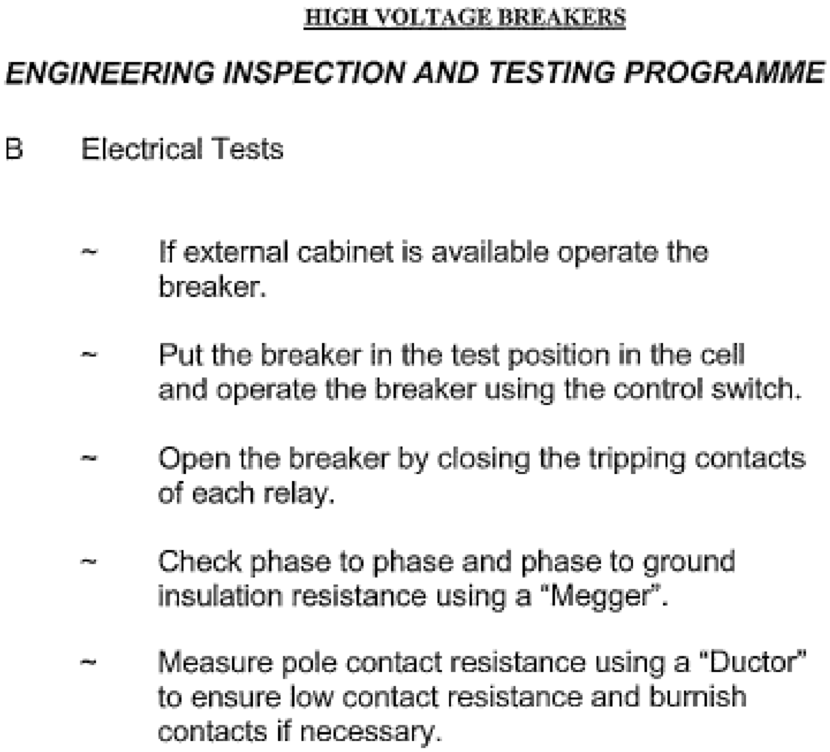
~ Check wear mark indicators to ensure contact integrity.

~ Open and close the breaker a minimum of three times to check for friction and binding.

~ Manually close breakers and check contacts for alignment and mating.

~ Lubricate in accordance with manufacturers' recommendations.

~ Check each phase's Vacuum Bottle integrity with an AC Vacuum Bottle Tester.



HIGH VOLTAGE BREAKERS

ENGINEERING INSPECTION AND TESTING PROGRAMME

B Electrical Tests

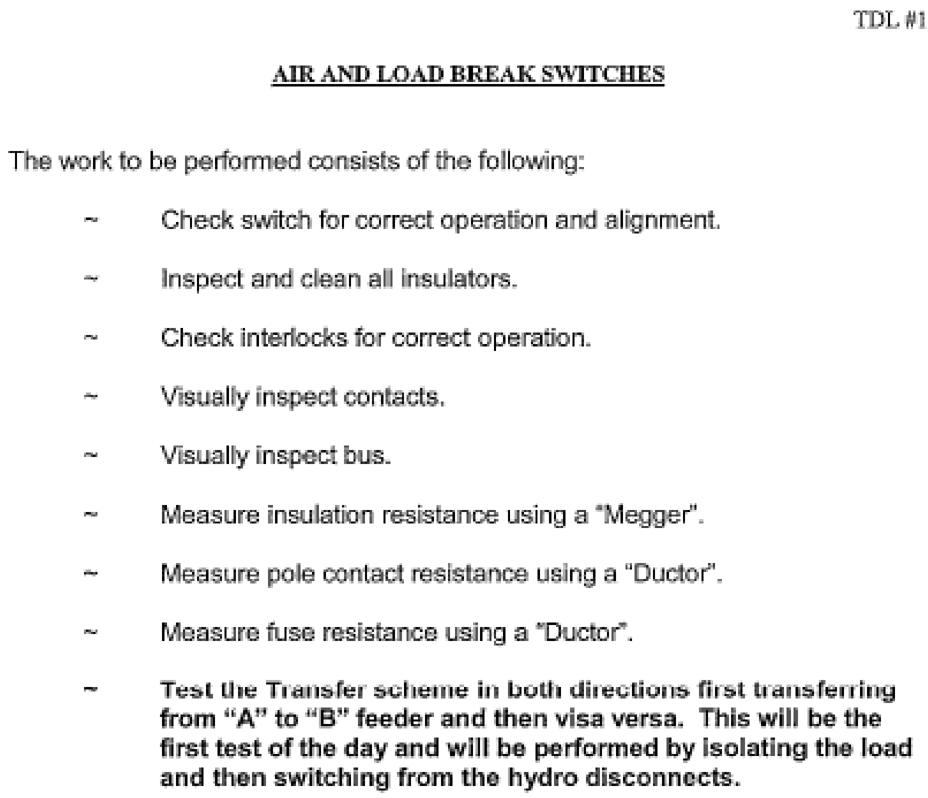
~ If external cabinet is available operate the breaker.

~ Put the breaker in the test position in the cell and operate the breaker using the control switch.

~ Open the breaker by closing the tripping contacts of each relay.

~ Check phase to phase and phase to ground insulation resistance using a "Megger".

~ Measure pole contact resistance using a "Ductor" to ensure low contact resistance and burnish contacts if necessary.



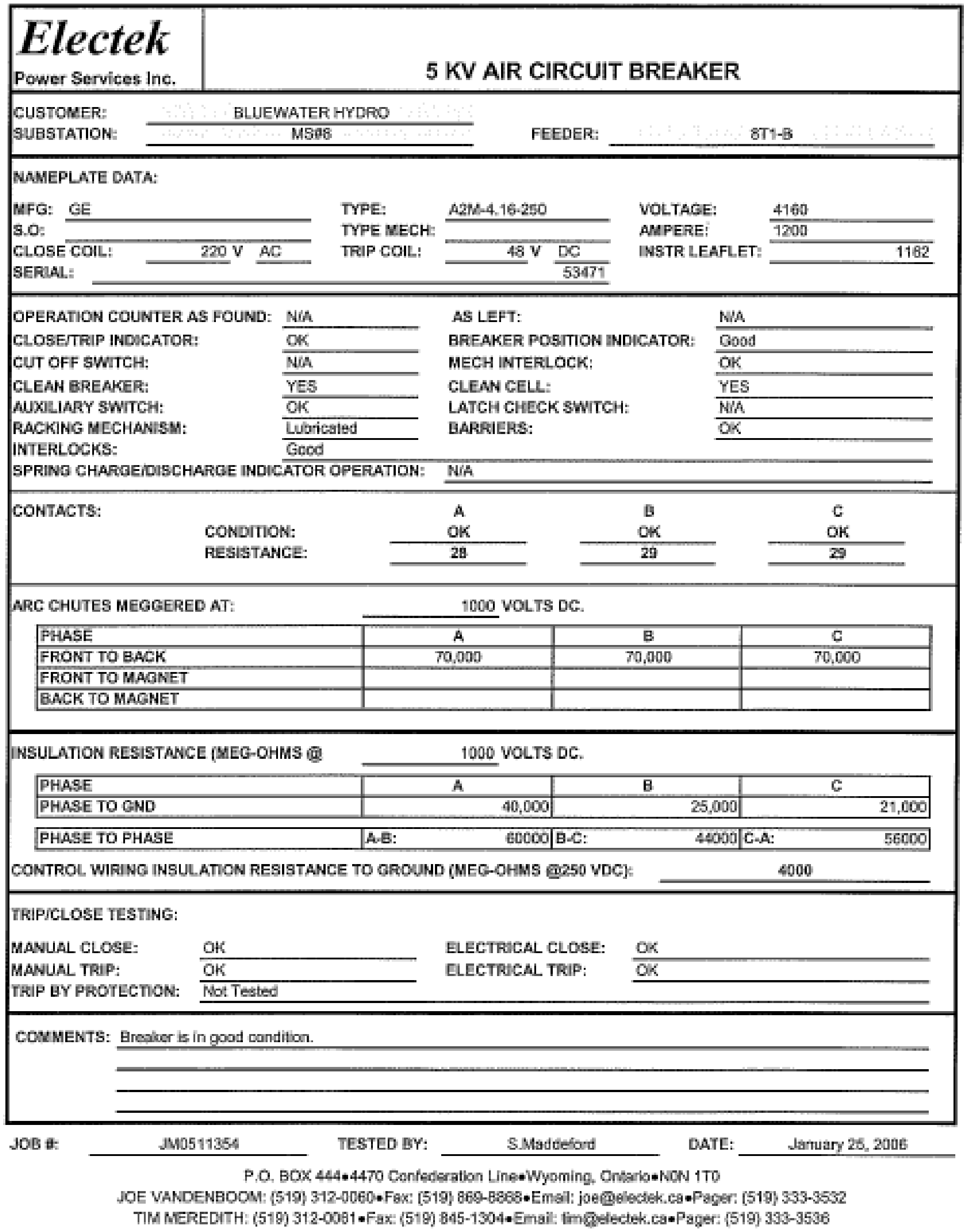
TDL #1

AIR AND LOAD BREAK SWITCHES

The work to be performed consists of the following:

- Check switch for correct operation and alignment.
- Inspect and clean all insulators.
- Check interlocks for correct operation.
- Visually inspect contacts.
- Visually inspect bus.
- Measure insulation resistance using a "Megger".
- Measure pole contact resistance using a "Ductor".
- Measure fuse resistance using a "Ductor".
- **Test the Transfer scheme in both directions first transferring from "A" to "B" feeder and then visa versa. This will be the first test of the day and will be performed by isolating the load and then switching from the hydro disconnects.**

APPENDIX 14



Electek
Power Services Inc.

5 KV AIR CIRCUIT BREAKER

CUSTOMER: BLUEWATER HYDRO
SUBSTATION: MS#6
FEEDER: 8T1-B

NAMEPLATE DATA:

MFG:	GE	TYPE:	A2M-4.16-250	VOLTAGE:	4160
S.O:		TYPE MECH:		AMPERE:	1200
CLOSE COIL:	220 V AC	TRIP COIL:	48 V DC	INSTR LEAFLET:	1182
SERIAL:	53471				

OPERATION COUNTER AS FOUND:	N/A	AS LEFT:	N/A
CLOSE/TRIP INDICATOR:	OK	BREAKER POSITION INDICATOR:	Good
CUT OFF SWITCH:	N/A	MECH INTERLOCK:	OK
CLEAN BREAKER:	YES	CLEAN CELL:	YES
AUXILIARY SWITCH:	OK	LATCH CHECK SWITCH:	N/A
RACKING MECHANISM:	Lubricated	BARRIERS:	OK
INTERLOCKS:	Good		

SPRING CHARGE/DISCHARGE INDICATOR OPERATION: N/A

CONTACTS:

	A	B	C
CONDITION:	OK	OK	OK
RESISTANCE:	28	29	29

ARC CHUTES MEGGERED AT: 1000 VOLTS DC.

PHASE	A	B	C
FRONT TO BACK	70,000	70,000	70,000
FRONT TO MAGNET			
BACK TO MAGNET			

INSULATION RESISTANCE (MEG-OHMS @ 1000 VOLTS DC.

PHASE	A	B	C
PHASE TO GND	40,000	25,000	21,000

PHASE TO PHASE	A-B:	60000	B-C:	44000	C-A:	56000

CONTROL WIRING INSULATION RESISTANCE TO GROUND (MEG-OHMS @250 VDC): 4000

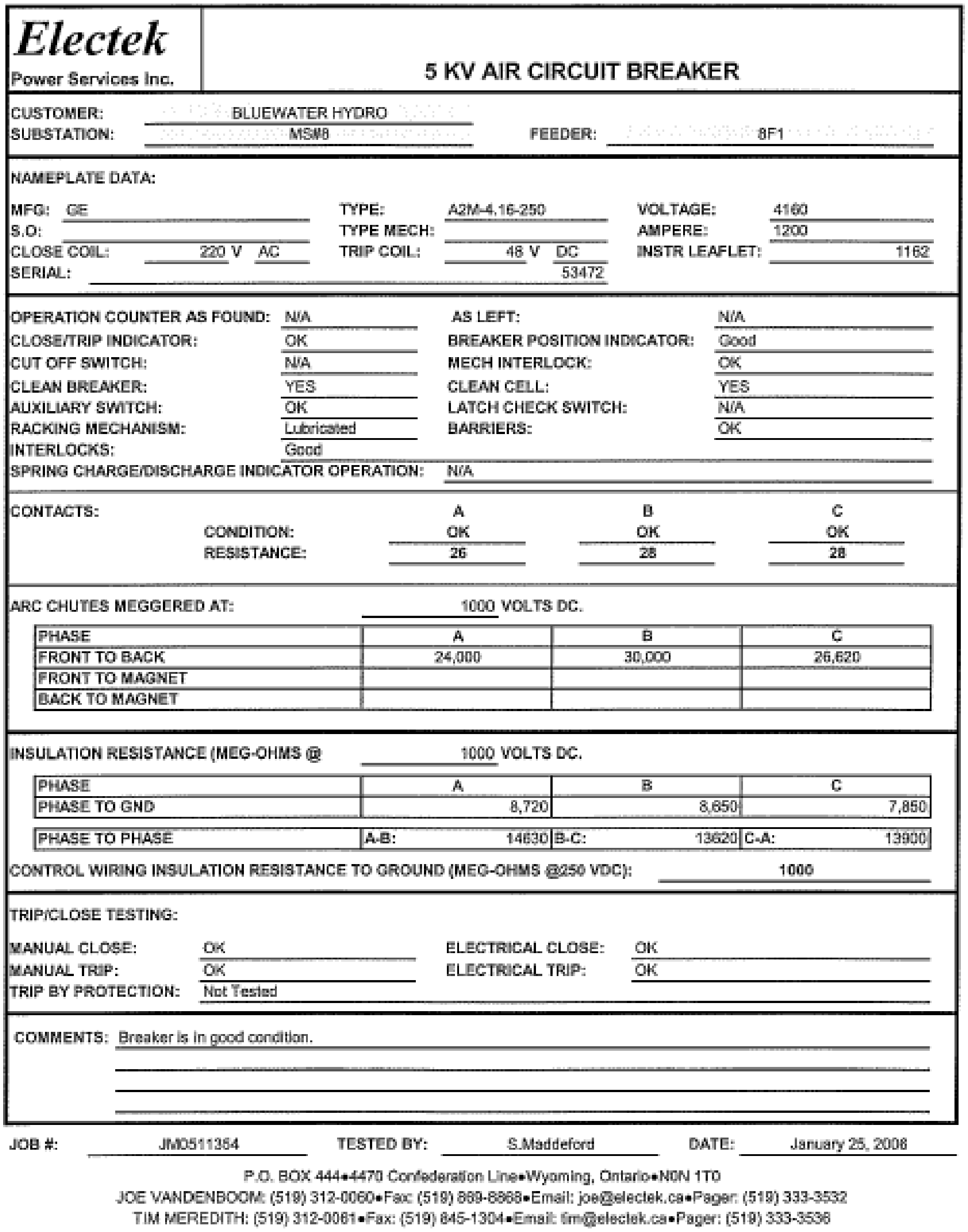
TRIP/CLOSE TESTING:

MANUAL CLOSE:	OK	ELECTRICAL CLOSE:	OK
MANUAL TRIP:	OK	ELECTRICAL TRIP:	OK
TRIP BY PROTECTION:	Not Tested		

COMMENTS: Breaker is in good condition.

JOB #: JM0511354 TESTED BY: S.Maddeford DATE: January 25, 2006

P.O. BOX 444•4470 Confederation Line•Wyoming, Ontario•N0N 1T0
JOE VANDENBOOM: (519) 312-0060•Fax: (519) 869-8868•Email: joe@electek.ca•Pager: (519) 333-3532
TIM MEREDITH: (519) 312-0061•Fax: (519) 845-1304•Email: tim@electek.ca•Pager: (519) 333-3536



Electek
Power Services Inc.

5 KV AIR CIRCUIT BREAKER

CUSTOMER: BLUEWATER HYDRO
SUBSTATION: MS#8
FEEDER: 8F1

NAMEPLATE DATA:

MFG:	GE	TYPE:	A2M-4.16-250	VOLTAGE:	4160
S.O:		TYPE MECH:		AMPERE:	1200
CLOSE COIL:	220 V AC	TRIP COIL:	48 V DC	INSTR LEAFLET:	1162
SERIAL:	53472				

OPERATION COUNTER AS FOUND:	N/A	AS LEFT:	N/A
CLOSE/TRIP INDICATOR:	OK	BREAKER POSITION INDICATOR:	Good
CUT OFF SWITCH:	N/A	MECH INTERLOCK:	OK
CLEAN BREAKER:	YES	CLEAN CELL:	YES
AUXILIARY SWITCH:	OK	LATCH CHECK SWITCH:	N/A
RACKING MECHANISM:	Lubricated	BARRIERS:	OK
INTERLOCKS:	Good		

SPRING CHARGE/DISCHARGE INDICATOR OPERATION: N/A

CONTACTS:

	A	B	C
CONDITION:	OK	OK	OK
RESISTANCE:	26	28	28

ARC CHUTES MEGGERED AT: 1000 VOLTS DC.

PHASE	A	B	C
FRONT TO BACK	24,000	30,000	26,620
FRONT TO MAGNET			
BACK TO MAGNET			

INSULATION RESISTANCE (MEG-OHMS @ 1000 VOLTS DC.

PHASE	A	B	C
PHASE TO GND	8,720	8,650	7,850
PHASE TO PHASE	A-B: 14630	B-C: 13620	C-A: 13900

CONTROL WIRING INSULATION RESISTANCE TO GROUND (MEG-OHMS @250 VDC): 1000

TRIP/CLOSE TESTING:

MANUAL CLOSE:	OK	ELECTRICAL CLOSE:	OK
MANUAL TRIP:	OK	ELECTRICAL TRIP:	OK
TRIP BY PROTECTION:	Not Tested		

COMMENTS: Breaker is in good condition.

JOB #: JM0511354 TESTED BY: S.Maddeford DATE: January 25, 2006

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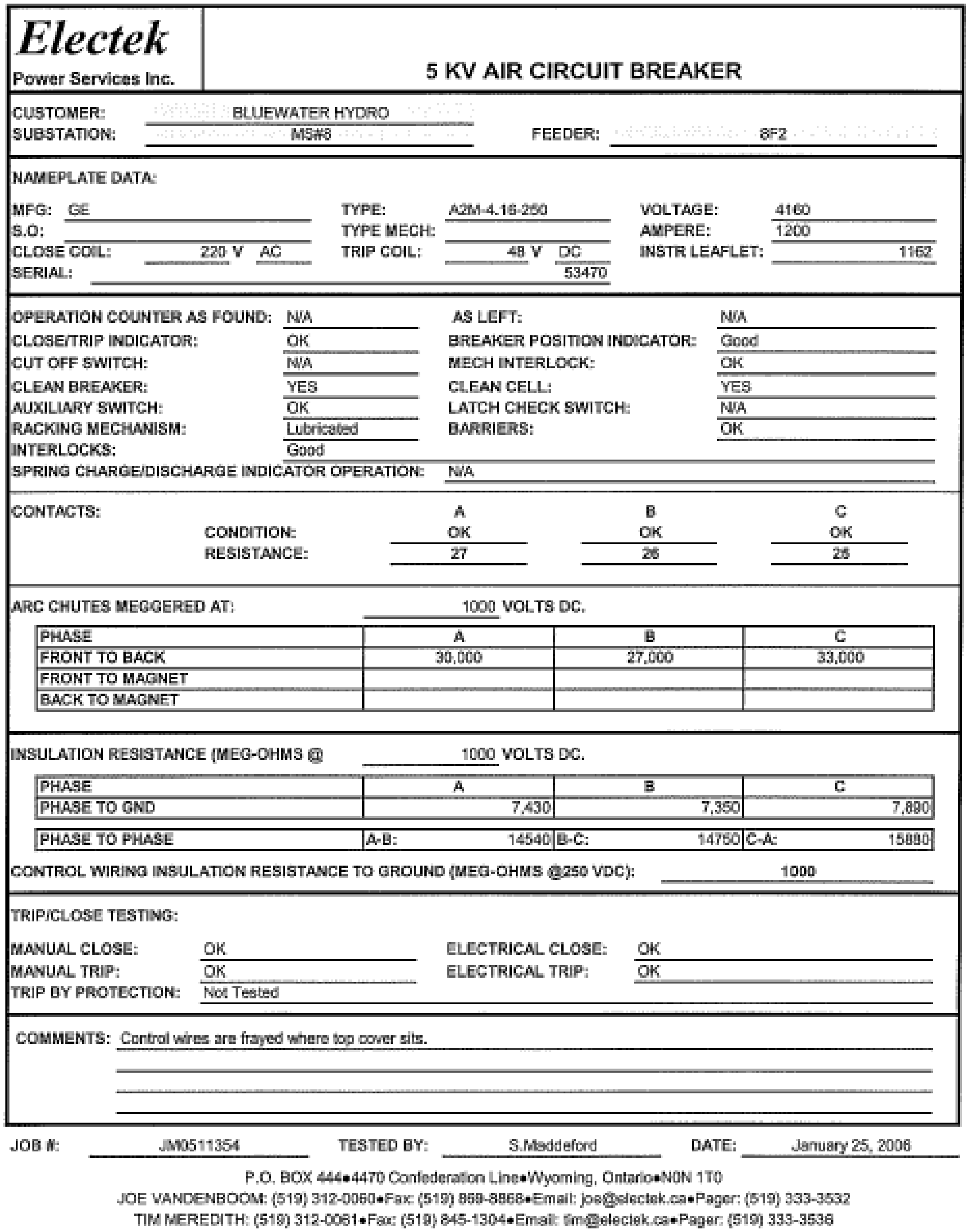

Electek
Power Services Inc.

5 KV AIR CIRCUIT BREAKER

CUSTOMER: BLUEWATER HYDRO
SUBSTATION: MS#8
FEEDER: 8F2

NAMEPLATE DATA:

MFG: GE
S.O:
CLOSE COIL: 220 V AC
SERIAL: 53470
TYPE: A2M-4.16-250
TYPE MECH:
TRIP COIL: 48 V DC
VOLTAGE: 4160
AMPERE: 1200
INSTR LEAFLET: 1162

OPERATION COUNTER AS FOUND: N/A
CLOSE/TRIP INDICATOR: OK
CUT OFF SWITCH: N/A
CLEAN BREAKER: YES
AUXILIARY SWITCH: OK
RACKING MECHANISM: Lubricated
INTERLOCKS: Good
AS LEFT: N/A
BREAKER POSITION INDICATOR: Good
MECH INTERLOCK: OK
CLEAN CELL: YES
LATCH CHECK SWITCH: N/A
BARRIERS: OK
SPRING CHARGE/DISCHARGE INDICATOR OPERATION: N/A

CONTACTS:

	A	B	C
CONDITION:	OK	OK	OK
RESISTANCE:	27	26	26

ARC CHUTES MEGGERED AT: 1000 VOLTS DC.

PHASE	A	B	C
FRONT TO BACK	30,000	27,000	33,000
FRONT TO MAGNET			
BACK TO MAGNET			

INSULATION RESISTANCE (MEG-OHMS @ 1000 VOLTS DC.

PHASE	A	B	C
PHASE TO GND	7,430	7,350	7,890

PHASE TO PHASE	A-B:	14540	B-C:	14750	C-A:	15880

CONTROL WIRING INSULATION RESISTANCE TO GROUND (MEG-OHMS @250 VDC): 1000

TRIP/CLOSE TESTING:

MANUAL CLOSE: OK
MANUAL TRIP: OK
TRIP BY PROTECTION: Not Tested
ELECTRICAL CLOSE: OK
ELECTRICAL TRIP: OK

COMMENTS: Control wires are frayed where top cover sits.

JOB #: JM0511354
TESTED BY: S.Maddeford
DATE: January 25, 2006

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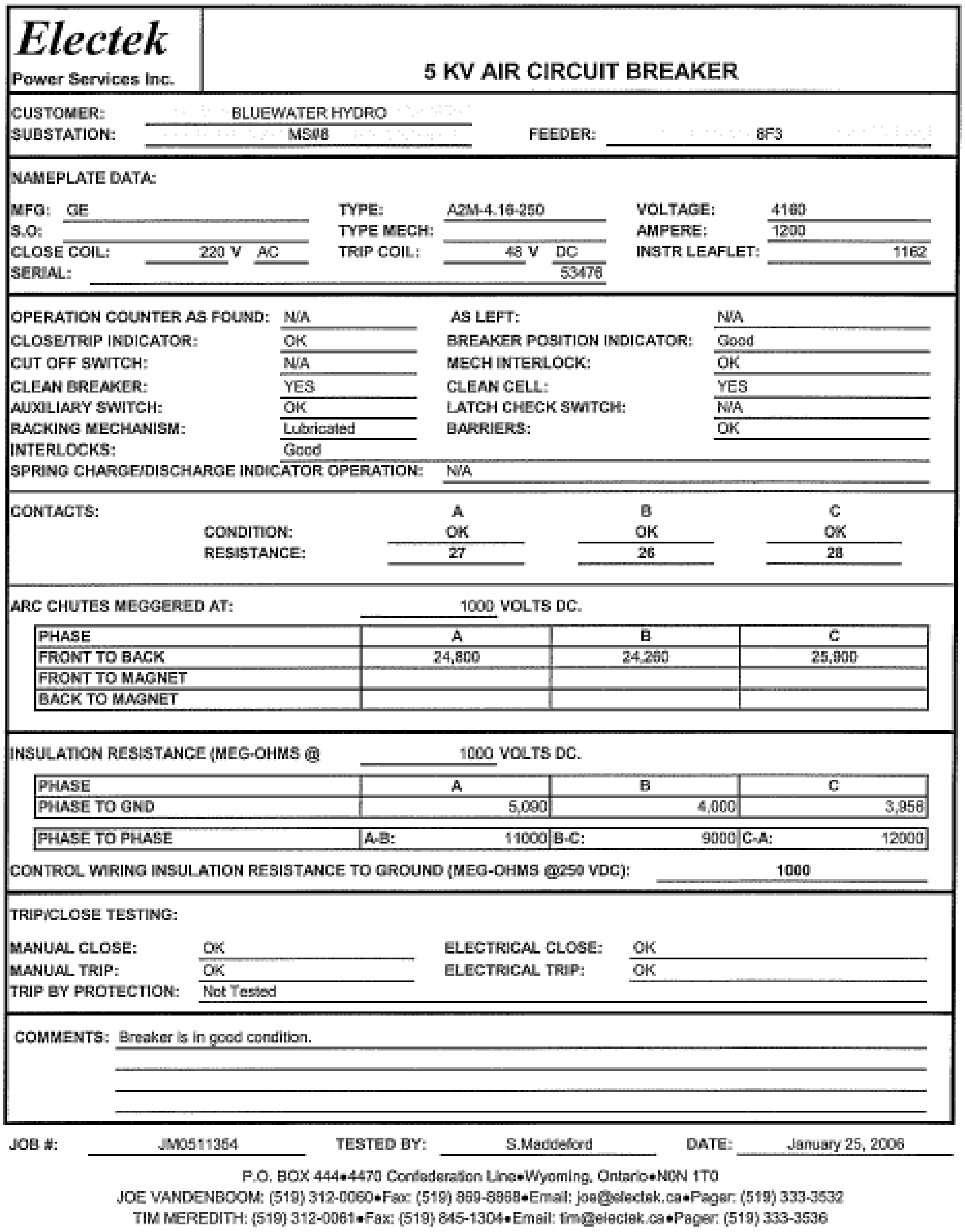

Electek
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5 KV AIR CIRCUIT BREAKER

CUSTOMER: BLUEWATER HYDRO
SUBSTATION: MS#8 FEEDER: 8F3

NAMEPLATE DATA:

MFG: GE TYPE: A2M-4.16-250 VOLTAGE: 4160
S.O: TYPE MECH: AMPERE: 1200
CLOSE COIL: 220 V AC TRIP COIL: 48 V DC INSTR LEAFLET: 1162
SERIAL: 53476

OPERATION COUNTER AS FOUND: N/A AS LEFT: N/A
CLOSE/TRIP INDICATOR: OK BREAKER POSITION INDICATOR: Good
CUT OFF SWITCH: N/A MECH INTERLOCK: OK
CLEAN BREAKER: YES CLEAN CELL: YES
AUXILIARY SWITCH: OK LATCH CHECK SWITCH: N/A
RACKING MECHANISM: Lubricated BARRIERS: OK
INTERLOCKS: Good
SPRING CHARGE/DISCHARGE INDICATOR OPERATION: N/A

CONTACTS:	A	B	C
CONDITION:	OK	OK	OK
RESISTANCE:	27	26	28

ARC CHUTES MEGGERED AT: 1000 VOLTS DC.

PHASE	A	B	C
FRONT TO BACK	24,800	24,260	25,900
FRONT TO MAGNET			
BACK TO MAGNET			

INSULATION RESISTANCE (MEG-OHMS @ 1000 VOLTS DC.

PHASE	A	B	C
PHASE TO GND	5,090	4,000	3,956

PHASE TO PHASE	A-B:	11000	B-C:	9000	C-A:	12000

CONTROL WIRING INSULATION RESISTANCE TO GROUND (MEG-OHMS @250 VDC): 1000

TRIP/CLOSE TESTING:

MANUAL CLOSE: OK ELECTRICAL CLOSE: OK
MANUAL TRIP: OK ELECTRICAL TRIP: OK
TRIP BY PROTECTION: Not Tested

COMMENTS: Breaker is in good condition.

JOB #: JM0511354 TESTED BY: S.Maddeford DATE: January 25, 2006

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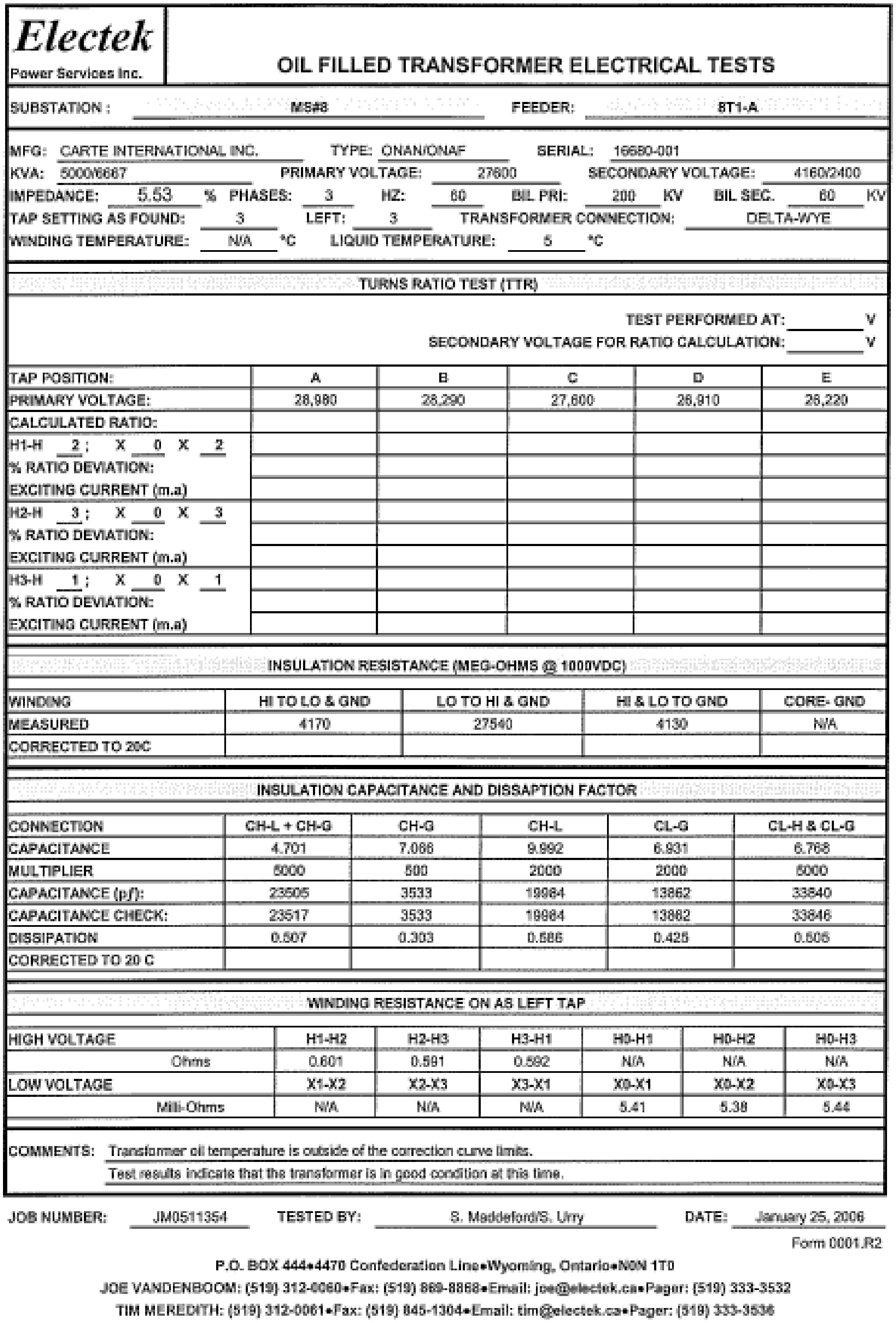

Electek
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OIL FILLED TRANSFORMER ELECTRICAL TESTS

SUBSTATION : MS#8 FEEDER: 8T1-A

MFG: CARTE INTERNATIONAL INC. TYPE: ONAN/ONAF SERIAL: 16680-001
KVA: 5000/6667 PRIMARY VOLTAGE: 27600 SECONDARY VOLTAGE: 4160/2400
IMPEDANCE: 5.53 % PHASES: 3 HZ: 60 BIL PRI: 200 KV BIL SEC. 60 KV
TAP SETTING AS FOUND: 3 LEFT: 3 TRANSFORMER CONNECTION: DELTA-WYE
WINDING TEMPERATURE: N/A °C LIQUID TEMPERATURE: 5 °C

TURNS RATIO TEST (TTR)

TEST PERFORMED AT: ______ V
SECONDARY VOLTAGE FOR RATIO CALCULATION: ______ V

TAP POSITION:	A	B	C	D	E
PRIMARY VOLTAGE:	28,980	28,290	27,600	26,910	26,220
CALCULATED RATIO:					
H1-H 2 ; X 0 X 2					
% RATIO DEVIATION:					
EXCITING CURRENT (m.a)					
H2-H 3 ; X 0 X 3					
% RATIO DEVIATION:					
EXCITING CURRENT (m.a)					
H3-H 1 ; X 0 X 1					
% RATIO DEVIATION:					
EXCITING CURRENT (m.a)					

INSULATION RESISTANCE (MEG-OHMS @ 1000VDC)

WINDING	HI TO LO & GND	LO TO HI & GND	HI & LO TO GND	CORE- GND
MEASURED	4170	27540	4130	N/A
CORRECTED TO 20C				

INSULATION CAPACITANCE AND DISSAPTION FACTOR

CONNECTION	CH-L + CH-G	CH-G	CH-L	CL-G	CL-H & CL-G
CAPACITANCE	4.701	7.066	9.992	6.931	6.768
MULTIPLIER	5000	500	2000	2000	5000
CAPACITANCE (p/f):	23505	3533	19984	13862	33840
CAPACITANCE CHECK:	23517	3533	19984	13862	33846
DISSIPATION	0.507	0.303	0.586	0.425	0.505
CORRECTED TO 20 C					

WINDING RESISTANCE ON AS LEFT TAP

HIGH VOLTAGE	H1-H2	H2-H3	H3-H1	H0-H1	H0-H2	H0-H3
Ohms	0.601	0.591	0.592	N/A	N/A	N/A
LOW VOLTAGE	X1-X2	X2-X3	X3-X1	X0-X1	X0-X2	X0-X3
Milli-Ohms	N/A	N/A	N/A	5.41	5.38	5.44

COMMENTS: Transformer oil temperature is outside of the correction curve limits.
Test results indicate that the transformer is in good condition at this time.

JOB NUMBER: JM0511354 TESTED BY: S. Maddeford/S. Urry DATE: January 25, 2006

Form 0001.R2

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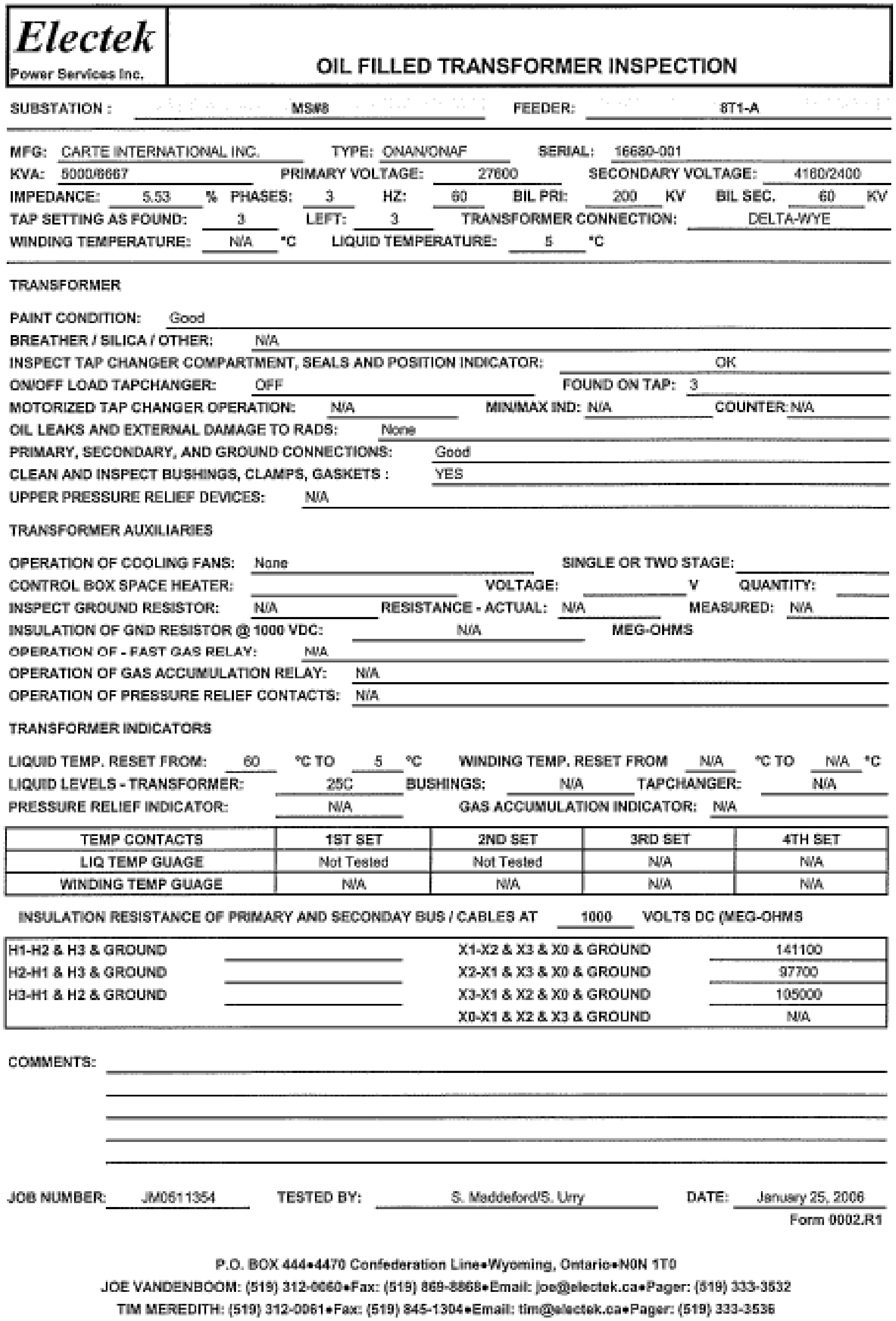

Electek
Power Services Inc.

OIL FILLED TRANSFORMER INSPECTION

SUBSTATION : MS#8 FEEDER: 8T1-A

MFG: CARTE INTERNATIONAL INC. TYPE: ONAN/ONAF SERIAL: 16680-001
KVA: 5000/6667 PRIMARY VOLTAGE: 27600 SECONDARY VOLTAGE: 4160/2400
IMPEDANCE: 5.53 % PHASES: 3 HZ: 60 BIL PRI: 200 KV BIL SEC. 60 KV
TAP SETTING AS FOUND: 3 LEFT: 3 TRANSFORMER CONNECTION: DELTA-WYE
WINDING TEMPERATURE: N/A °C LIQUID TEMPERATURE: 5 °C

TRANSFORMER

PAINT CONDITION: Good
BREATHER / SILICA / OTHER: N/A
INSPECT TAP CHANGER COMPARTMENT, SEALS AND POSITION INDICATOR: OK
ON/OFF LOAD TAPCHANGER: OFF FOUND ON TAP: 3
MOTORIZED TAP CHANGER OPERATION: N/A MIN/MAX IND: N/A COUNTER: N/A
OIL LEAKS AND EXTERNAL DAMAGE TO RADS: None
PRIMARY, SECONDARY, AND GROUND CONNECTIONS: Good
CLEAN AND INSPECT BUSHINGS, CLAMPS, GASKETS : YES
UPPER PRESSURE RELIEF DEVICES: N/A

TRANSFORMER AUXILIARIES

OPERATION OF COOLING FANS: None SINGLE OR TWO STAGE:
CONTROL BOX SPACE HEATER: VOLTAGE: V QUANTITY:
INSPECT GROUND RESISTOR: N/A RESISTANCE - ACTUAL: N/A MEASURED: N/A
INSULATION OF GND RESISTOR @ 1000 VDC: N/A MEG-OHMS
OPERATION OF - FAST GAS RELAY: N/A
OPERATION OF GAS ACCUMULATION RELAY: N/A
OPERATION OF PRESSURE RELIEF CONTACTS: N/A

TRANSFORMER INDICATORS

LIQUID TEMP. RESET FROM: 60 °C TO 5 °C WINDING TEMP. RESET FROM N/A °C TO N/A °C
LIQUID LEVELS - TRANSFORMER: 25C BUSHINGS: N/A TAPCHANGER: N/A
PRESSURE RELIEF INDICATOR: N/A GAS ACCUMULATION INDICATOR: N/A

TEMP CONTACTS	1ST SET	2ND SET	3RD SET	4TH SET
LIQ TEMP GUAGE	Not Tested	Not Tested	N/A	N/A
WINDING TEMP GUAGE	N/A	N/A	N/A	N/A

INSULATION RESISTANCE OF PRIMARY AND SECONDAY BUS / CABLES AT 1000 VOLTS DC (MEG-OHMS

H1-H2 & H3 & GROUND		X1-X2 & X3 & X0 & GROUND	141100
H2-H1 & H3 & GROUND		X2-X1 & X3 & X0 & GROUND	97700
H3-H1 & H2 & GROUND		X3-X1 & X2 & X0 & GROUND	105000
		X0-X1 & X2 & X3 & GROUND	N/A

COMMENTS:

JOB NUMBER: JM0611354 TESTED BY: S. Maddeford/S. Urry DATE: January 25, 2006

Form 0002.R1

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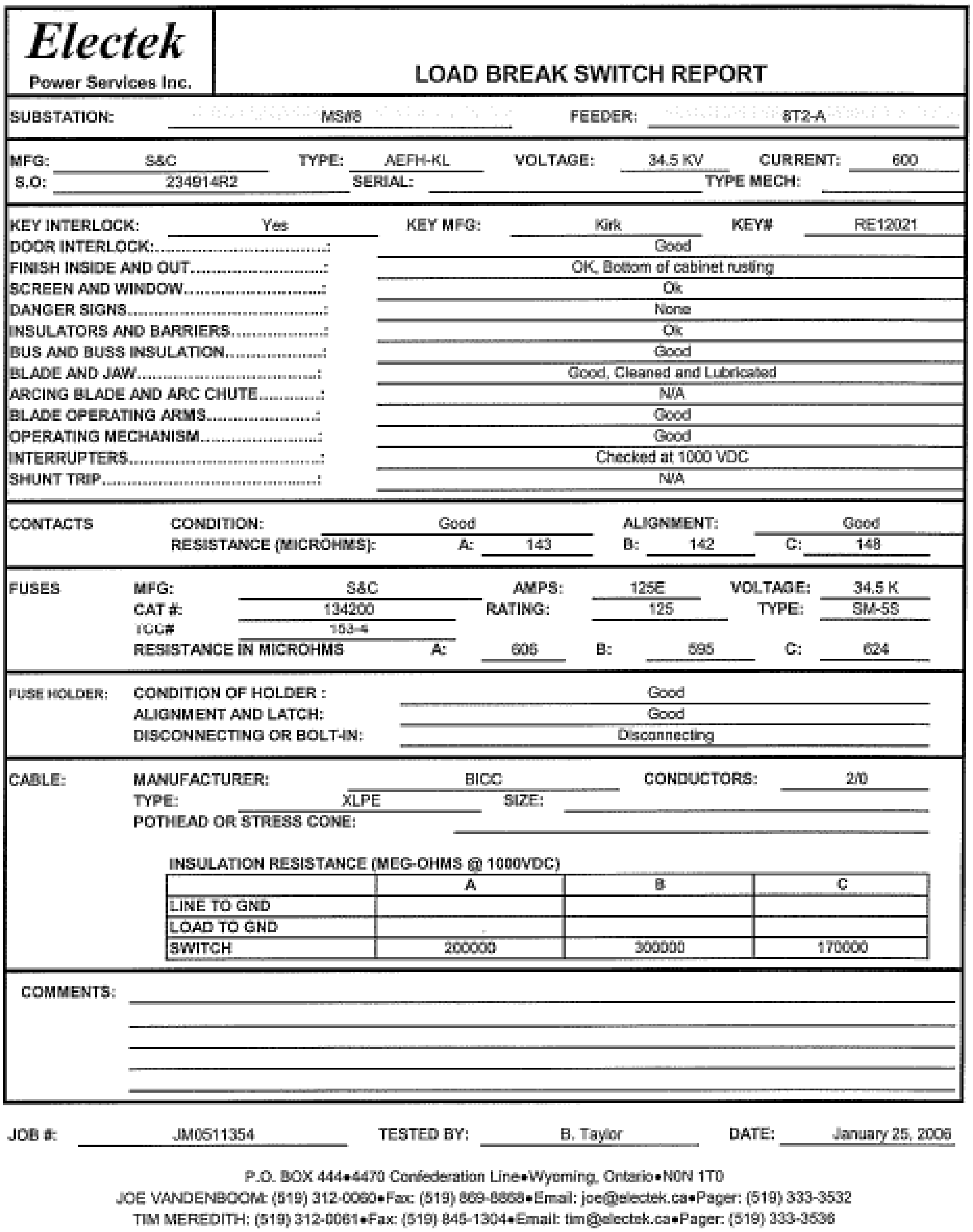

Electek
Power Services Inc.

LOAD BREAK SWITCH REPORT

SUBSTATION: MS#8 FEEDER: 8T2-A

MFG: S&C TYPE: AEFH-KL VOLTAGE: 34.5 KV CURRENT: 600
S.O: 234914R2 SERIAL: TYPE MECH:

KEY INTERLOCK: Yes KEY MFG: Kirk KEY# RE12021
DOOR INTERLOCK:..................................: Good
FINISH INSIDE AND OUT............................: OK, Bottom of cabinet rusting
SCREEN AND WINDOW............................: Ok
DANGER SIGNS.......................................: None
INSULATORS AND BARRIERS...................: Ok
BUS AND BUSS INSULATION...................: Good
BLADE AND JAW......................................: Good, Cleaned and Lubricated
ARCING BLADE AND ARC CHUTE............: N/A
BLADE OPERATING ARMS......................: Good
OPERATING MECHANISM........................: Good
INTERRUPTERS.......................................: Checked at 1000 VDC
SHUNT TRIP...: N/A

CONTACTS CONDITION: Good ALIGNMENT: Good
RESISTANCE (MICROHMS): A: 143 B: 142 C: 148

FUSES MFG: S&C AMPS: 125E VOLTAGE: 34.5 K
CAT #: 134200 RATING: 125 TYPE: SM-5S
TCC# 153-4
RESISTANCE IN MICROHMS A: 606 B: 595 C: 624

FUSE HOLDER: CONDITION OF HOLDER : Good
ALIGNMENT AND LATCH: Good
DISCONNECTING OR BOLT-IN: Disconnecting

CABLE: MANUFACTURER: BICC CONDUCTORS: 2/0
TYPE: XLPE SIZE:
POTHEAD OR STRESS CONE:

INSULATION RESISTANCE (MEG-OHMS @ 1000VDC)

	A	B	C
LINE TO GND			
LOAD TO GND			
SWITCH	200000	300000	170000

COMMENTS:

JOB #: JM0511354 TESTED BY: B. Taylor DATE: January 25, 2006

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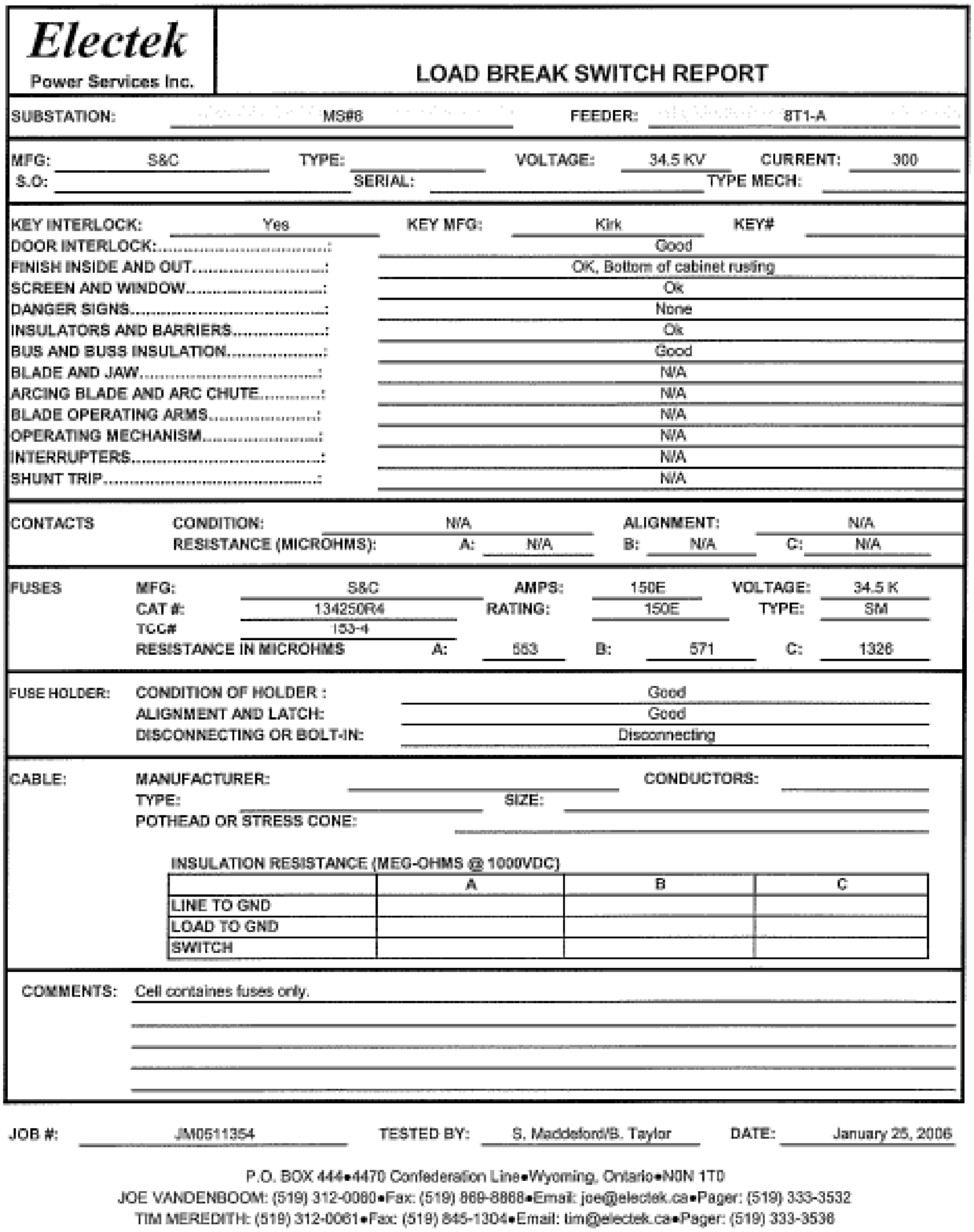

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LOAD BREAK SWITCH REPORT

SUBSTATION: MS#6 **FEEDER:** 8T1-A

MFG: S&C **TYPE:** **VOLTAGE:** 34.5 KV **CURRENT:** 300
S.O: **SERIAL:** **TYPE MECH:**

KEY INTERLOCK: Yes **KEY MFG:** Kirk **KEY#**
DOOR INTERLOCK:.................................: Good
FINISH INSIDE AND OUT............................: OK, Bottom of cabinet rusting
SCREEN AND WINDOW...........................: Ok
DANGER SIGNS.......................................: None
INSULATORS AND BARRIERS...................: Ok
BUS AND BUSS INSULATION...................: Good
BLADE AND JAW....................................: N/A
ARCING BLADE AND ARC CHUTE............: N/A
BLADE OPERATING ARMS......................: N/A
OPERATING MECHANISM........................: N/A
INTERRUPTERS......................................: N/A
SHUNT TRIP..: N/A

CONTACTS **CONDITION:** N/A **ALIGNMENT:** N/A
RESISTANCE (MICROHMS): A: N/A B: N/A C: N/A

FUSES **MFG:** S&C **AMPS:** 150E **VOLTAGE:** 34.5 K
CAT #: 134250R4 **RATING:** 150E **TYPE:** SM
TCC# 153-4
RESISTANCE IN MICROHMS A: 553 B: 571 C: 1326

FUSE HOLDER: **CONDITION OF HOLDER :** Good
ALIGNMENT AND LATCH: Good
DISCONNECTING OR BOLT-IN: Disconnecting

CABLE: **MANUFACTURER:** **CONDUCTORS:**
TYPE: **SIZE:**
POTHEAD OR STRESS CONE:

INSULATION RESISTANCE (MEG-OHMS @ 1000VDC)

	A	B	C
LINE TO GND			
LOAD TO GND			
SWITCH			

COMMENTS: Cell containes fuses only.

JOB #: JM0511354 **TESTED BY:** S. Maddeford/B. Taylor **DATE:** January 25, 2006

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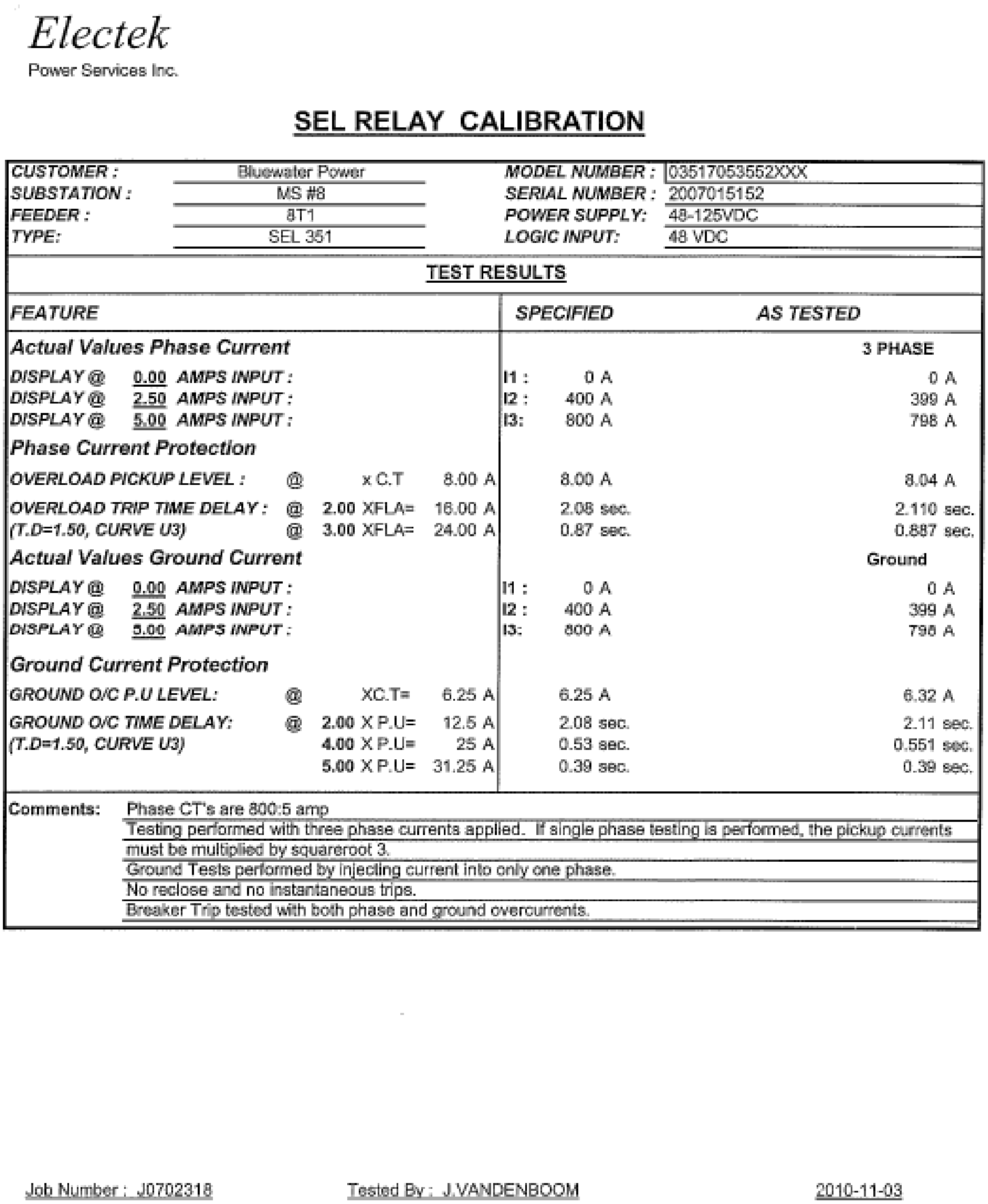

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SEL RELAY CALIBRATION

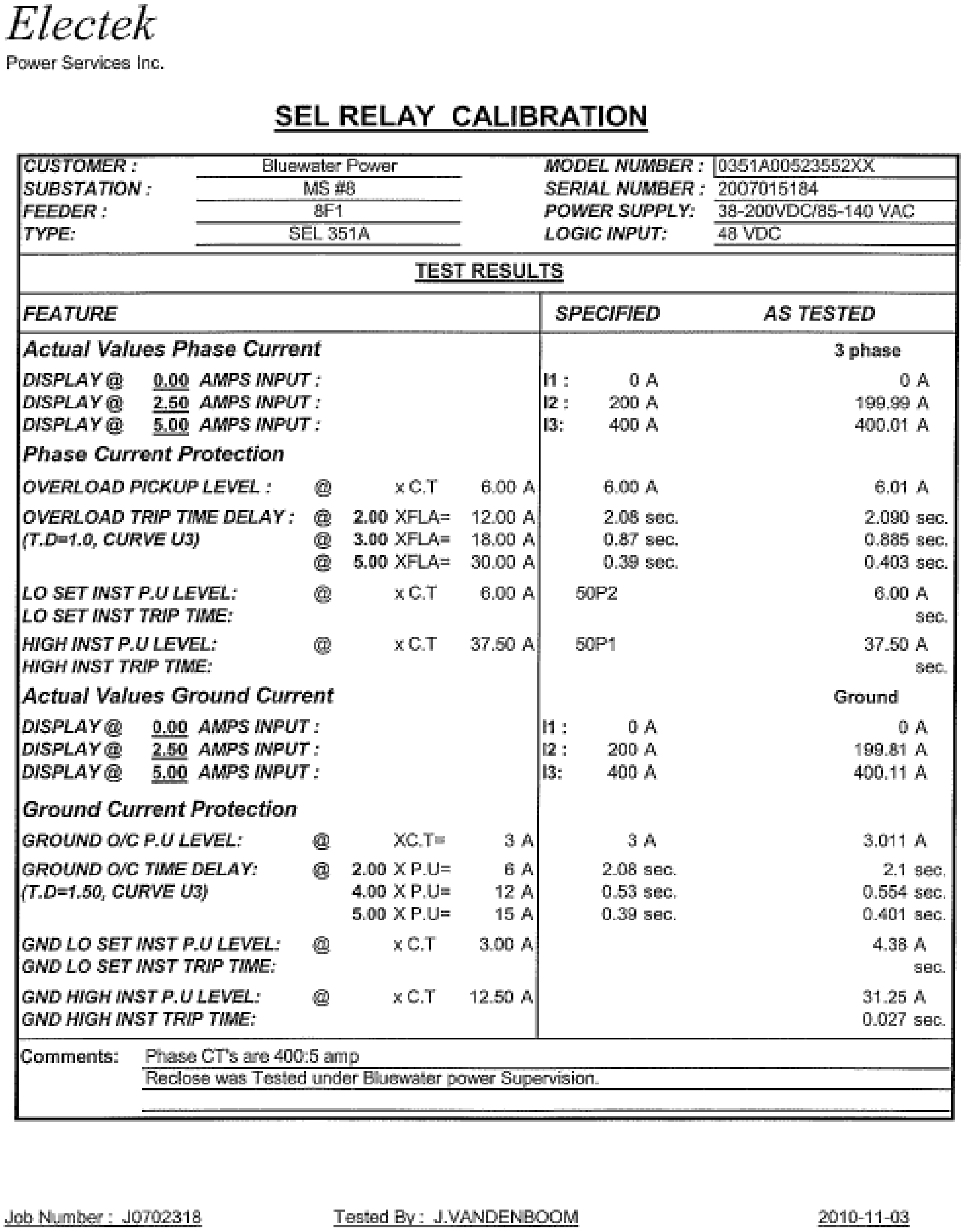
CUSTOMER :	Bluewater Power	*MODEL NUMBER :*	03517053552XXX
SUBSTATION :	MS #8	*SERIAL NUMBER :*	2007015152
FEEDER :	8T1	*POWER SUPPLY:*	48-125VDC
TYPE:	SEL 351	*LOGIC INPUT:*	48 VDC

TEST RESULTS

FEATURE				*SPECIFIED*		*AS TESTED*
Actual Values Phase Current						**3 PHASE**
DISPLAY @ 0.00 AMPS INPUT :				I1 :	0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 :	400 A	399 A
DISPLAY @ 5.00 AMPS INPUT :				I3:	800 A	798 A
Phase Current Protection						
OVERLOAD PICKUP LEVEL :	@	x C.T	8.00 A		8.00 A	8.04 A
OVERLOAD TRIP TIME DELAY :	@	**2.00** XFLA=	16.00 A		2.08 sec.	2.110 sec.
(T.D=1.50, CURVE U3)	@	**3.00** XFLA=	24.00 A		0.87 sec.	0.887 sec.
Actual Values Ground Current						**Ground**
DISPLAY @ 0.00 AMPS INPUT :				I1 :	0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 :	400 A	399 A
DISPLAY @ 5.00 AMPS INPUT :				I3:	800 A	798 A
Ground Current Protection						
GROUND O/C P.U LEVEL:	@	XC.T=	6.25 A		6.25 A	6.32 A
GROUND O/C TIME DELAY:	@	**2.00** X P.U=	12.5 A		2.08 sec.	2.11 sec.
(T.D=1.50, CURVE U3)		**4.00** X P.U=	25 A		0.53 sec.	0.551 sec.
		5.00 X P.U=	31.25 A		0.39 sec.	0.39 sec.

Comments: Phase CT's are 800:5 amp
Testing performed with three phase currents applied. If single phase testing is performed, the pickup currents must be multiplied by squareroot 3.
Ground Tests performed by injecting current into only one phase.
No reclose and no instantaneous trips.
Breaker Trip tested with both phase and ground overcurrents.

Job Number : J0702318 Tested By : J.VANDENBOOM 2010-11-03



Electek
Power Services Inc.

SEL RELAY CALIBRATION

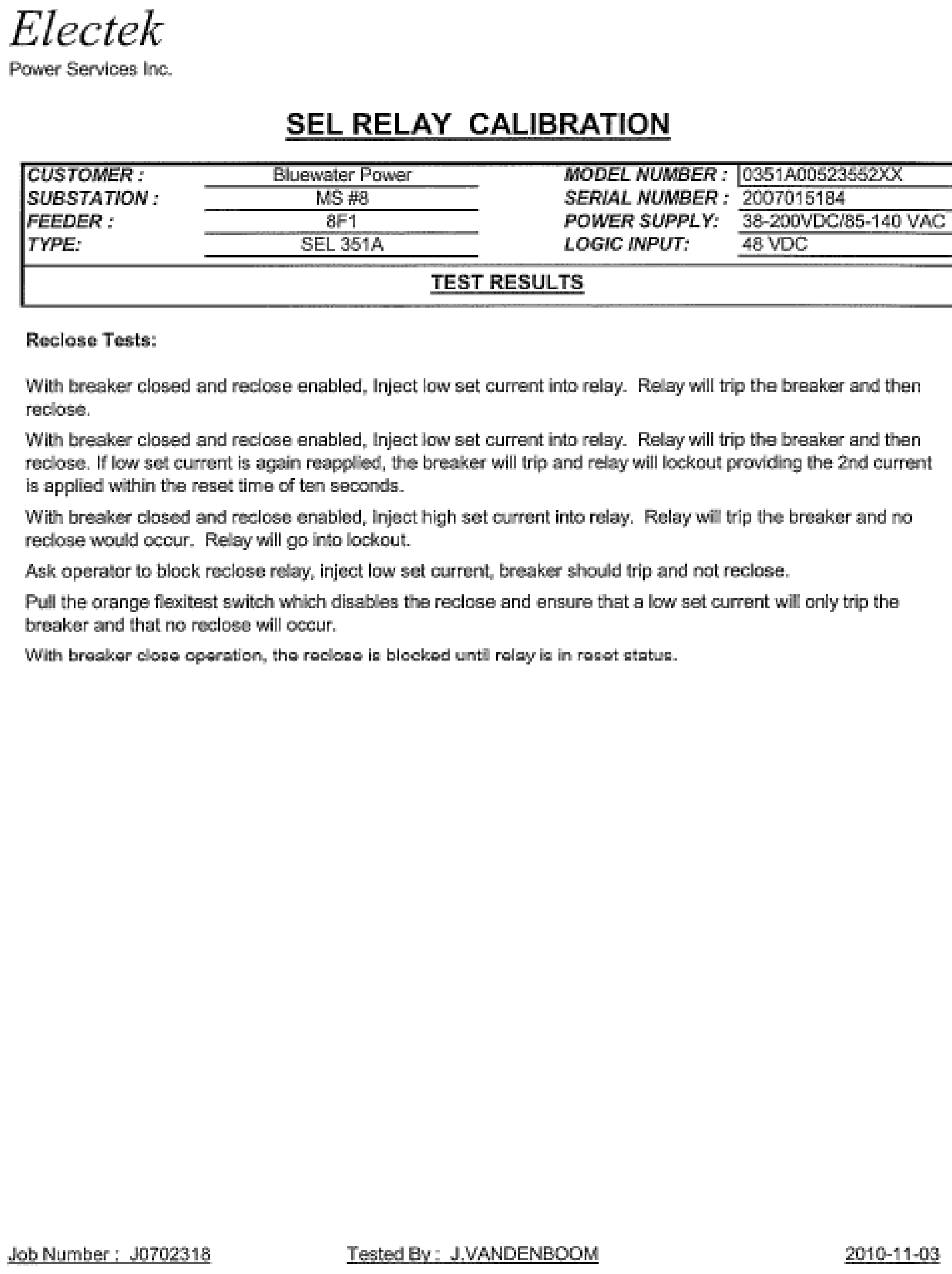
CUSTOMER :	Bluewater Power	*MODEL NUMBER :*	0351A00523552XX
SUBSTATION :	MS #8	*SERIAL NUMBER :*	2007015184
FEEDER :	8F1	*POWER SUPPLY:*	38-200VDC/85-140 VAC
TYPE:	SEL 351A	*LOGIC INPUT:*	48 VDC

TEST RESULTS

FEATURE				*SPECIFIED*	*AS TESTED*
Actual Values Phase Current					**3 phase**
DISPLAY @ 0.00 AMPS INPUT :				I1 : 0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 : 200 A	199.99 A
DISPLAY @ 5.00 AMPS INPUT :				I3: 400 A	400.01 A
Phase Current Protection					
OVERLOAD PICKUP LEVEL :	@	x C.T	6.00 A	6.00 A	6.01 A
OVERLOAD TRIP TIME DELAY :	@	**2.00** XFLA=	12.00 A	2.08 sec.	2.090 sec.
(T.D=1.0, CURVE U3)	@	**3.00** XFLA=	18.00 A	0.87 sec.	0.885 sec.
	@	**5.00** XFLA=	30.00 A	0.39 sec.	0.403 sec.
LO SET INST P.U LEVEL:	@	x C.T	6.00 A	50P2	6.00 A
LO SET INST TRIP TIME:					sec.
HIGH INST P.U LEVEL:	@	x C.T	37.50 A	50P1	37.50 A
HIGH INST TRIP TIME:					sec.
Actual Values Ground Current					**Ground**
DISPLAY @ 0.00 AMPS INPUT :				I1 : 0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 : 200 A	199.81 A
DISPLAY @ 5.00 AMPS INPUT :				I3: 400 A	400.11 A
Ground Current Protection					
GROUND O/C P.U LEVEL:	@	XC.T=	3 A	3 A	3.011 A
GROUND O/C TIME DELAY:	@	**2.00** X P.U=	6 A	2.08 sec.	2.1 sec.
(T.D=1.50, CURVE U3)		**4.00** X P.U=	12 A	0.53 sec.	0.554 sec.
		5.00 X P.U=	15 A	0.39 sec.	0.401 sec.
GND LO SET INST P.U LEVEL:	@	x C.T	3.00 A		4.38 A
GND LO SET INST TRIP TIME:					sec.
GND HIGH INST P.U LEVEL:	@	x C.T	12.50 A		31.25 A
GND HIGH INST TRIP TIME:					0.027 sec.

Comments: Phase CT's are 400:5 amp
Reclose was Tested under Bluewater power Supervision.

Job Number : J0702318
Tested By : J.VANDENBOOM
2010-11-03



Electek
Power Services Inc.

SEL RELAY CALIBRATION

CUSTOMER :	Bluewater Power	***MODEL NUMBER :***	0351A00523552XX
SUBSTATION :	MS #8	***SERIAL NUMBER :***	2007015184
FEEDER :	8F1	***POWER SUPPLY:***	38-200VDC/85-140 VAC
TYPE:	SEL 351A	***LOGIC INPUT:***	48 VDC

TEST RESULTS

Reclose Tests:

With breaker closed and reclose enabled, Inject low set current into relay. Relay will trip the breaker and then reclose.

With breaker closed and reclose enabled, Inject low set current into relay. Relay will trip the breaker and then reclose. If low set current is again reapplied, the breaker will trip and relay will lockout providing the 2nd current is applied within the reset time of ten seconds.

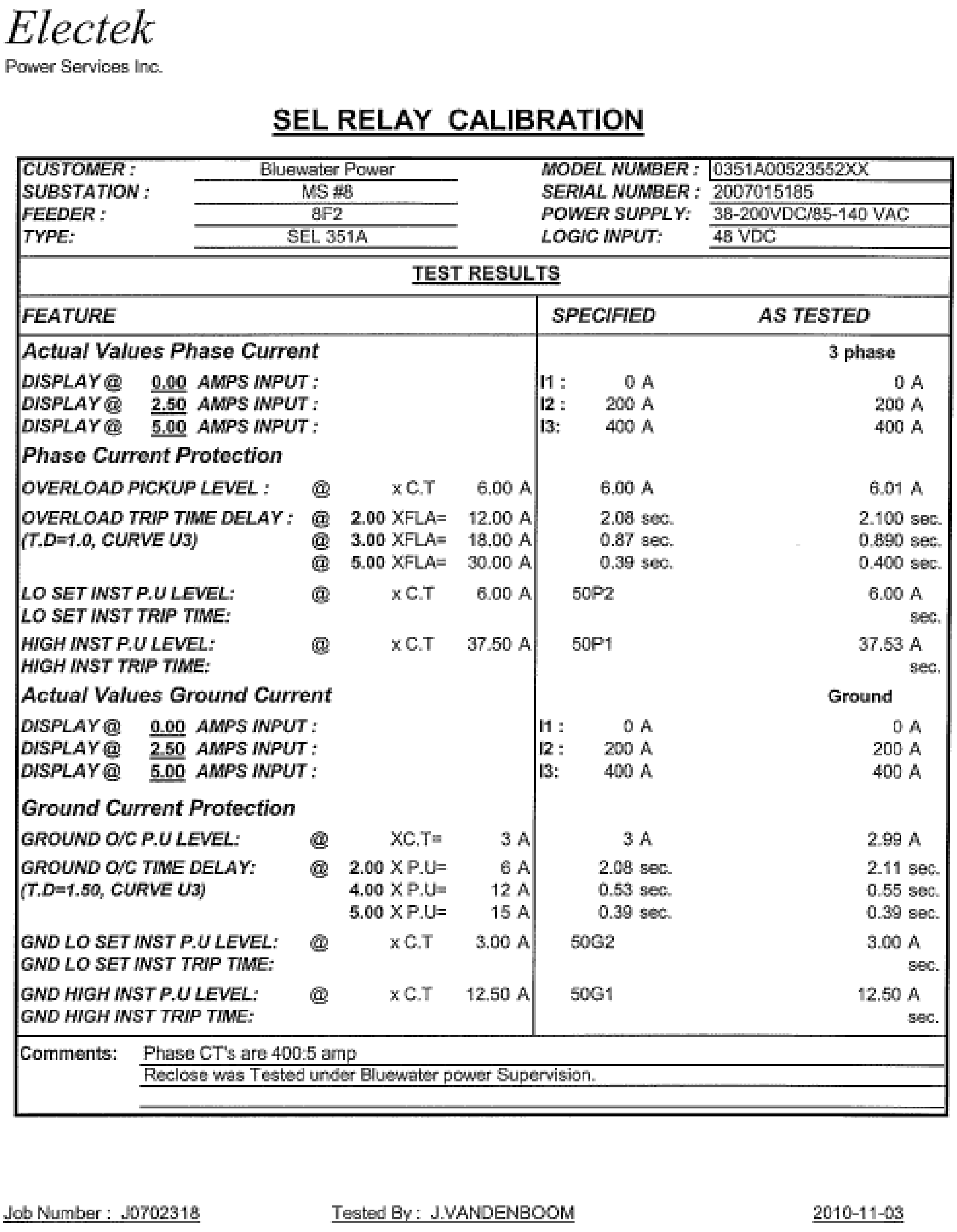
With breaker closed and reclose enabled, Inject high set current into relay. Relay will trip the breaker and no reclose would occur. Relay will go into lockout.

Ask operator to block reclose relay, inject low set current, breaker should trip and not reclose.

Pull the orange flexitest switch which disables the reclose and ensure that a low set current will only trip the breaker and that no reclose will occur.

With breaker close operation, the reclose is blocked until relay is in reset status.

Job Number : J0702318 Tested By : J.VANDENBOOM 2010-11-03



Electek
Power Services Inc.

SEL RELAY CALIBRATION

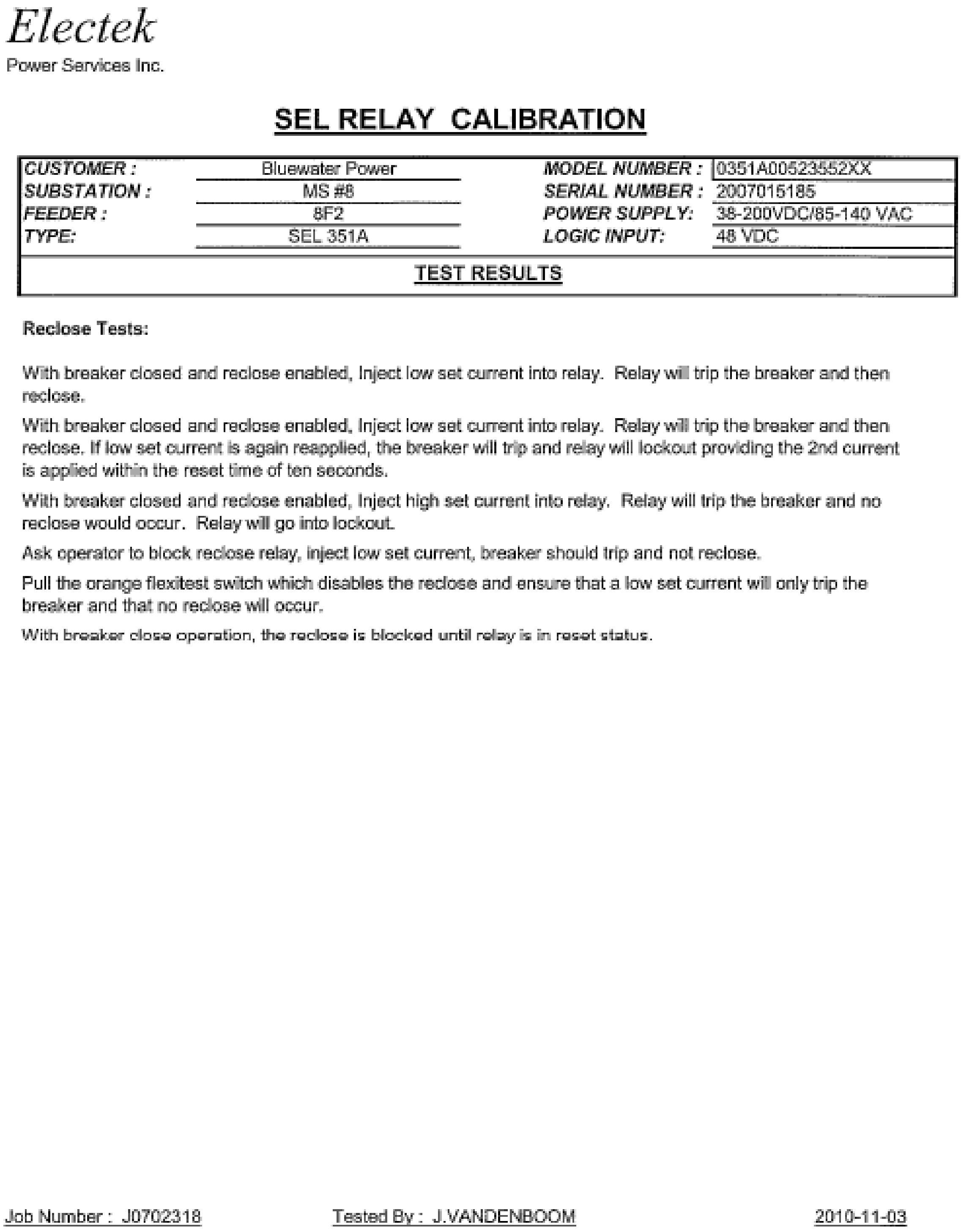
CUSTOMER :	Bluewater Power	*MODEL NUMBER :*	0351A00523552XX
SUBSTATION :	MS #8	*SERIAL NUMBER :*	2007015185
FEEDER :	8F2	*POWER SUPPLY:*	38-200VDC/85-140 VAC
TYPE:	SEL 351A	*LOGIC INPUT:*	48 VDC

TEST RESULTS

FEATURE				*SPECIFIED*		*AS TESTED*
Actual Values Phase Current						**3 phase**
DISPLAY @ 0.00 AMPS INPUT :				I1 :	0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 :	200 A	200 A
DISPLAY @ 5.00 AMPS INPUT :				I3:	400 A	400 A
Phase Current Protection						
OVERLOAD PICKUP LEVEL :	@	x C.T	6.00 A		6.00 A	6.01 A
OVERLOAD TRIP TIME DELAY :	@	**2.00** XFLA=	12.00 A		2.08 sec.	2.100 sec.
(T.D=1.0, CURVE U3)	@	**3.00** XFLA=	18.00 A		0.87 sec.	0.890 sec.
	@	**5.00** XFLA=	30.00 A		0.39 sec.	0.400 sec.
LO SET INST P.U LEVEL:	@	x C.T	6.00 A	50P2		6.00 A
LO SET INST TRIP TIME:						sec.
HIGH INST P.U LEVEL:	@	x C.T	37.50 A	50P1		37.53 A
HIGH INST TRIP TIME:						sec.
Actual Values Ground Current						**Ground**
DISPLAY @ 0.00 AMPS INPUT :				I1 :	0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 :	200 A	200 A
DISPLAY @ 5.00 AMPS INPUT :				I3:	400 A	400 A
Ground Current Protection						
GROUND O/C P.U LEVEL:	@	XC.T=	3 A		3 A	2.99 A
GROUND O/C TIME DELAY:	@	**2.00** X P.U=	6 A		2.08 sec.	2.11 sec.
(T.D=1.50, CURVE U3)		**4.00** X P.U=	12 A		0.53 sec.	0.55 sec.
		5.00 X P.U=	15 A		0.39 sec.	0.39 sec.
GND LO SET INST P.U LEVEL:	@	x C.T	3.00 A	50G2		3.00 A
GND LO SET INST TRIP TIME:						sec.
GND HIGH INST P.U LEVEL:	@	x C.T	12.50 A	50G1		12.50 A
GND HIGH INST TRIP TIME:						sec.

Comments: Phase CT's are 400:5 amp
Reclose was Tested under Bluewater power Supervision.

Job Number : J0702318 Tested By : J.VANDENBOOM 2010-11-03



Electek
Power Services Inc.

SEL RELAY CALIBRATION

CUSTOMER :	Bluewater Power	***MODEL NUMBER :***	0351A00523552XX
SUBSTATION :	MS #8	***SERIAL NUMBER :***	2007015185
FEEDER :	8F2	***POWER SUPPLY:***	38-200VDC/85-140 VAC
TYPE:	SEL 351A	***LOGIC INPUT:***	48 VDC

TEST RESULTS

Reclose Tests:

With breaker closed and reclose enabled, Inject low set current into relay. Relay will trip the breaker and then reclose.

With breaker closed and reclose enabled, Inject low set current into relay. Relay will trip the breaker and then reclose. If low set current is again reapplied, the breaker will trip and relay will lockout providing the 2nd current is applied within the reset time of ten seconds.

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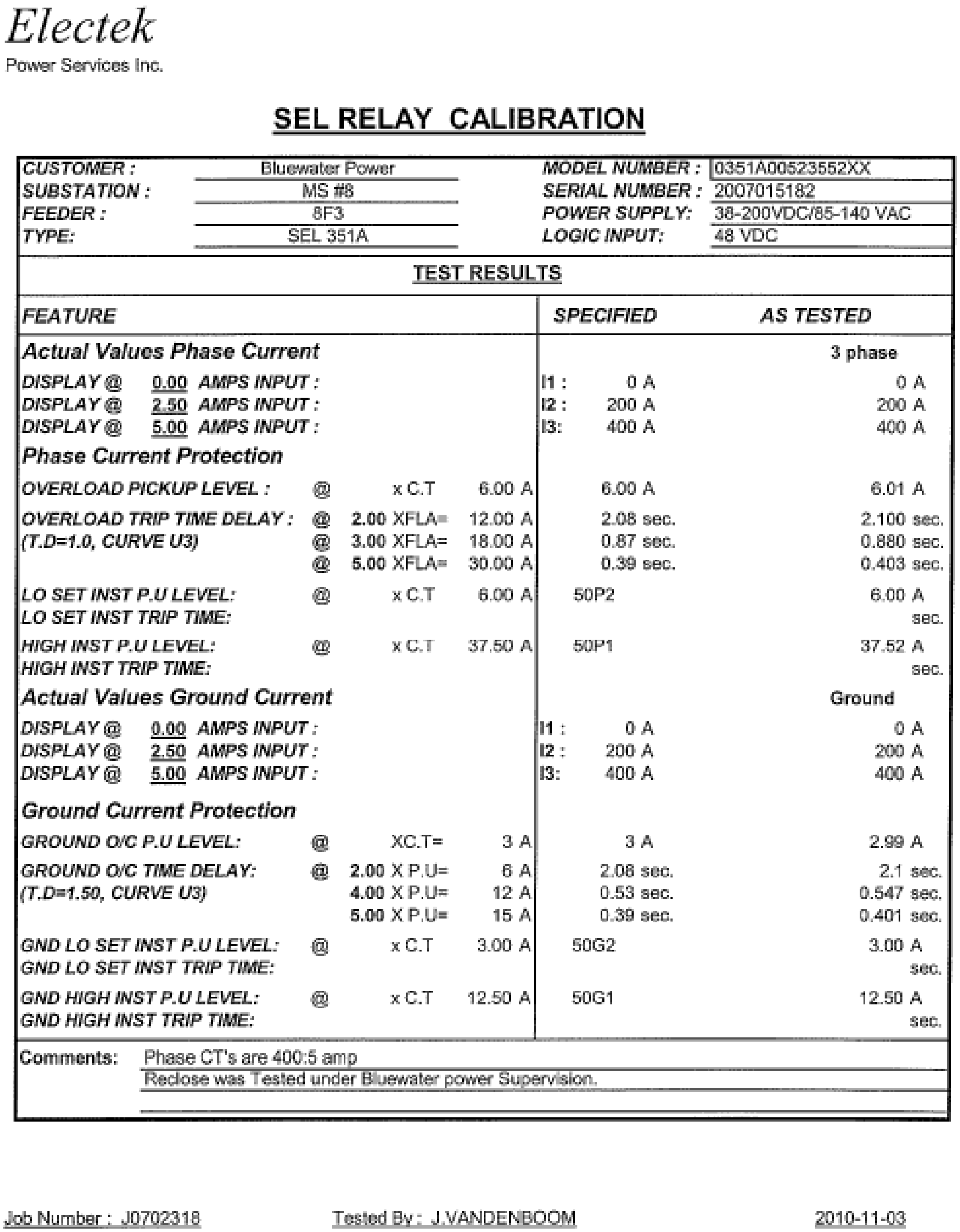
With breaker close operation, the reclose is blocked until relay is in reset status.

Job Number : J0702318   Tested By : J.VANDENBOOM   2010-11-03



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SEL RELAY CALIBRATION

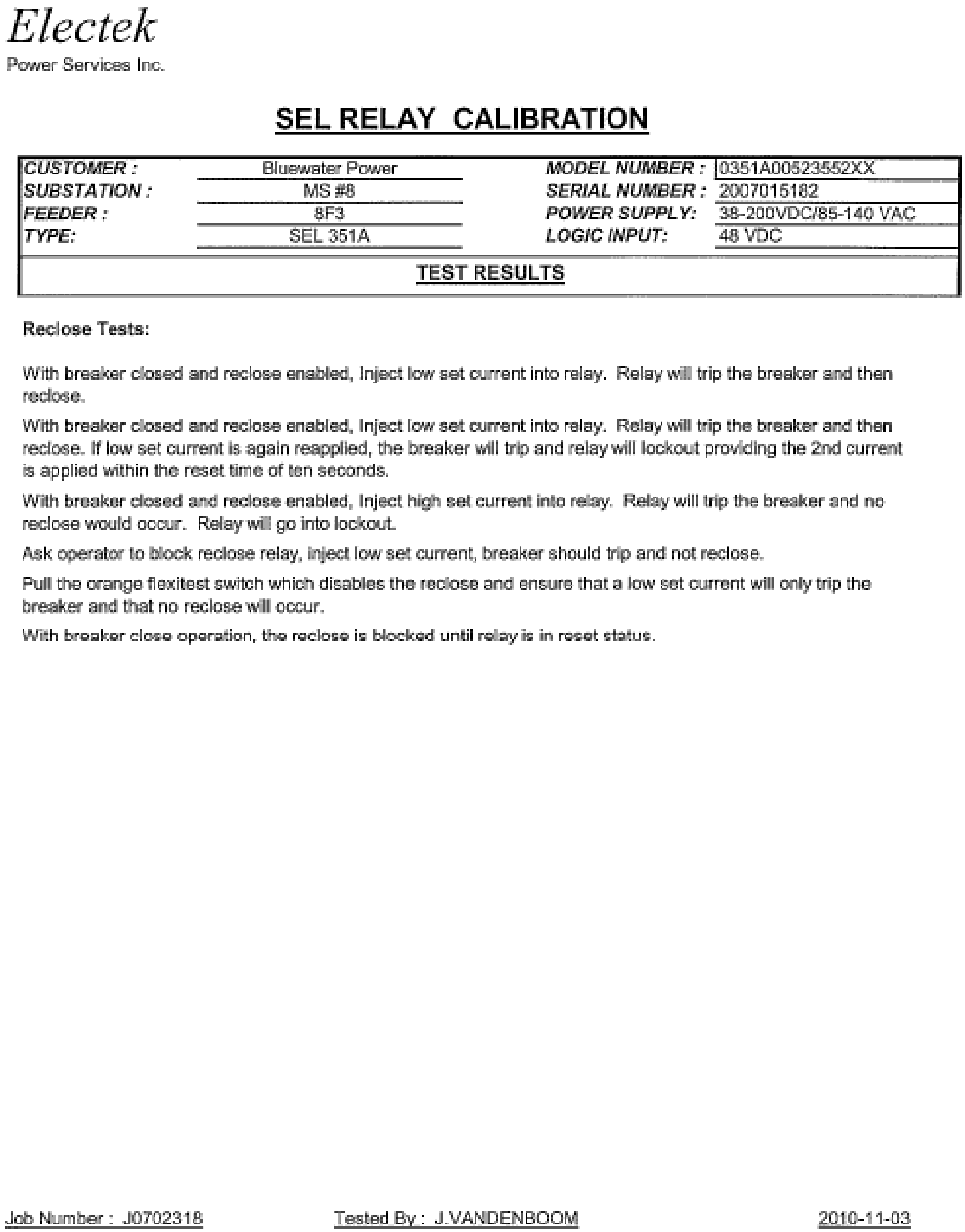
CUSTOMER :	Bluewater Power	**MODEL NUMBER :**	0351A00523552XX
SUBSTATION :	MS #8	**SERIAL NUMBER :**	2007015182
FEEDER :	8F3	**POWER SUPPLY:**	38-200VDC/85-140 VAC
TYPE:	SEL 351A	**LOGIC INPUT:**	48 VDC

TEST RESULTS

FEATURE				SPECIFIED	AS TESTED
Actual Values Phase Current					3 phase
DISPLAY @ 0.00 AMPS INPUT :				I1 : 0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 : 200 A	200 A
DISPLAY @ 5.00 AMPS INPUT :				I3: 400 A	400 A
Phase Current Protection					
OVERLOAD PICKUP LEVEL :	@	x C.T	6.00 A	6.00 A	6.01 A
OVERLOAD TRIP TIME DELAY :	@	2.00 XFLA=	12.00 A	2.08 sec.	2.100 sec.
(T.D=1.0, CURVE U3)	@	3.00 XFLA=	18.00 A	0.87 sec.	0.880 sec.
	@	5.00 XFLA=	30.00 A	0.39 sec.	0.403 sec.
LO SET INST P.U LEVEL:	@	x C.T	6.00 A	50P2	6.00 A
LO SET INST TRIP TIME:					sec.
HIGH INST P.U LEVEL:	@	x C.T	37.50 A	50P1	37.52 A
HIGH INST TRIP TIME:					sec.
Actual Values Ground Current					Ground
DISPLAY @ 0.00 AMPS INPUT :				I1 : 0 A	0 A
DISPLAY @ 2.50 AMPS INPUT :				I2 : 200 A	200 A
DISPLAY @ 5.00 AMPS INPUT :				I3: 400 A	400 A
Ground Current Protection					
GROUND O/C P.U LEVEL:	@	XC.T=	3 A	3 A	2.99 A
GROUND O/C TIME DELAY:	@	2.00 X P.U=	6 A	2.08 sec.	2.1 sec.
(T.D=1.50, CURVE U3)		4.00 X P.U=	12 A	0.53 sec.	0.547 sec.
		5.00 X P.U=	15 A	0.39 sec.	0.401 sec.
GND LO SET INST P.U LEVEL:	@	x C.T	3.00 A	50G2	3.00 A
GND LO SET INST TRIP TIME:					sec.
GND HIGH INST P.U LEVEL:	@	x C.T	12.50 A	50G1	12.50 A
GND HIGH INST TRIP TIME:					sec.

Comments: Phase CT's are 400:5 amp
Reclose was Tested under Bluewater power Supervision.

Job Number : J0702318 Tested By : J.VANDENBOOM 2010-11-03



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SEL RELAY CALIBRATION

CUSTOMER :	Bluewater Power	***MODEL NUMBER :***	0351A00523552XX
SUBSTATION :	MS #8	***SERIAL NUMBER :***	2007015182
FEEDER :	8F3	***POWER SUPPLY:***	38-200VDC/85-140 VAC
TYPE:	SEL 351A	***LOGIC INPUT:***	48 VDC

TEST RESULTS

Reclose Tests:

With breaker closed and reclose enabled, Inject low set current into relay. Relay will trip the breaker and then reclose.

With breaker closed and reclose enabled, Inject low set current into relay. Relay will trip the breaker and then reclose. If low set current is again reapplied, the breaker will trip and relay will lockout providing the 2nd current is applied within the reset time of ten seconds.

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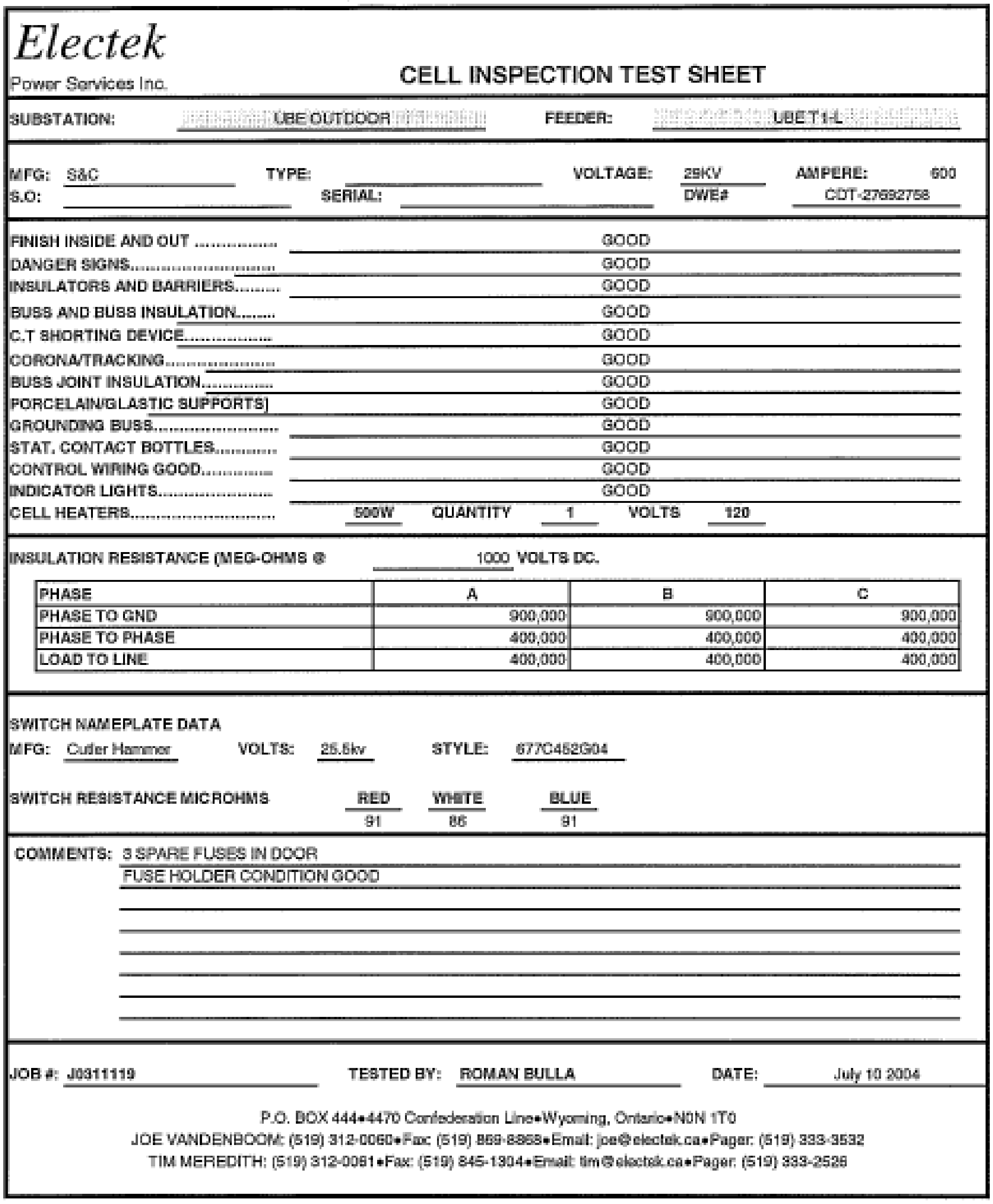
Job Number : J0702318 Tested By : J.VANDENBOOM 2010-11-03



Electek
Power Services Inc.

CELL INSPECTION TEST SHEET

SUBSTATION: UBE OUTDOOR **FEEDER:** UBE T1-L

MFG: S&C **TYPE:** **VOLTAGE:** 29KV **AMPERE:** 600
S.O: **SERIAL:** **DWE#** CDT-27692758

FINISH INSIDE AND OUT	GOOD
DANGER SIGNS............................	GOOD
INSULATORS AND BARRIERS.........	GOOD
BUSS AND BUSS INSULATION........	GOOD
C.T SHORTING DEVICE.................	GOOD
CORONA/TRACKING.....................	GOOD
BUSS JOINT INSULATION..............	GOOD
PORCELAIN/GLASTIC SUPPORTS)	GOOD
GROUNDING BUSS........................	GOOD
STAT. CONTACT BOTTLES............	GOOD
CONTROL WIRING GOOD.............	GOOD
INDICATOR LIGHTS......................	GOOD

CELL HEATERS............................ 500W **QUANTITY** 1 **VOLTS** 120

INSULATION RESISTANCE (MEG-OHMS @ 1000 **VOLTS DC.**

PHASE	A	B	C
PHASE TO GND	900,000	900,000	900,000
PHASE TO PHASE	400,000	400,000	400,000
LOAD TO LINE	400,000	400,000	400,000

SWITCH NAMEPLATE DATA
MFG: Cutler Hammer **VOLTS:** 25.5kv **STYLE:** 677C452G04

SWITCH RESISTANCE MICROHMS	RED	WHITE	BLUE
	91	86	91

COMMENTS: 3 SPARE FUSES IN DOOR
FUSE HOLDER CONDITION GOOD

JOB #: J0311119 **TESTED BY:** ROMAN BULLA **DATE:** July 10 2004

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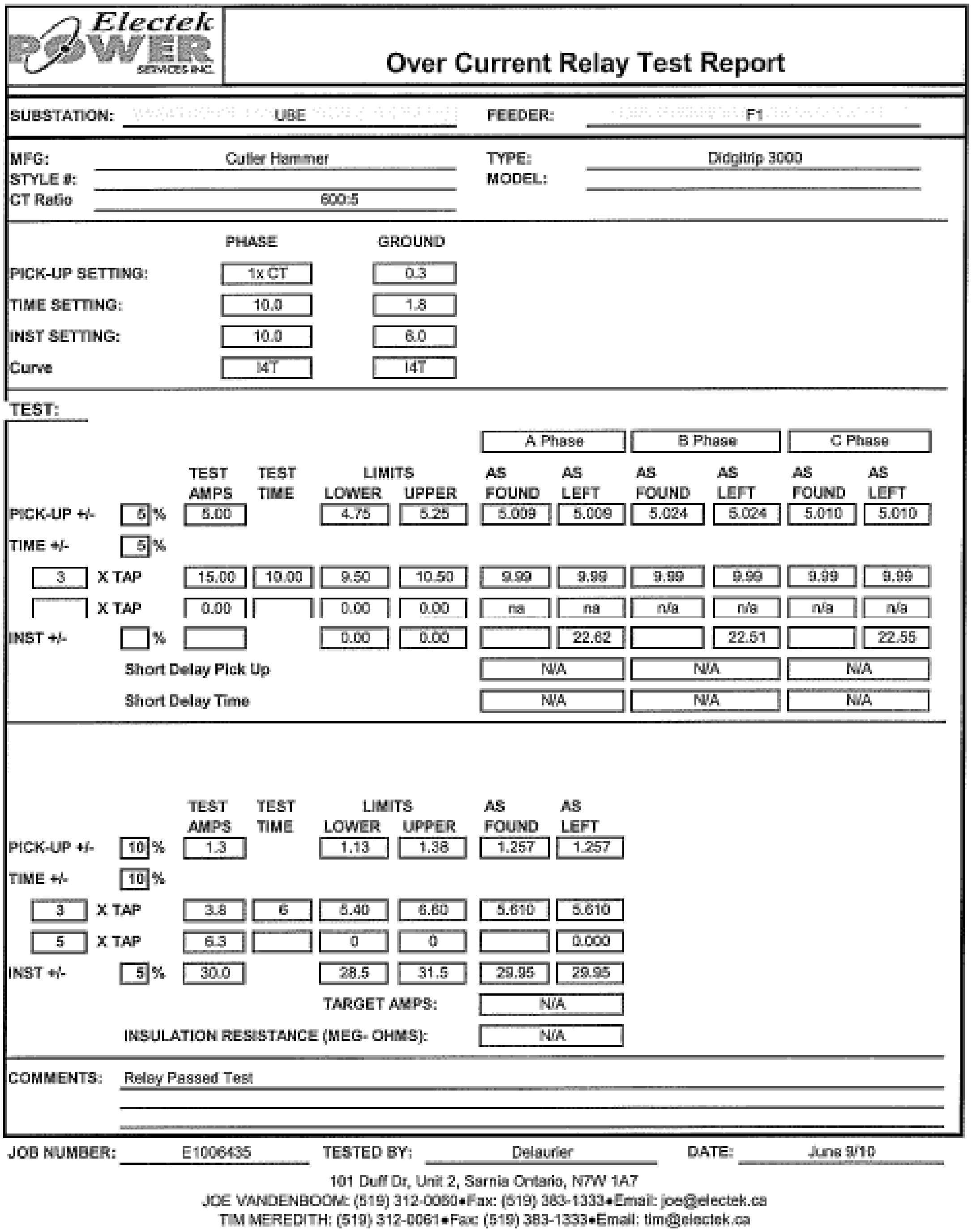
TIM MEREDITH: (519) 312-0061•Fax: (519) 845-1304•Email: tim@electek.ca•Pager: (519) 333-2528



Electek POWER SERVICES INC.

Over Current Relay Test Report

SUBSTATION: UBE **FEEDER:** F1

MFG: Cutler Hammer **TYPE:** Didgitrip 3000
STYLE #: **MODEL:**
CT Ratio 600:5

	PHASE	GROUND
PICK-UP SETTING:	1x CT	0.3
TIME SETTING:	10.0	1.8
INST SETTING:	10.0	6.0
Curve	I4T	I4T

TEST:

						A Phase		B Phase		C Phase	
		TEST AMPS	TEST TIME	LIMITS LOWER	UPPER	AS FOUND	AS LEFT	AS FOUND	AS LEFT	AS FOUND	AS LEFT
PICK-UP +/-	5 %	5.00		4.75	5.25	5.009	5.009	5.024	5.024	5.010	5.010
TIME +/-	5 %										
3 X TAP		15.00	10.00	9.50	10.50	9.99	9.99	9.99	9.99	9.99	9.99
X TAP		0.00		0.00	0.00	na	na	n/a	n/a	n/a	n/a
INST +/-	%			0.00	0.00		22.62		22.51		22.55
Short Delay Pick Up						N/A		N/A		N/A	
Short Delay Time						N/A		N/A		N/A	

		TEST AMPS	TEST TIME	LIMITS LOWER	UPPER	AS FOUND	AS LEFT
PICK-UP +/-	10 %	1.3		1.13	1.38	1.257	1.257
TIME +/-	10 %						
3 X TAP		3.8	6	5.40	6.60	5.610	5.610
5 X TAP		6.3		0	0		0.000
INST +/-	5 %	30.0		28.5	31.5	29.95	29.95

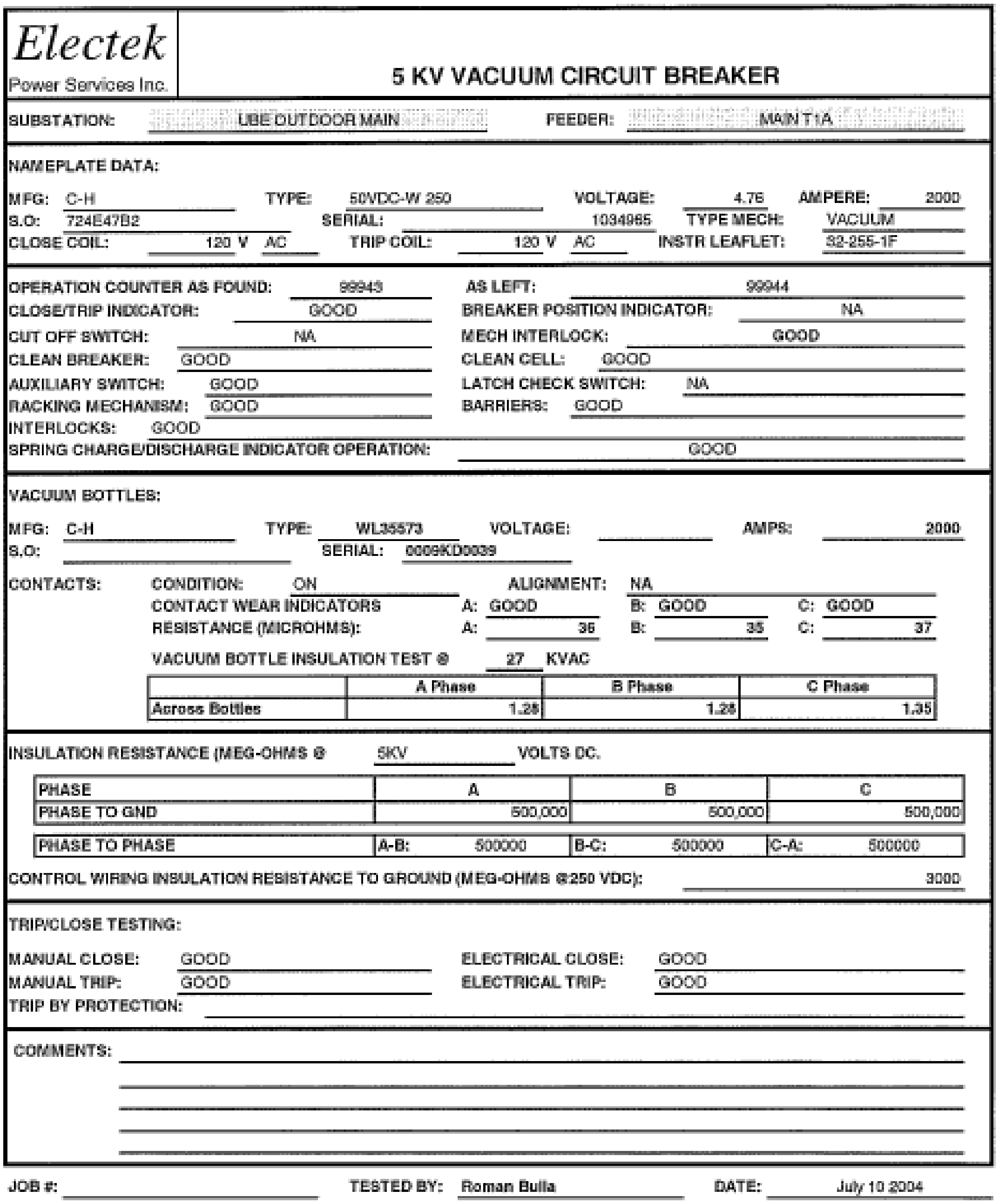
TARGET AMPS: N/A

INSULATION RESISTANCE (MEG- OHMS): N/A

COMMENTS: Relay Passed Test

JOB NUMBER: E1006435 **TESTED BY:** Delaurier **DATE:** June 9/10

101 Duff Dr, Unit 2, Sarnia Ontario, N7W 1A7
JOE VANDENBOOM: (519) 312-0060•Fax: (519) 383-1333•Email: joe@electek.ca
TIM MEREDITH: (519) 312-0061•Fax: (519) 383-1333•Email: tim@electek.ca



Electek
Power Services Inc.

5 KV VACUUM CIRCUIT BREAKER

SUBSTATION: UBE OUTDOOR MAIN **FEEDER:** MAIN T1A

NAMEPLATE DATA:

MFG: C-H **TYPE:** 50VDC-W 250 **VOLTAGE:** 4.76 **AMPERE:** 2000
S.O: 724E47B2 **SERIAL:** 1034965 **TYPE MECH:** VACUUM
CLOSE COIL: 120 V AC **TRIP COIL:** 120 V AC **INSTR LEAFLET:** 32-255-1F

OPERATION COUNTER AS FOUND: 99943 **AS LEFT:** 99944
CLOSE/TRIP INDICATOR: GOOD **BREAKER POSITION INDICATOR:** NA
CUT OFF SWITCH: NA **MECH INTERLOCK:** GOOD
CLEAN BREAKER: GOOD **CLEAN CELL:** GOOD
AUXILIARY SWITCH: GOOD **LATCH CHECK SWITCH:** NA
RACKING MECHANISM: GOOD **BARRIERS:** GOOD
INTERLOCKS: GOOD
SPRING CHARGE/DISCHARGE INDICATOR OPERATION: GOOD

VACUUM BOTTLES:

MFG: C-H **TYPE:** WL35573 **VOLTAGE:** **AMPS:** 2000
S.O: **SERIAL:** 0009KD0039

CONTACTS: **CONDITION:** ON **ALIGNMENT:** NA
CONTACT WEAR INDICATORS A: GOOD B: GOOD C: GOOD
RESISTANCE (MICROHMS): A: 36 B: 35 C: 37

VACUUM BOTTLE INSULATION TEST @ 27 **KVAC**

	A Phase	B Phase	C Phase
Across Bottles	1.28	1.28	1.35

INSULATION RESISTANCE (MEG-OHMS @ 5KV **VOLTS DC.**

PHASE	A	B	C
PHASE TO GND	500,000	500,000	500,000
PHASE TO PHASE	A-B: 500000	B-C: 500000	C-A: 500000

CONTROL WIRING INSULATION RESISTANCE TO GROUND (MEG-OHMS @250 VDC): 3000

TRIP/CLOSE TESTING:

MANUAL CLOSE: GOOD **ELECTRICAL CLOSE:** GOOD
MANUAL TRIP: GOOD **ELECTRICAL TRIP:** GOOD
TRIP BY PROTECTION:

COMMENTS:

JOB #: **TESTED BY:** Roman Bulla **DATE:** July 10 2004

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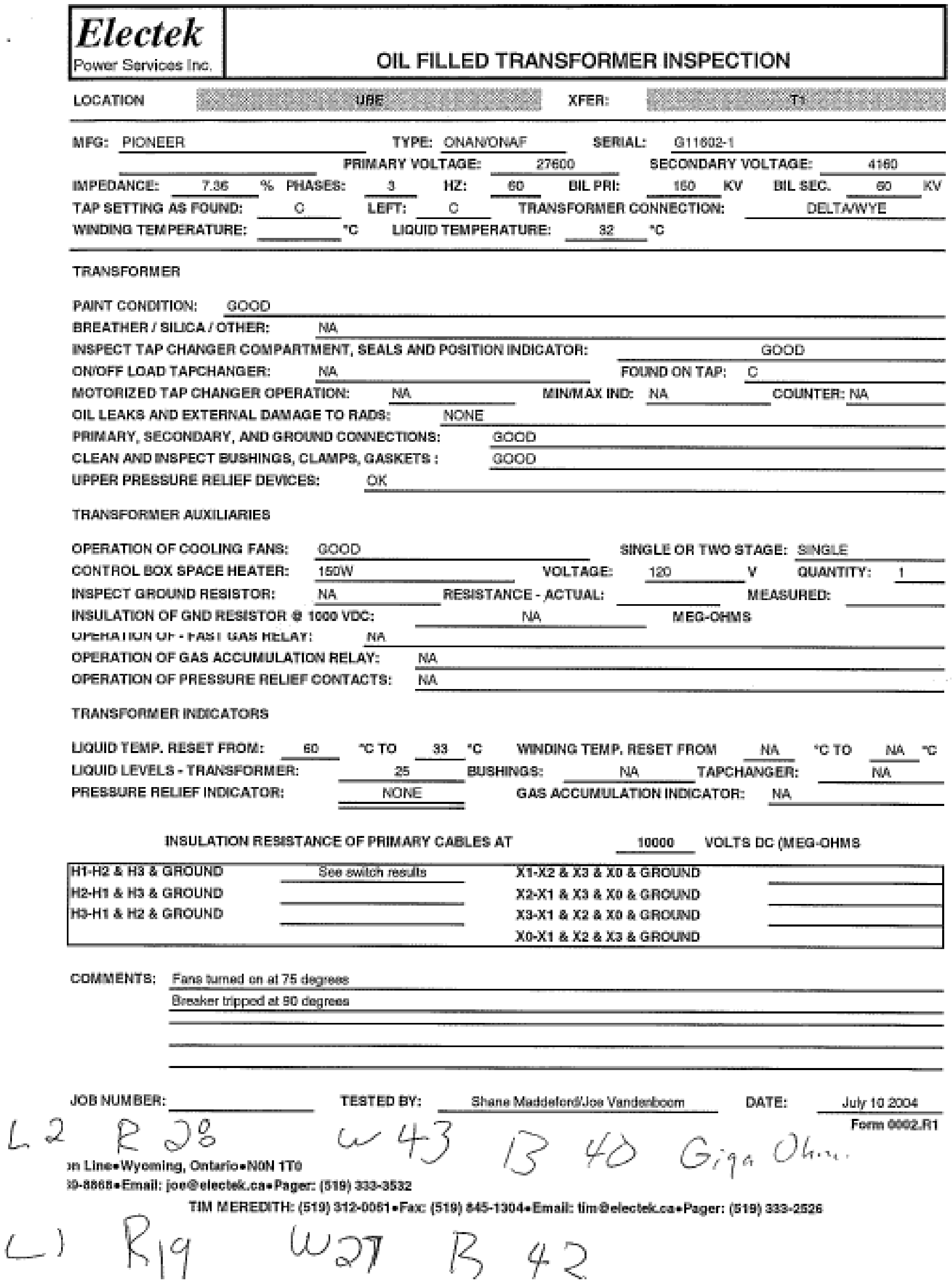

Electek
Power Services Inc.

OIL FILLED TRANSFORMER INSPECTION

LOCATION: UBE XFER: T1

MFG: PIONEER TYPE: ONAN/ONAF SERIAL: G11602-1
PRIMARY VOLTAGE: 27600 SECONDARY VOLTAGE: 4160
IMPEDANCE: 7.36 % PHASES: 3 HZ: 60 BIL PRI: 150 KV BIL SEC. 60 KV
TAP SETTING AS FOUND: C LEFT: C TRANSFORMER CONNECTION: DELTA/WYE
WINDING TEMPERATURE: ____ °C LIQUID TEMPERATURE: 32 °C

TRANSFORMER

PAINT CONDITION: GOOD
BREATHER / SILICA / OTHER: NA
INSPECT TAP CHANGER COMPARTMENT, SEALS AND POSITION INDICATOR: GOOD
ON/OFF LOAD TAPCHANGER: NA FOUND ON TAP: C
MOTORIZED TAP CHANGER OPERATION: NA MIN/MAX IND: NA COUNTER: NA
OIL LEAKS AND EXTERNAL DAMAGE TO RADS: NONE
PRIMARY, SECONDARY, AND GROUND CONNECTIONS: GOOD
CLEAN AND INSPECT BUSHINGS, CLAMPS, GASKETS : GOOD
UPPER PRESSURE RELIEF DEVICES: OK

TRANSFORMER AUXILIARIES

OPERATION OF COOLING FANS: GOOD SINGLE OR TWO STAGE: SINGLE
CONTROL BOX SPACE HEATER: 150W VOLTAGE: 120 V QUANTITY: 1
INSPECT GROUND RESISTOR: NA RESISTANCE - ACTUAL: ____ MEASURED: ____
INSULATION OF GND RESISTOR @ 1000 VDC: NA MEG-OHMS
OPERATION OF - FAST GAS RELAY: NA
OPERATION OF GAS ACCUMULATION RELAY: NA
OPERATION OF PRESSURE RELIEF CONTACTS: NA

TRANSFORMER INDICATORS

LIQUID TEMP. RESET FROM: 60 °C TO 33 °C WINDING TEMP. RESET FROM NA °C TO NA °C
LIQUID LEVELS - TRANSFORMER: 25 BUSHINGS: NA TAPCHANGER: NA
PRESSURE RELIEF INDICATOR: NONE GAS ACCUMULATION INDICATOR: NA

INSULATION RESISTANCE OF PRIMARY CABLES AT 10000 VOLTS DC (MEG-OHMS

H1-H2 & H3 & GROUND	See switch results	X1-X2 & X3 & X0 & GROUND	
H2-H1 & H3 & GROUND		X2-X1 & X3 & X0 & GROUND	
H3-H1 & H2 & GROUND		X3-X1 & X2 & X0 & GROUND	
		X0-X1 & X2 & X3 & GROUND	

COMMENTS: Fans turned on at 75 degrees
Breaker tripped at 90 degrees

JOB NUMBER: ____ TESTED BY: Shane Maddeford/Joe Vandenboom DATE: July 10 2004
Form 0002.R1

L2 R 28 w 43 B 40 Giga Ohm

on Line•Wyoming, Ontario•N0N 1T0
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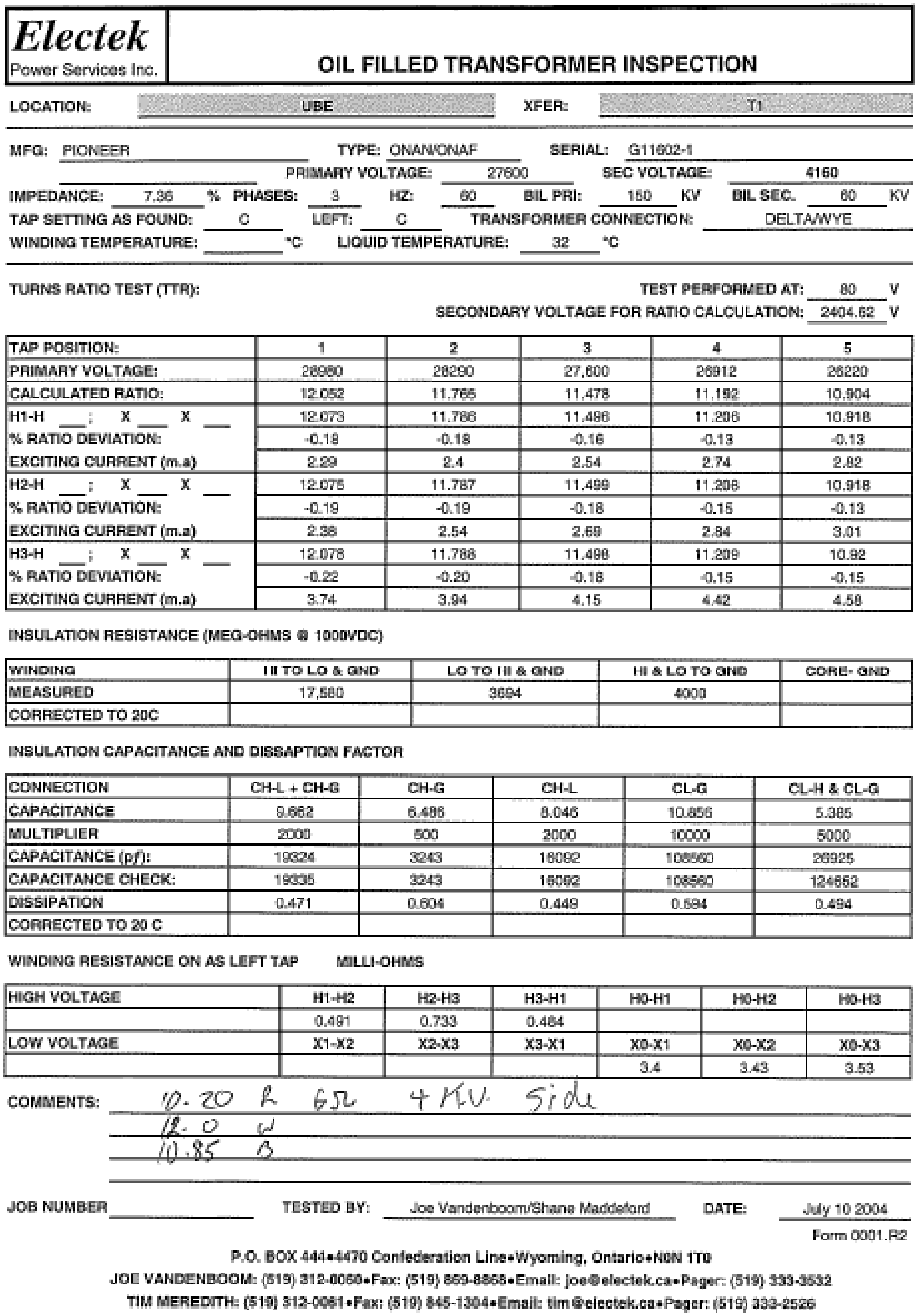
L1 R19 W27 B 42



Electek
Power Services Inc.

OIL FILLED TRANSFORMER INSPECTION

LOCATION: UBE XFER: T1

MFG: PIONEER TYPE: ONAN/ONAF SERIAL: G11602-1
PRIMARY VOLTAGE: 27600 SEC VOLTAGE: 4160
IMPEDANCE: 7.36 % PHASES: 3 HZ: 60 BIL PRI: 150 KV BIL SEC. 60 KV
TAP SETTING AS FOUND: C LEFT: C TRANSFORMER CONNECTION: DELTA/WYE
WINDING TEMPERATURE: ____ °C LIQUID TEMPERATURE: 32 °C

TURNS RATIO TEST (TTR):
TEST PERFORMED AT: 80 V
SECONDARY VOLTAGE FOR RATIO CALCULATION: 2404.62 V

TAP POSITION:	1	2	3	4	5
PRIMARY VOLTAGE:	28980	28290	27,600	26912	26220
CALCULATED RATIO:	12.052	11.766	11.478	11.192	10.904
H1-H ___; X ___ X ___	12.073	11.786	11.496	11.206	10.918
% RATIO DEVIATION:	-0.18	-0.18	-0.16	-0.13	-0.13
EXCITING CURRENT (m.a)	2.29	2.4	2.54	2.74	2.82
H2-H ___; X ___ X ___	12.075	11.787	11.499	11.208	10.918
% RATIO DEVIATION:	-0.19	-0.19	-0.18	-0.15	-0.13
EXCITING CURRENT (m.a)	2.38	2.54	2.69	2.84	3.01
H3-H ___; X ___ X ___	12.078	11.788	11.498	11.209	10.92
% RATIO DEVIATION:	-0.22	-0.20	-0.18	-0.15	-0.15
EXCITING CURRENT (m.a)	3.74	3.94	4.15	4.42	4.58

INSULATION RESISTANCE (MEG-OHMS @ 1000VDC)

WINDING	HI TO LO & GND	LO TO HI & GND	HI & LO TO GND	CORE- GND
MEASURED	17,580	3694	4000	
CORRECTED TO 20C				

INSULATION CAPACITANCE AND DISSAPTION FACTOR

CONNECTION	CH-L + CH-G	CH-G	CH-L	CL-G	CL-H & CL-G
CAPACITANCE	9.662	6.486	8.046	10.856	5.385
MULTIPLIER	2000	500	2000	10000	5000
CAPACITANCE (pf):	19324	3243	16092	108560	26925
CAPACITANCE CHECK:	19335	3243	16092	108560	124652
DISSIPATION	0.471	0.604	0.449	0.594	0.494
CORRECTED TO 20 C					

WINDING RESISTANCE ON AS LEFT TAP MILLI-OHMS

HIGH VOLTAGE	H1-H2	H2-H3	H3-H1	H0-H1	H0-H2	H0-H3
	0.491	0.733	0.484			
LOW VOLTAGE	X1-X2	X2-X3	X3-X1	X0-X1	X0-X2	X0-X3
				3.4	3.43	3.53

COMMENTS: 10.20 R 6Ω 4KV Side
12.0 W
10.85 B

JOB NUMBER ____ TESTED BY: Joe Vandenboom/Shane Maddeford DATE: July 10 2004

Form 0001.R2

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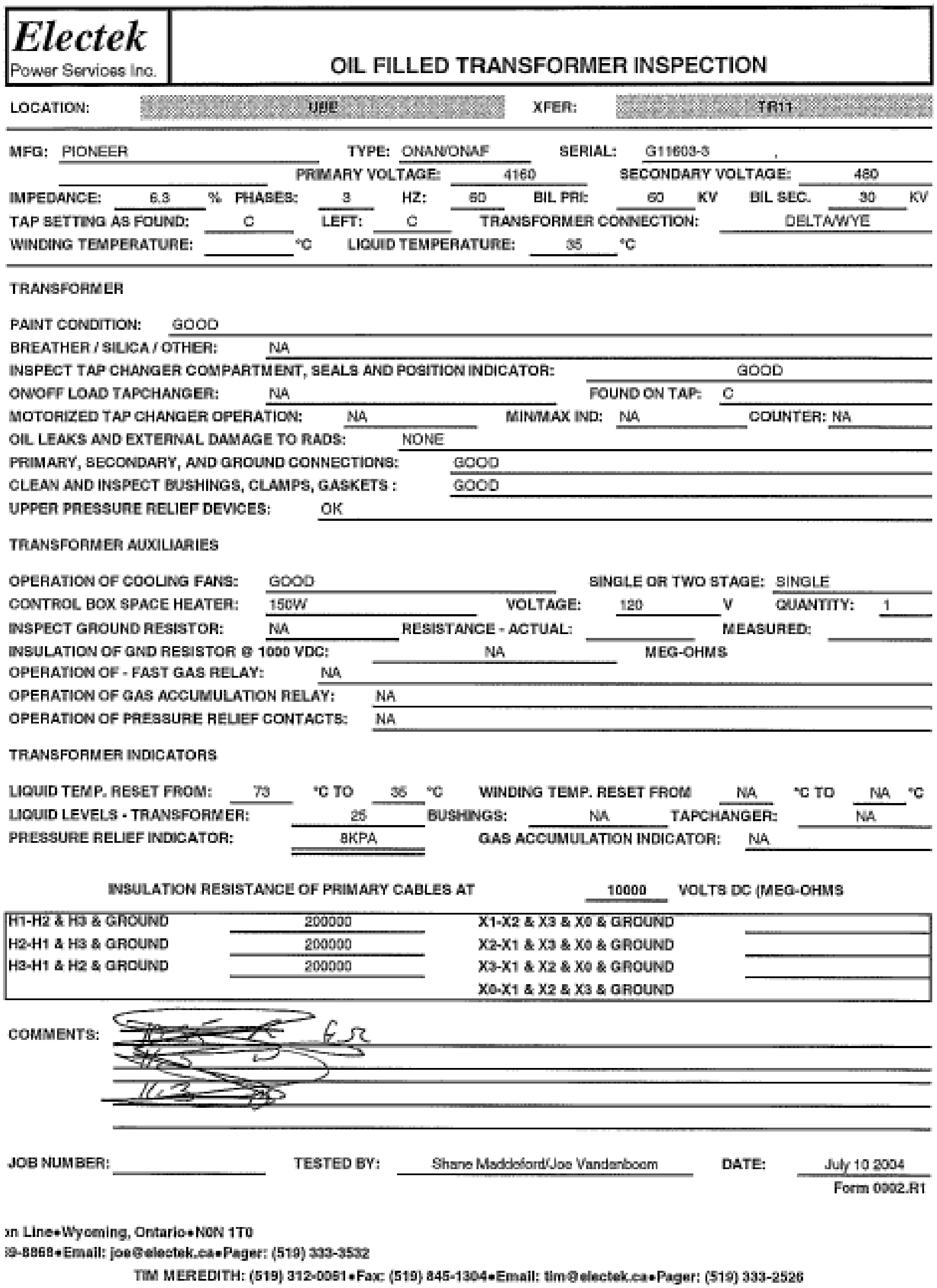


Electek
Power Services Inc.

OIL FILLED TRANSFORMER INSPECTION

LOCATION: UBE XFER: TR11

MFG: PIONEER TYPE: ONAN/ONAF SERIAL: G11603-3 ,
PRIMARY VOLTAGE: 4160 SECONDARY VOLTAGE: 480
IMPEDANCE: 6.3 % PHASES: 3 HZ: 60 BIL PRI: 60 KV BIL SEC. 30 KV
TAP SETTING AS FOUND: C LEFT: C TRANSFORMER CONNECTION: DELTA/WYE
WINDING TEMPERATURE: °C LIQUID TEMPERATURE: 35 °C

TRANSFORMER

PAINT CONDITION: GOOD
BREATHER / SILICA / OTHER: NA
INSPECT TAP CHANGER COMPARTMENT, SEALS AND POSITION INDICATOR: GOOD
ON/OFF LOAD TAPCHANGER: NA FOUND ON TAP: C
MOTORIZED TAP CHANGER OPERATION: NA MIN/MAX IND: NA COUNTER: NA
OIL LEAKS AND EXTERNAL DAMAGE TO RADS: NONE
PRIMARY, SECONDARY, AND GROUND CONNECTIONS: GOOD
CLEAN AND INSPECT BUSHINGS, CLAMPS, GASKETS : GOOD
UPPER PRESSURE RELIEF DEVICES: OK

TRANSFORMER AUXILIARIES

OPERATION OF COOLING FANS: GOOD SINGLE OR TWO STAGE: SINGLE
CONTROL BOX SPACE HEATER: 150W VOLTAGE: 120 V QUANTITY: 1
INSPECT GROUND RESISTOR: NA RESISTANCE - ACTUAL: MEASURED:
INSULATION OF GND RESISTOR @ 1000 VDC: NA MEG-OHMS
OPERATION OF - FAST GAS RELAY: NA
OPERATION OF GAS ACCUMULATION RELAY: NA
OPERATION OF PRESSURE RELIEF CONTACTS: NA

TRANSFORMER INDICATORS

LIQUID TEMP. RESET FROM: 73 °C TO 35 °C WINDING TEMP. RESET FROM NA °C TO NA °C
LIQUID LEVELS - TRANSFORMER: 25 BUSHINGS: NA TAPCHANGER: NA
PRESSURE RELIEF INDICATOR: 8KPA GAS ACCUMULATION INDICATOR: NA

INSULATION RESISTANCE OF PRIMARY CABLES AT 10000 VOLTS DC (MEG-OHMS

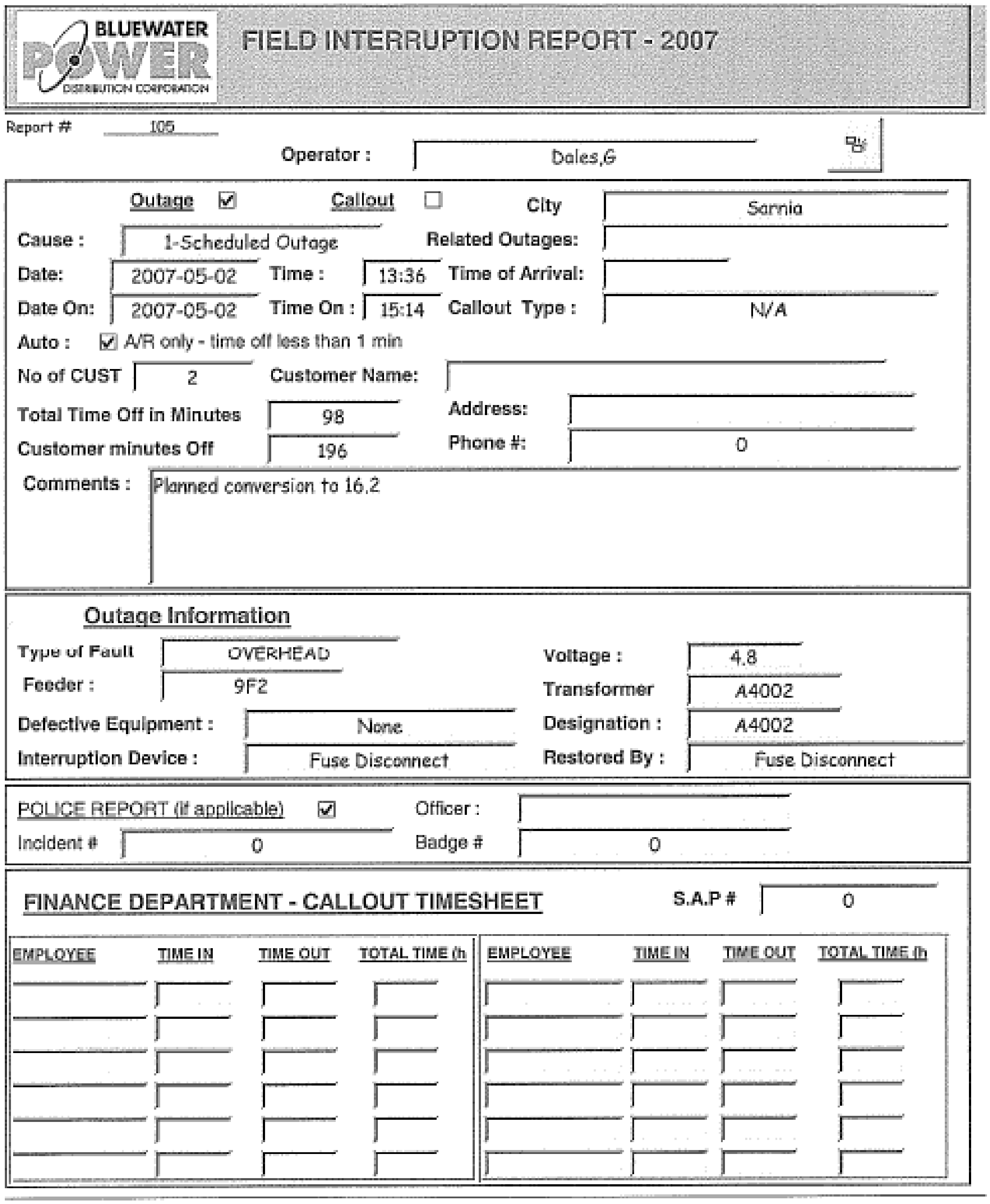
H1-H2 & H3 & GROUND	200000	X1-X2 & X3 & X0 & GROUND	
H2-H1 & H3 & GROUND	200000	X2-X1 & X3 & X0 & GROUND	
H3-H1 & H2 & GROUND	200000	X3-X1 & X2 & X0 & GROUND	
		X0-X1 & X2 & X3 & GROUND	

COMMENTS: [redacted]

JOB NUMBER: TESTED BY: Shane Maddeford/Joe Vandenboom DATE: July 10 2004
Form 0902.R1

xn Line•Wyoming, Ontario•N0N 1T0
9-8868•Email: joe@electek.ca•Pager: (519) 333-3532
TIM MEREDITH: (519) 312-0061•Fax: (519) 845-1304•Email: tim@electek.ca•Pager: (519) 333-2526

APPENDIX 15



BLUEWATER POWER DISTRIBUTION CORPORATION

FIELD INTERRUPTION REPORT - 2007

Report # 105

Operator : Dales,G

Outage ☑ **Callout** ☐ **City** Sarnia

Cause : 1-Scheduled Outage **Related Outages:**

Date: 2007-05-02 **Time :** 13:36 **Time of Arrival:**

Date On: 2007-05-02 **Time On :** 15:14 **Callout Type :** N/A

Auto : ☑ A/R only - time off less than 1 min

No of CUST 2 **Customer Name:**

Total Time Off in Minutes 98 **Address:**

Customer minutes Off 196 **Phone #:** 0

Comments : Planned conversion to 16.2

Outage Information

Type of Fault OVERHEAD **Voltage :** 4.8

Feeder : 9F2 **Transformer** A4002

Defective Equipment : None **Designation :** A4002

Interruption Device : Fuse Disconnect **Restored By :** Fuse Disconnect

POLICE REPORT (If applicable) ☑ Officer :

Incident # 0 Badge # 0

FINANCE DEPARTMENT - CALLOUT TIMESHEET

S.A.P # 0

EMPLOYEE	TIME IN	TIME OUT	TOTAL TIME (h	EMPLOYEE	TIME IN	TIME OUT	TOTAL TIME (h

APPENDIX 16

Location ID	Cycle	Target Inspection Date	Target Completion Date	Issue Date	Completion Date	Status	Next Inspection Date
Sarnia1	3 year				August 2010	Complete	August 2013
Sarnia2	3 year				July 2010	Complete	July 2013
Sarnia3	3 year				March 2011	Complete	March 2014
Sarnia4	3 year				May 2011	Complete	May 2014
Sarnia5	3 year						
Sarnia6	3 year						
Sarnia7	3 year				May 2011	Complete	May 2014
Sarnia8	3 year						
Sarnia9	3 year				January 2011	Complete	January 2014
Sarnia10	3 year				January 2011	Complete	January 2014
Sarnia11	3 year						
Sarnia12	3 year						
Sarnia13	3 year						
Sarnia14	3 year	July 2011	July 2011	July 2011	July 28, 2011	Complete	July 2014
Sarnia15	3 year				October 2010	Complete	October 2013
Sarnia16	3 year				October 2010	Complete	October 2013
Sarnia17	3 year						
Sarnia18	3 year						
Sarnia19	3 year						
Sarnia20	3 year						
Sarnia21	3 year				June 2011	Complete	June 2014
Sarnia22	3 year						
Sarnia23	3 year						
Sarnia24	3 year						
Sarnia25	3 year						

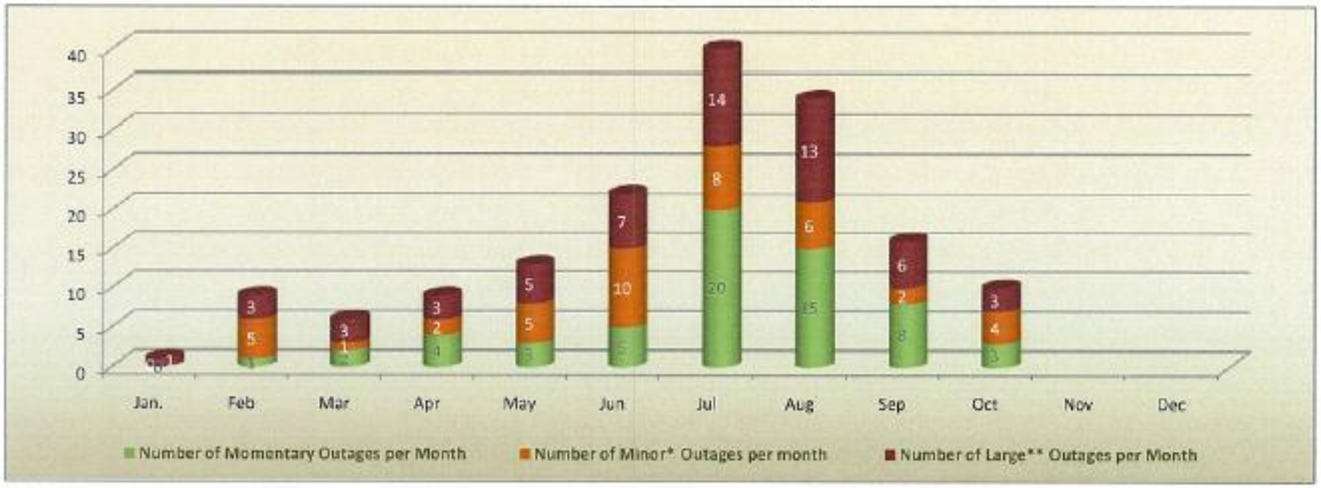
APPENDIX 17

Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	0	1	2	4	3	5	20	15	8	3			61
Number of Minor* Outages per month	0	5	1	2	5	10	8	6	2	4			43
Number of Large** Outages per Month	1	3	3	3	5	7	14	13	6	3			58
Number of Scheduled Outages per Month	5	7	10	5	7	15	11	15	8	13			96
Total Outages per Month	6	16	16	14	20	37	53	49	24	23	0	0	258

Momentary Outages are classified as outages under one minute in duration
**Minor outages are classified as outages over one minute in duration that affect less than 15 customers and do not include scheduled outages*
***Large outages are classified as outages over one minute in duration that affect over 15 customers and do not include scheduled outages*

Large Outage Causes	#
Animal Interference	5
Foreign Interference	7
Defective Equipment	27
Human Element	2
Loss of Supply	0
Tree Contacts	8
Unknown	1
Adverse Weather	8
Does not include Scheduled Outages	58

30153 Customers

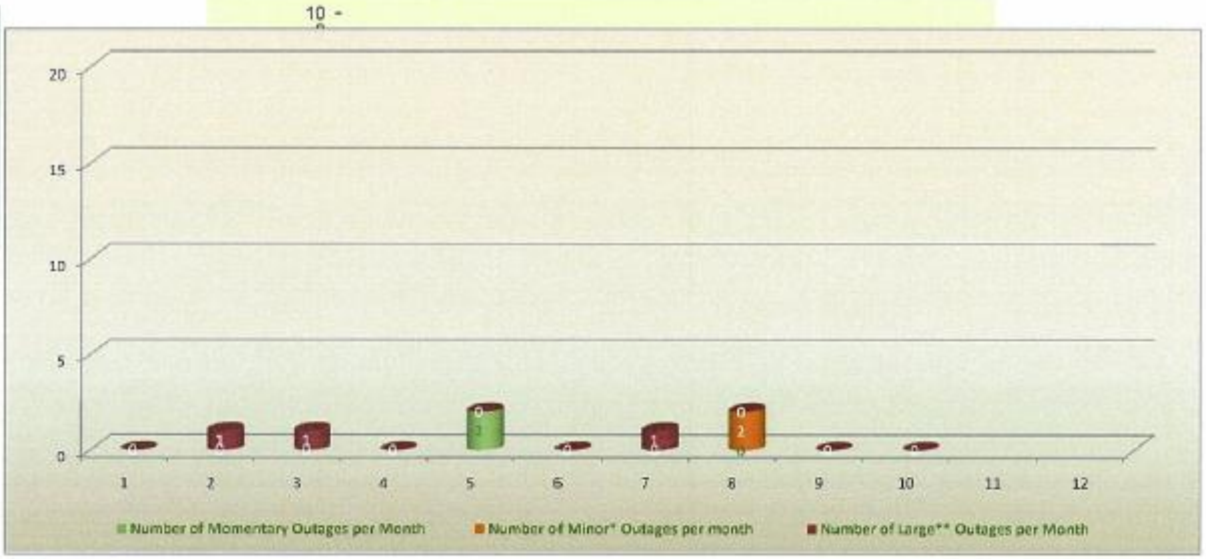


Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	0	0	0	0	2	0	0	0	0	0			**2**
Number of Minor* Outages per month	0	0	0	0	0	0	0	2	0	0			**2**
Number of Large** Outages per Month	0	1	1	0	0	0	1	0	0	0			**3**
Number of Scheduled Outages per Month	0	0	0	0	0	0	1	0	0	0			**1**
Total Outages per Month	**0**	**1**	**1**	**0**	**2**	**0**	**2**	**2**	**0**	**0**	**0**	**0**	**8**

Momentary Outages are classified as outages under one minute in duration
**Minor outages are classified as outages over one minute in duration that affect less than 15 customers and do not include scheduled outages*
***Large outages are classified as outages over one minute in duration that affect over 15 customers and do not include scheduled outages*

Large Outage Causes	#
Animal Interference	
Foreign Interference	1
Defective Equipment	
Human Element	
Loss of Supply	2
Tree Contacts	
Unknown	
Adverse Weather	
Does not include Scheduled Outages	**3**

403 Customers



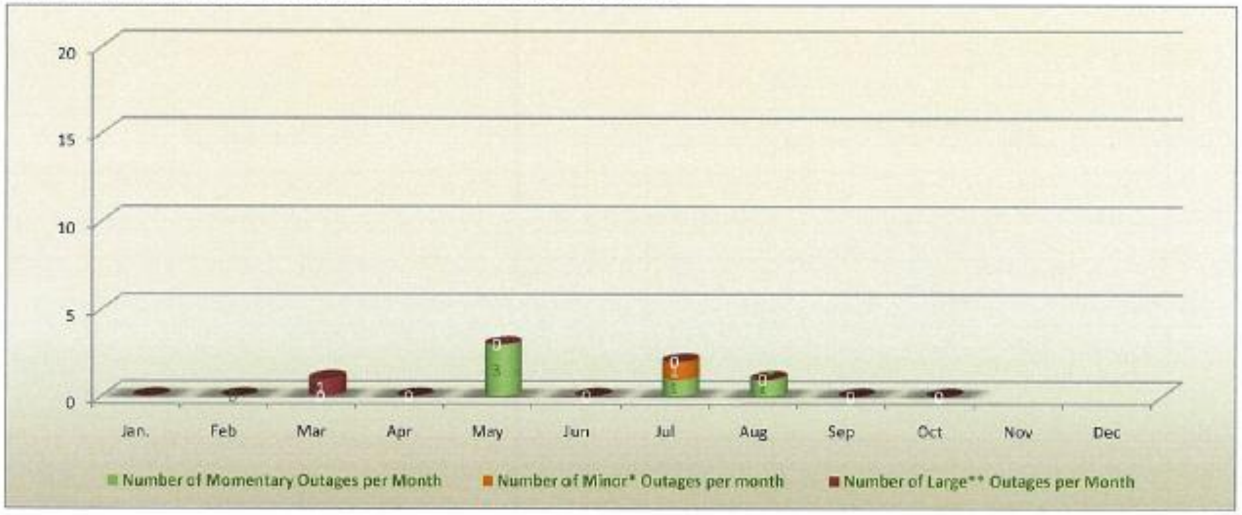
2010 Oil Springs Outage Causes (does not include Scheduled Outages)

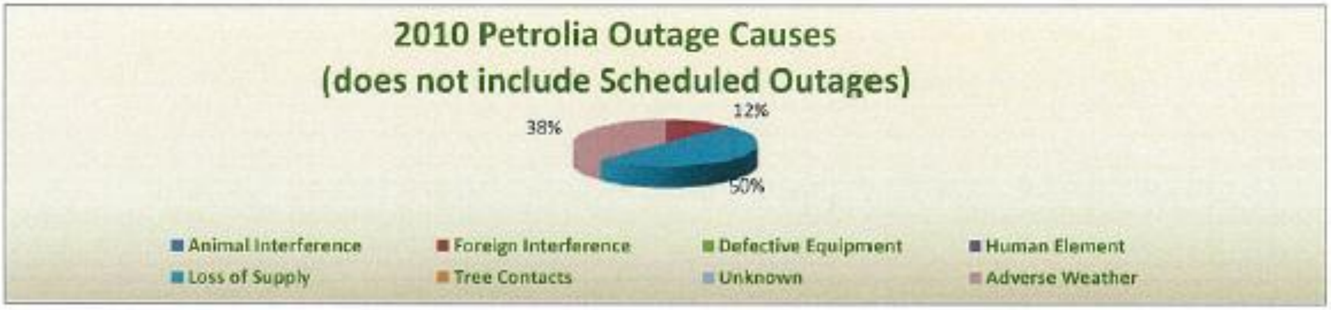
Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	0	0	0	0	3	0	1	1	0	0			5
Number of Minor* Outages per month	0	0	0	0	0	0	1	0	0	0			1
Number of Large** Outages per Month	0	0	1	0	0	0	0	0	0	0			1
Number of Scheduled Outages per Month	0	0	0	0	0	0	1	0	0	0			1
Total Outages per Month	0	0	1	0	3	0	3	1	0	0	0	0	8

Momentary Outages are classified as outages under one minute in duration
**Minor outages are classified as outages over one minute in duration that affect less than 15 customers and do not include scheduled outages*
***Large outages are classified as outages over one minute in duration that affect over 15 customers and do not include scheduled outages*

Large Outage Causes	#
Animal Interference	
Foreign Interference	
Defective Equipment	
Human Element	
Loss of Supply	1
Tree Contacts	
Unknown	
Adverse Weather	
Does not include Scheduled Outages	1

378 Customers



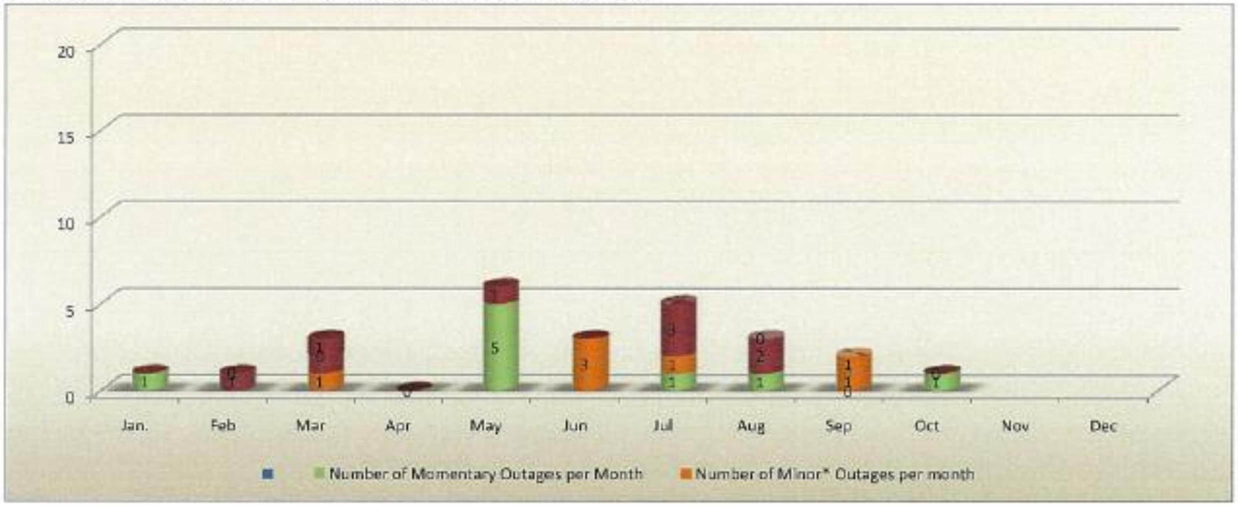


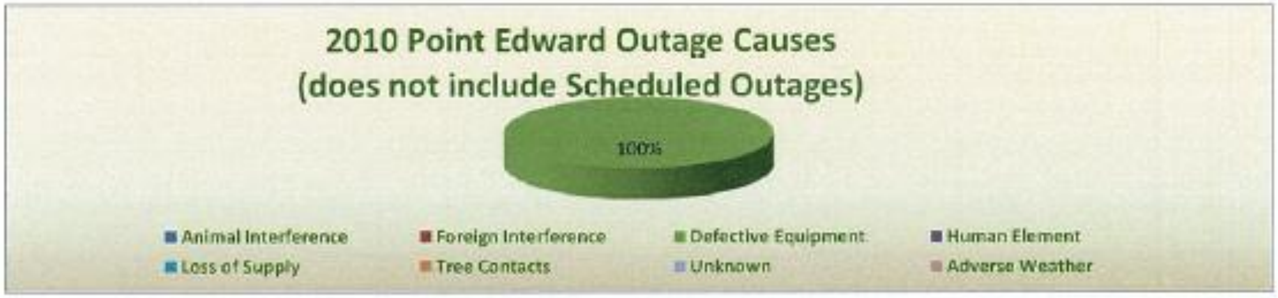
Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	0	0	0	0	5	0	1	1	0	1			8
Number of Minor* Outages per month	0	0	1	0	0	3	1	0	1	0			6
Number of Large** Outages per Month	0	1	1	0	1	0	3	2	0	0			8
Number of Scheduled Outages per Month	1	1	5	4	5	2	0	3	0	1			22
Total Outages per Month	1	2	7	4	11	5	5	6	1	2	0	0	44

Momentary Outages are classified as outages under one minute in duration
**Minor outages are classified as outages over one minute in duration that affect less than 15 customers and do not include scheduled outages*
***Large outages are classified as outages over one minute in duration that affect over 15 customers and do not include scheduled outages*

Large Outage Causes	#
Animal Interference	
Foreign Interference	1
Defective Equipment	
Human Element	
Loss of Supply	4
Tree Contacts	
Unknown	
Adverse Weather	3
Does not include Scheduled Outages	8

2260 Customers





Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	1	0	0	0	0	0	0	0	0	0			1
Number of Minor* Outages per month	0	0	0	0	0	0	0	0	1	0			1
Number of Large** Outages per Month	0	0	1	0	0	0	0	0	0	0			1
Number of Scheduled Outages per Month	0	0	1	0	0	0	0	0	0	0			1
Total Outages per Month	1	0	2	0	0	0	0	0	1	0	0	0	4

Momentary Outages are classified as outages under one minute in duration
**Minor outages are classified as outages over one minute in duration that affect less than 15 customers and do not include scheduled outages*
***Large outages are classified as outages over one minute in duration that affect over 15 customers and do not include scheduled outages*

Large Outage Causes	#
Animal Interference	
Foreign Interference	
Defective Equipment	1
Human Element	
Loss of Supply	
Tree Contacts	
Unknown	
Adverse Weather	
Does not include Scheduled Outages	1

1131 Customers

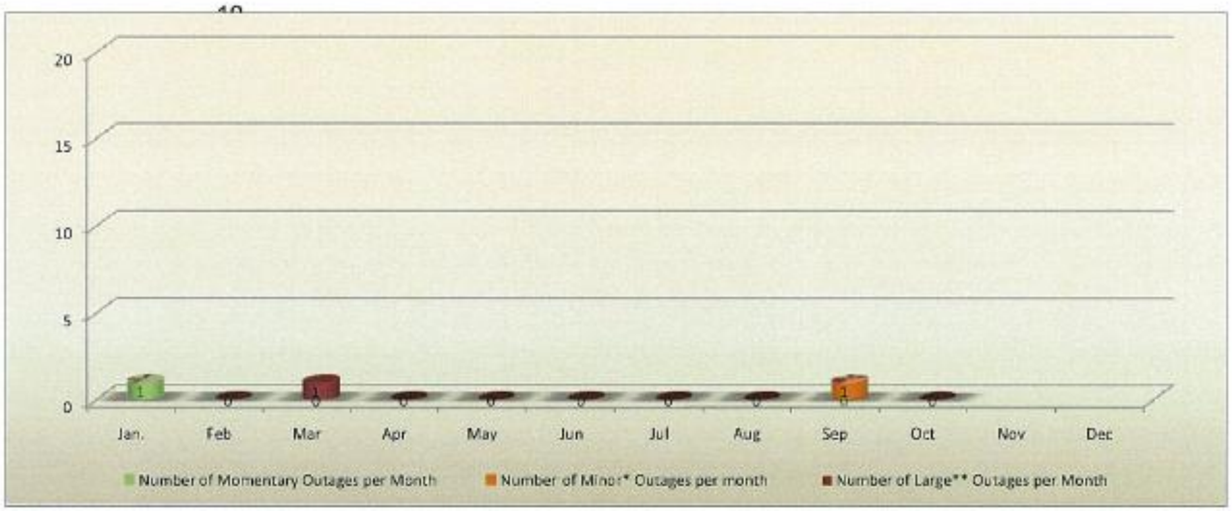


Figure 3

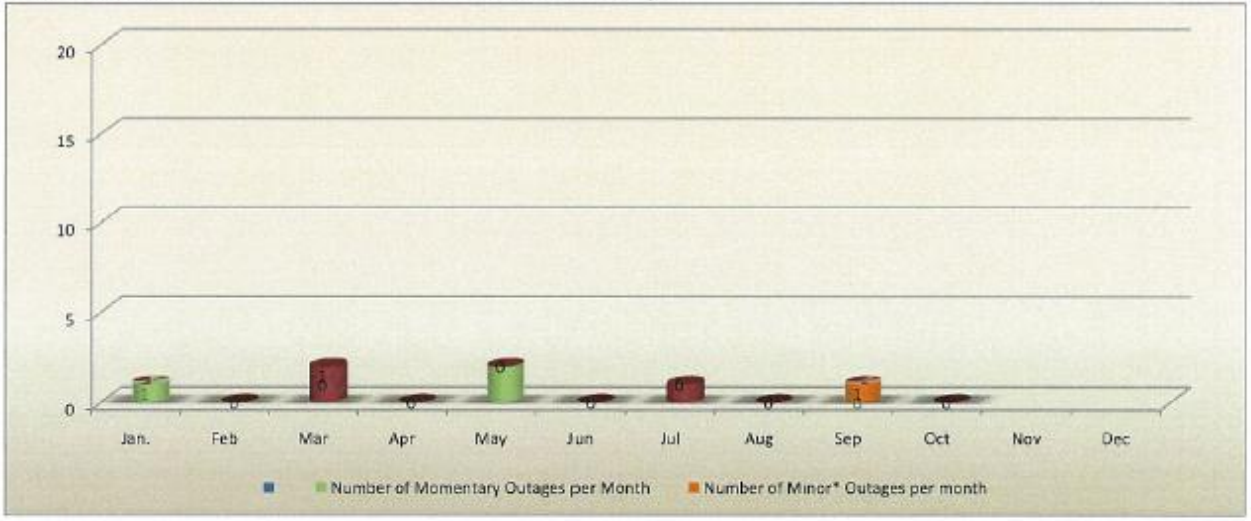
2010 Watford Outage Causes
(does not include Scheduled Outages)

Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	0	0	0	0	2	0	0	0	0	0			2
Number of Minor* Outages per month	0	0	0	0	0	0	0	0	0	0			0
Number of Large** Outages per Month	0	0	1	0	0	0	1	0	0	0			2
Number of Scheduled Outages per Month	0	0	0	0	0	0	1	0	0	0			1
Total Outages per Month	0	0	1	0	2	0	2	0	0	0	0	0	5

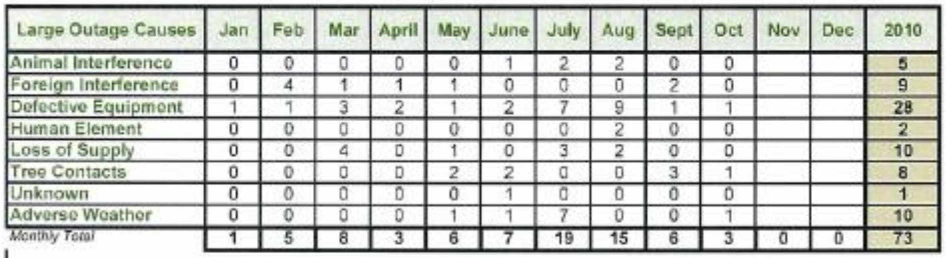
Momentary Outages are classified as outages under one minute in duration
**Minor outages are classified as outages over one minute in duration that affect less than 15 customers and do not include scheduled outages*
***Large outages are classified as outages over one minute in duration that affect over 15 customers and do not include scheduled outages*

Large Outage Causes	#
Animal Interference	
Foreign Interference	
Defective Equipment	
Human Element	
Loss of Supply	2
Tree Contacts	
Unknown	
Adverse Weather	
Does not include Scheduled Outages	2

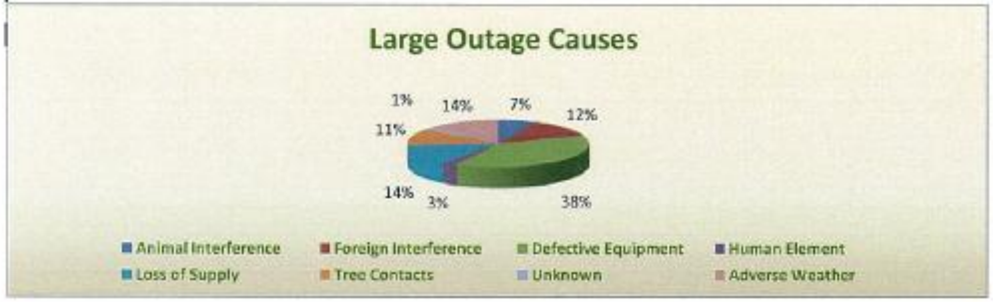
769 Customers



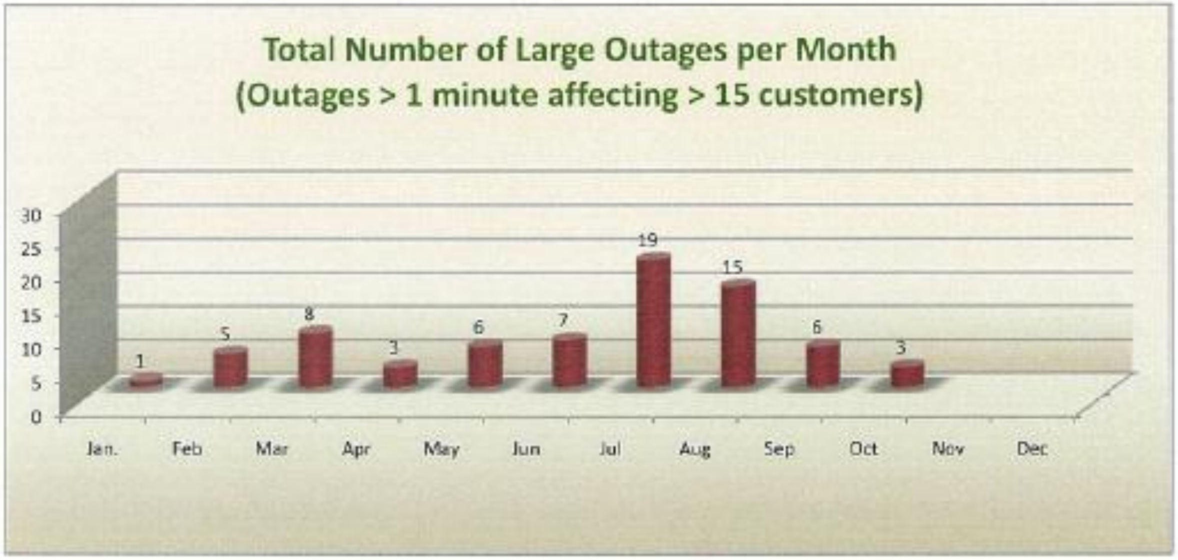
Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Number of Momentary Outages per Month	1	1	2	4	15	5	22	17	8	4			**79**
Number of Minor** Outages per month	0	5	2	2	5	13	10	8	4	4			**53**
Number of Large* Outages per Month	1	5	8	3	6	7	19	15	6	3			**73**
Number of Scheduled Outages per Month	6	8	16	9	12	17	14	18	8	14			**122**
Total Outages per Month	**8**	**19**	**28**	**18**	**38**	**42**	**65**	**58**	**26**	**25**	**0**	**0**	**327**



Large Outage Causes	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	2010
Animal Interference	0	0	0	0	0	1	2	2	0	0			**5**
Foreign Interference	0	4	1	1	1	0	0	0	2	0			**9**
Defective Equipment	1	1	3	2	1	2	7	9	1	1			**28**
Human Element	0	0	0	0	0	0	0	2	0	0			**2**
Loss of Supply	0	0	4	0	1	0	3	2	0	0			**10**
Tree Contacts	0	0	0	0	2	2	0	0	3	1			**8**
Unknown	0	0	0	0	0	1	0	0	0	0			**1**
Adverse Weather	0	0	0	0	1	1	7	0	0	1			**10**
Monthly Total	1	5	8	3	6	7	19	15	6	3	0	0	73



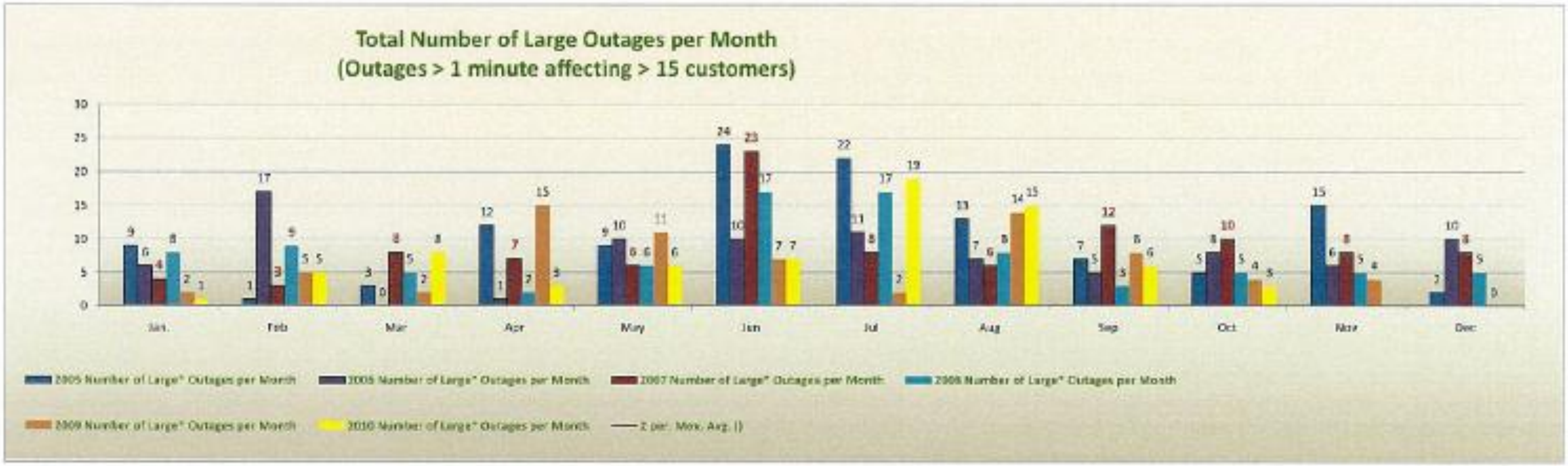
Large Outage Causes

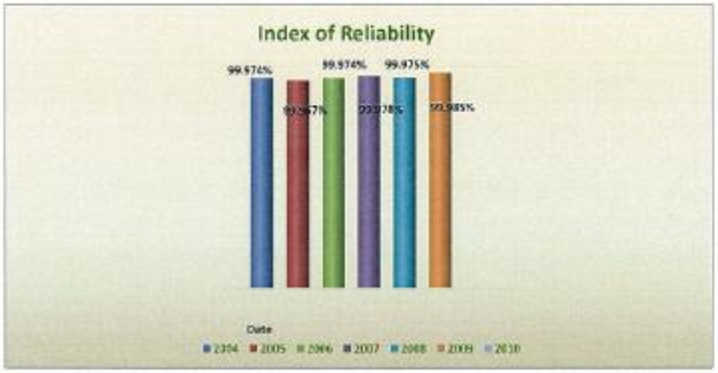

Total Number of Large Outages per Month
(Outages > 1 minute affecting > 15 customers)
30
25
20
15
10
5
0
1
5
8
3
6
7
19
15
6
3
Jan.
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

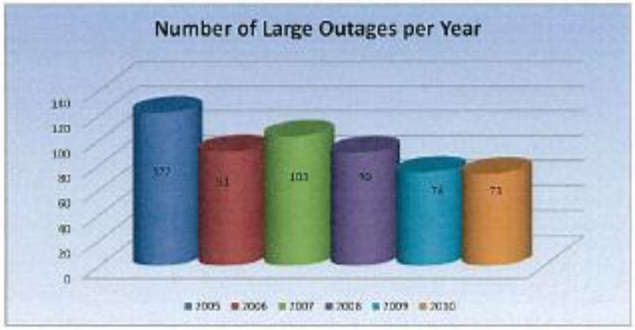
Outage Classification	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2005 Number of Large* Outages per Month	9	1	3	12	9	24	22	13	7	5	15	2	122
2006 Number of Large* Outages per Month	6	17	0	1	10	10	11	7	5	8	6	10	91
2007 Number of Large* Outages per Month	4	3	8	7	6	23	8	6	12	10	8	8	103
2008 Number of Large* Outages per Month	8	9	5	2	6	17	17	8	3	5	5	5	90
2009 Number of Large* Outages per Month	2	5	2	15	11	7	2	14	8	4	4	0	74
2010 Number of Large* Outages per Month	1	5	8	3	6	7	19	15	6	3			73

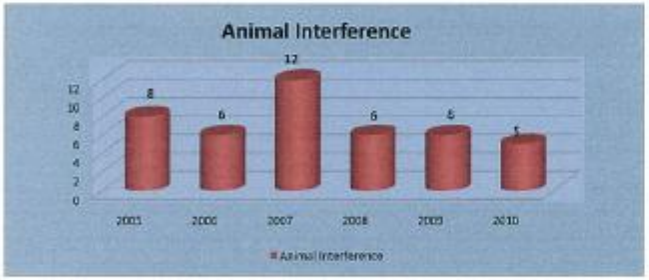
Large Outage Causes	2005	2006	2007	2008	2009	2010	Total
Animal Interference	8	6	12	6	6	5	43
Foreign Interference	7	7	10	13	4	9	50
Defective Equipment	42	26	26	35	28	28	183
Human Element	2	0	3	1	2	2	10
Loss of Supply	21	0	12	2	15	10	60
Tree Contacts	9	9	11	9	3	8	49
Unknown	14	7	9	5	4	1	40
Adverse Weather	19	36	20	19	14	10	118
Monthly Total	122	91	103	90	74	73	

Index of Reliability	
2004	99.974%
2005	99.967%
2006	99.974%
2007	99.978%
2008	99.975%
2009	99.985%
2010	



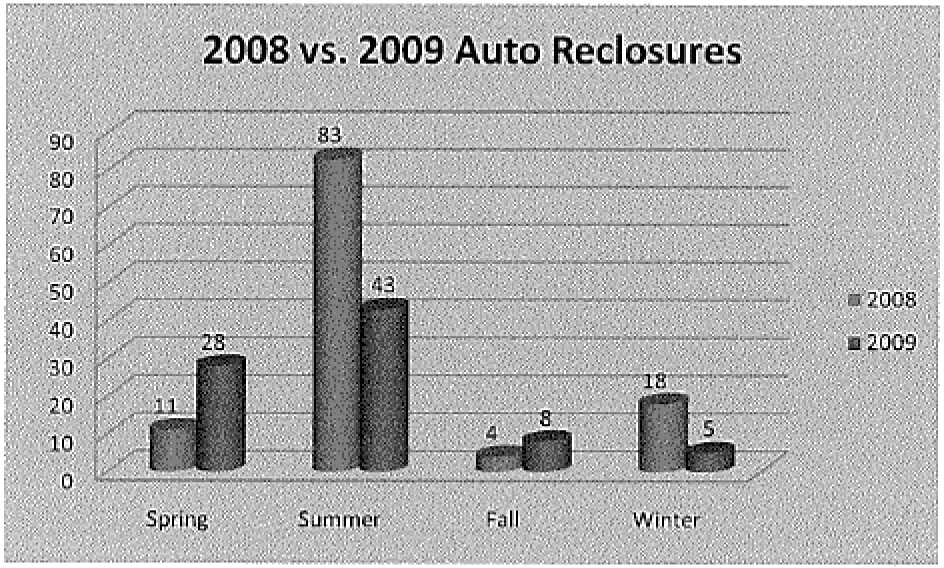

Index of Reliability
99.974%
99.967%
99.974%
99.978%
99.975%
99.985%
Date
2004
2005
2006
2007
2008
2009
2010

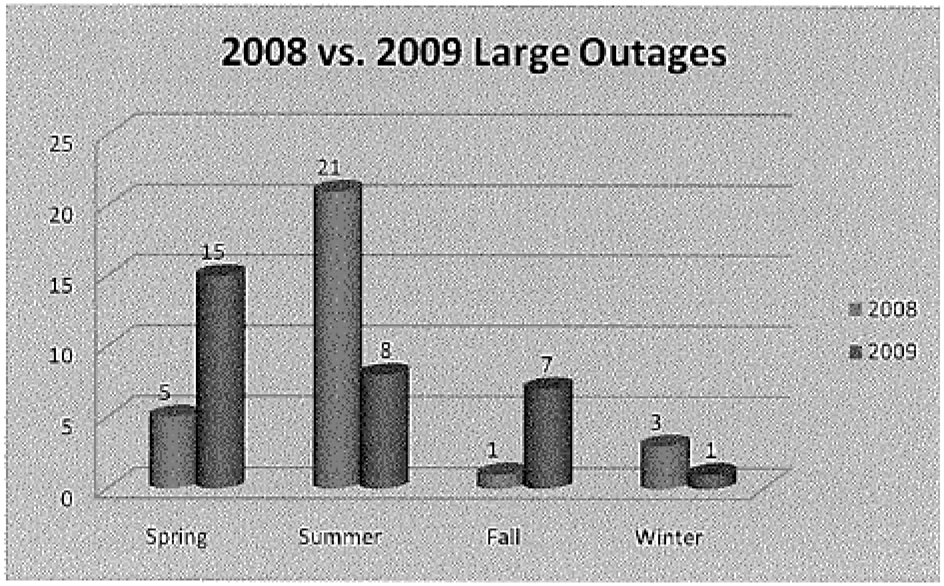

Number of Large Outages per Year
140
120
100
80
60
40
20
0
122
91
103
90
74
73
2005
2006
2007
2008
2009
2010

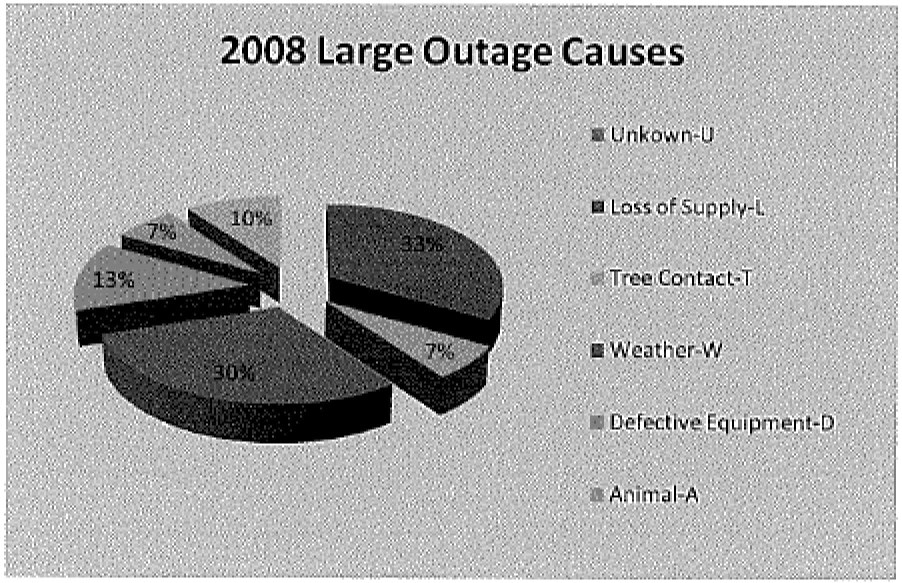

Animal Interference
12
10
8
6
4
2
0
8
6
12
6
6
5
2005
2006
2007
2008
2009
2010
Animal Interference

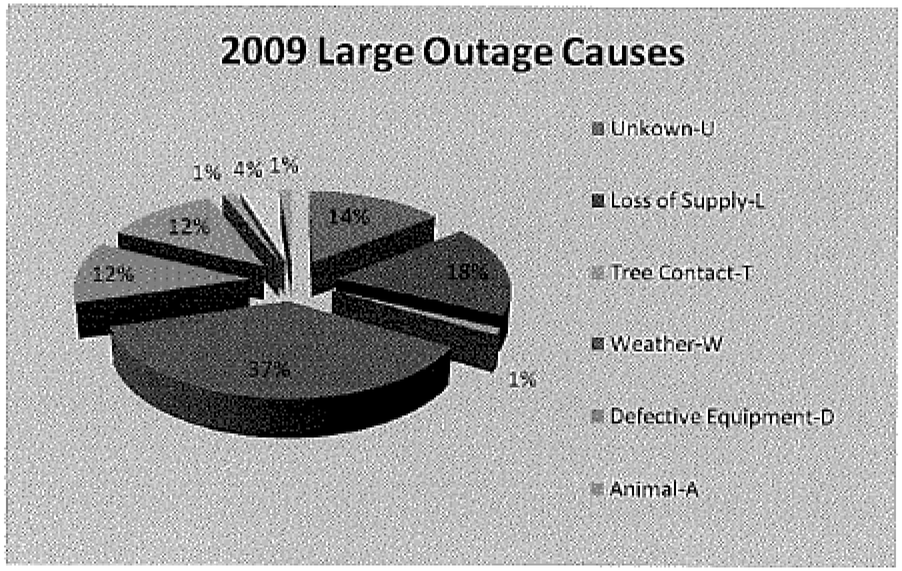

Tree Contacts
12
10
8
6
4
2
0
9
9
11
9
3
8
2005
2006
2007
2008
2009
2010
Tree Contacts

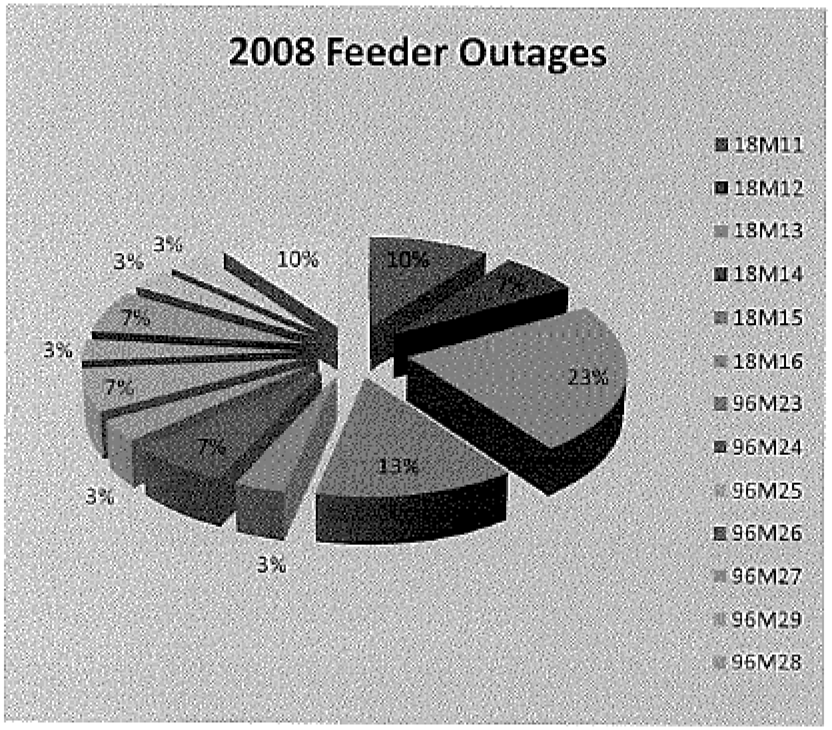
APPENDIX 18

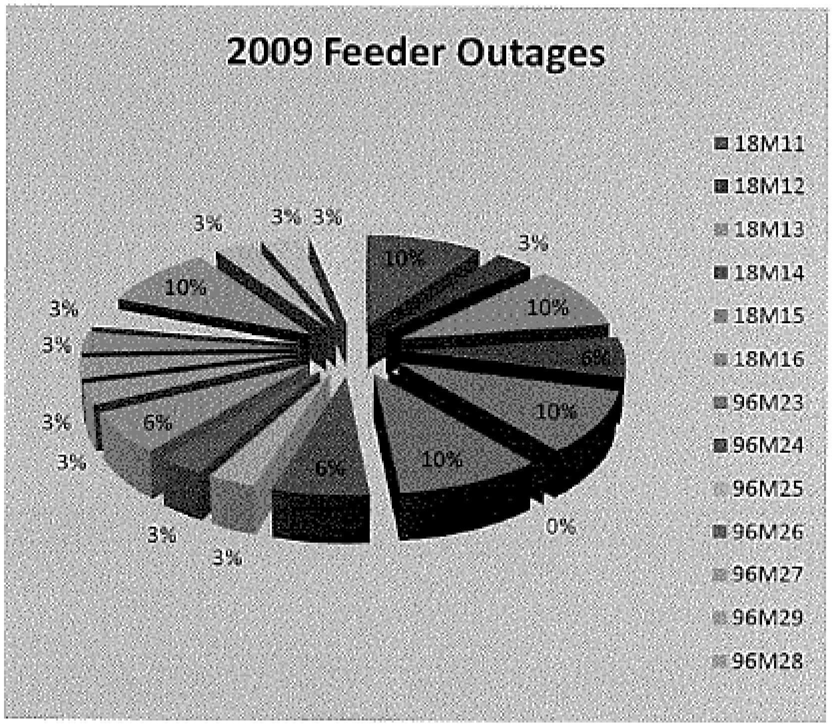

2008 vs. 2009 Auto Reclosures
90
80
70
60
50
40
30
20
10
0
11
28
83
43
4
8
18
5
Spring
Summer
Fall
Winter
2008
2009


2008 vs. 2009 Large Outages
25
20
15
10
5
0
5
15
21
8
1
7
3
1
Spring
Summer
Fall
Winter
2008
2009


2008 Large Outage Causes
10%
7%
13%
33%
7%
30%
Unkown-U
Loss of Supply-L
Tree Contact-T
Weather-W
Defective Equipment-D
Animal-A


2009 Large Outage Causes
1%
4%
1%
12%
12%
14%
18%
37%
1%
Unkown-U
Loss of Supply-L
Tree Contact-T
Weather-W
Defective Equipment-D
Animal-A


2008 Feeder Outages
10%
7%
23%
13%
3%
7%
3%
7%
3%
7%
3%
3%
10%
18M11
18M12
18M13
18M14
18M15
18M16
96M23
96M24
96M25
96M26
96M27
96M29
96M28


2009 Feeder Outages
10%
3%
10%
6%
10%
10%
0%
6%
3%
3%
6%
3%
3%
3%
3%
10%
3%
3%
3%
18M11
18M12
18M13
18M14
18M15
18M16
96M23
96M24
96M25
96M26
96M27
96M29
96M28

APPENDIX 19

Operations Leading Indicators

Pole Inspections

Items Inspected & Replaced:

- ✓Rotten poles
- ✓Guy Guards
- ✓Cross Arms
- ✓Caps & Pins

Our goal is to perform at least 75 pole maintenance work orders per year

Operations Leading Indicators

Rotten Poles Found as a Result of Pole Testing

Our goal is to replace at least 5 rotten poles per year

Operations Leading Indicators

Pole Inspections

Items Inspected & Replaced:

- ✓Rotten poles
- ✓Guy Guards
- ✓Cross Arms
- ✓Caps & Pins

Our goal is to perform at least 75 pole maintenance work orders per year

Operations Leading Indicators

Rotten Poles Found as a Result of Pole Testing

Our goal is to replace at least 5 rotten poles per year

Operations Leading Indicators

Poles Inspected Annually

*Our goal is to inspect at least
(one third) of our poles annually*

Appendix C

Needs Assessment

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: Chatham-Kent/Lambton/Sarnia

Date: September 30, 2021

Prepared by: Chatham-Kent/Lambton/Sarnia Study Team

This report is prepared on behalf of the Chatham-Kent/Sarnia/Lambton regional planning study team with the participation of representatives from the following organizations:

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Bluewater Power Distribution Corporation
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Chatham-Kent/Lambton/Sarnia and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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 Needs Assessment 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 Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), 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 Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

NAME	Chatham-Kent/Lambton/Sarnia Study Team		
LEAD	Hydro One Networks Inc.		
REGION	Chatham-Kent/Lambton/Sarnia		
START DATE	June 4, 2021	**END DATE**	September 30, 2021

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Chatham-Kent/Lambton/Sarnia Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

In response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013, the first cycle of regional planning process for the Chatham-Kent/Lambton/Sarnia Region began with Needs Assessment in April 2016 and was completed in August 2017 with the Regional Infrastructure Plan. In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of this mandate, the Needs Assessment for the 2nd Regional Planning cycle for Chatham-Kent/Lambton/Sarnia Region was triggered on June 4th 2021 and completed on September 30, 2021.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the OEB.

The scope of the Needs Assessment includes a review of transmission system capability which covers transformer station capacity, transmission circuit thermal capacity, voltage performance and load restoration. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle. If required, an IRRP will develop a 20-year strategic direction for the Region.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Chatham-Kent/Lambton/Sarnia Region. The information included: planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, system reliability performance, operational issues and major equipment approaching end-of-life (EOL).

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2021 – 2030). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformer Capacity

- Based on the gross regional-coincident load forecast, the 230/115 kV autotransformer capacity (Scott TS) supplying the Region is adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- Based on the gross regional-coincident load forecast, the 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region, under the assumption that an IESO bulk system study is recommending reinforcement of the 230 kV Lambton-by-Chatham corridor to resolve thermal violations with additional load growth at Dresden and in Windsor-Essex.

C. 115 kV Transmission Lines

- Based on the gross regional-coincident load forecast, the 115 kV circuits supplying the Region are adequate over the study period for the loss of a single 115 kV circuit in the Region. However, if we consider the drastic load growth that could occur at Wallaceburg TS in the absence of a new Dresden area station, the 115kV circuit supplying Wallaceburg TS would exceed its thermal rating.

D. 230 kV and 115 kV Connection Facilities

- Large customer connection requests at Wallaceburg TS would result in the Limited Time Rating (LTR) being exceeded in 2022, however facilitating these connections on the proposed Dresden TS would result in adequate supply at Wallaceburg TS over the study period. A separate study team was formed in October 2019 to work on the Dresden area load connection requests that proposed that the best connection point for additional load would be a new load station is in the Dresden area (Dresden TS), however the results were deferred until the IESO's bulk study was conducted, which was recently published on September 23, 2021.

System Reliability, Operation and Restoration Needs

A. Load Security

- Based on the gross regional-coincident load forecast and the existing transmission configuration, load security criteria can be met over the study period.

B. Load Restoration

- Based on the gross regional-coincident load forecasts with the use of existing transmission infrastructure, restoration criteria can be met over the study period.

C. Voltage Performance

- Under gross regional-coincident peak load conditions, post-contingency voltage at all transformer stations in the region meet Market Rule requirements.

D. Bulk Power System Performance in the Region

- Based on the assumed system study conditions and needs in neighbouring regions, a bulk power system issue was identified in the Region. Reinforcement of the 230kV corridor between Lambton TS and Chatham TS is required.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at stations and several transmission circuits will take place. Further details of these investments can be found in Section 6.4 of this report.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that regional planning is required to develop a plan to address the high demand for capacity near Wallaceburg TS as well as a plan to coordinate the connection of the proposed Dresden TS with bulk recommendations in the area.

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1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Chatham-Kent/Lambton/Sarnia (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the Planning Process Working Group (PPWG) Report to the OEB.

The purpose of this second cycle Needs Assessment report is to: review the status of needs identified in the previous Regional Planning cycle; consider the information from planning activities already underway; undertake an assessment of the Chatham-Kent/Lambton/Sarnia Region to identify near-term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires-only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Chatham-Kent/Lambton/Sarnia Region Needs Assessment study team listed in Table 1. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1: Study team participants for Chatham-Kent/Lambton/Sarnia Region

No.	Organizations
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Bluewater Power Distribution Corporation
4.	Entegrus Power Lines Inc.
5.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

In response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013, the first cycle of regional planning process for the Chatham-Kent/Lambton/Sarnia Region began with the Needs Assessment in April 2016 and was completed in August 2017 with the Regional Infrastructure Plan. In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of this mandate, the Needs Assessment for the 2nd Regional Planning cycle for Chatham-Kent/Lambton/Sarnia Region was triggered on June 4th 2021 and completed on September 30, 2021.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Chatham-Kent/Lambton/Sarnia Region over an assessment period of 10 years, from 2021 to 2030. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuit thermal capacity, voltage performance and load restoration. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Chatham-Kent/Lambton/Sarnia Region Description and Connection Configuration

The region includes the municipalities of Lambton Shores and Chatham-Kent, as well as the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. The area is bordered by the London area to the east and Windsor-Essex to the southwest.
Figure 1 illustrates the approximate study area.

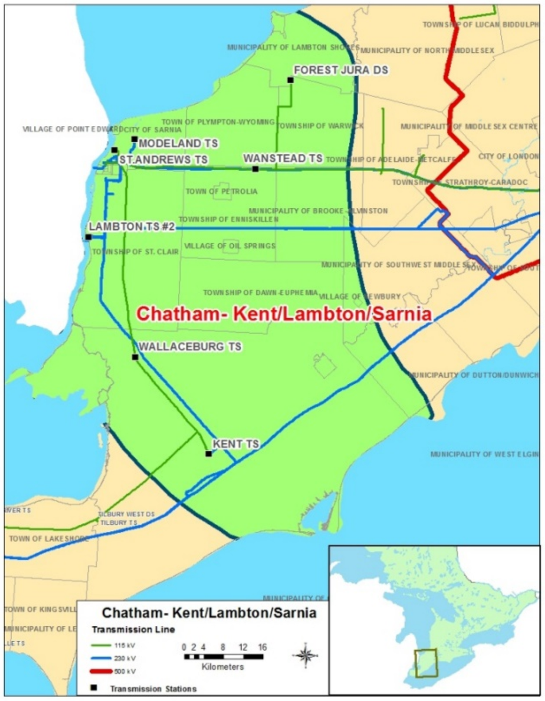


Figure 1: Map of Chatham-Kent/Lambton/Sarnia Region

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines. The bulk of the electrical supply is transmitted through 230 kV circuits (N21W, N22W, L24L, L26L, W44LC and W45LS) between Longwood TS/Buchanan TS and Lambton TS/Scott TS/Chatham SS, and 230 kV circuits L28C and L29C towards Chatham SS. This Region also contains a number of interconnections with neighboring Michigan State (B3N, L4D and L51D)

Listed in Table 2 and shown in Figure *2* are Hydro One transmission and transmission-connected customers' assets in the Chatham-Kent/Lambton/Sarnia Region.

Table 2: Hydro One and customer assets in Chatham-Kent/Lambton/Sarnia Region

115 kV Circuits	230 kV Circuits	Hydro One Transformer Stations	Customer Transformer Stations
N1S, N4S, N6C, N7C, S2N, N5K, K2Z	N6S, N7S, V41N, V43N, L23N, L27V, L25V, L37G, L38G, L28C, L29C, C31, W44LC, W45LS, S47C, L24L, L26L, N21W, N22W	Scott TS, Lambton TS, Kent TS, Duart TS, Modeland TS, Wanstead TS, St. Andrew TS, Wallaceburg TS	Forest Jura HVDS, CTS #1, CTS #2, CTS #3, CTS #4, CTS #5, CTS #6, CTS #7, CTS #8, CTS #9

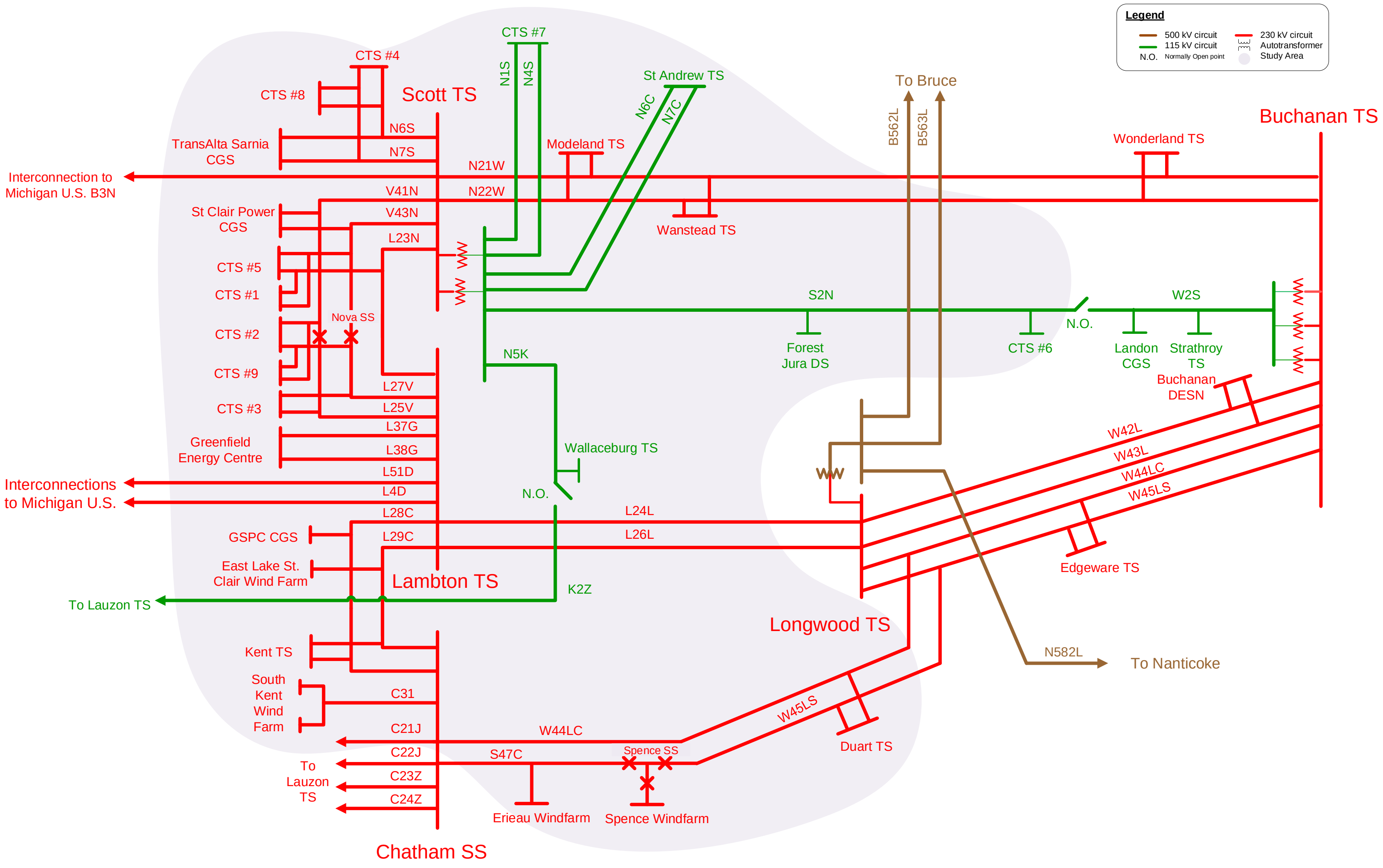


Figure 2: Single-Line diagram – Chatham-Kent/Lambton/Sarnia Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- LDCs and transmission-connected industrial customers provided historical summer and winter peak load (2018 – 2020) as well as summer and winter gross load forecast (2021 – 2030). In cases where industrial customers did not provide data, the historical peaks and forecasts were provided by Hydro One's forecasting group.
- IESO provided:
  a. List of existing reliability and operational issues
  b. Gas generation assumptions
  c. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- Hydro One (Transmission) provided:
  a. Transformer, station and circuit ratings
  b. Historical regional coincident peak load and station non-coincident peak load (IESO-verified data)
  c. Existing reliability and operation issues
- Any relevant planning information, including planned transmission and distribution investments are provided by Hydro One (Transmission) and LDCs

Based on the historical information provided, Chatham-Kent/Lambton/Sarnia Region is a summer peaking region. As such, the Needs Assessment was conducted based on summer peak load and study conditions. Further, as Hydro One Distribution has received a significant number of new customer connection requests in the area close to Kent TS and Wallaceburg TS (both stations have very limited available capacity), a new proposed station (Dresden TS) connected to 230kV circuits L28C/L29C was modelled to supply these new customer connections totaling up to 129 MW of new load. Since Dresden TS load is expected to be winter-peaking and coincides with the winter-peaking Windsor-Essex region, a winter assessment was undertaken to identify thermal violations that are expected to arise on circuits L28C/L29C. The location and connection of a new station will require further regional coordination.

4.1 Load Forecast

Based on data provided by the study team, the load in the Region is expected to grow at an average rate of approximately 2.2% annually from 2021 – 2030, with a strong average growth rate of 3.6% from 2021 to 2025 that steps down to 1.1% for the remaining 5 years of the forecast.

Initially, the load forecast for Wallaceburg TS included large customer connection requests and resulted in the station exceeding its 10-day LTR in 2022. This initial forecast reached 112 MW by 2030 at Wallaceburg TS where the summer LTR is 51.8MVA. The study team agreed that assuming such an aggressive load growth at Wallaceburg TS was not realistic, and determined that a separate forecast be created to capture the potential new customer connections that could be supplied by the proposed new Dresden TS. The forecast for the proposed Dresden TS was included in this study.

Please refer to Appendix A for the load forecasts utilized for this Needs Assessment.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The assessment considered summer and winter peak loads.
2. Load forecasts are provided by the Region's LDCs and industrial customers using historical 2020 summer peak loads as reference points.
3. The historical peak loads at Hydro One's stations are adjusted for extreme weather conditions according to Hydro One methodology.
4. The LDC and industrial customer load forecast is translated into load growth rates and is applied onto the historical, extreme weather adjusted, reference points.
5. The DG contribution is not applied to the forecast because the historical peaks used as reference points, which already accounts for existing DGs and no additional contracted DGs are forecast to connect in the planning horizon..
6. Accounting for (2), (3), (4), and (5) above, and applying CDM reductions, a net non-coincident load forecast and a net coincident load forecast are developed.
    - A net non-coincident peak load forecast was used to perform the analysis for sections 6.2.4
    - A net regional coincident peak load forecast was used to perform the analysis for sections 6.2.1 to 6.2.3, 6.3.1, 6.3.2 and 6.3.4
7. Review impact of any on-going and planned development projects in the Region during the study period.
8. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as transformers, cables, and stations.
9. 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 and 95% lagging power factor for stations having low-voltage capacitor banks. Normal planning supply capacity for

transformer stations in this Region is determined by the summer 10 – Day Limited Time Rating (LTR).

10. Transmission adequacy assessment is primarily based on the following criteria:
    - Regional load is set to the forecasted regional coincident peak load. Large load increases in neighbouring regions are also considered as they affect the thermal loading of circuits in CKLS region.
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long term emergency (LTE) ratings and transformers within their 10 – Day LTR.
    - All voltages must be within pre and post contingency ranges as per the Ontario Resource and Transmission Assessment Criteria (ORTAC).
    - The system to meet load security criteria as per the ORTAC, specifically, with one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - The system is capable of meeting the load restoration timeframes as per the ORTAC.

6 NEEDS

This section assesses the adequacy of regional infrastructure to meet the forecasted load in the Chatham-Kent/Lambton/Sarnia Region and identifies needs. The section also reviews and/or reaffirms needs already identified in the last regional planning cycle.

6.1 Review of Identified Needs in the Last Regional Planning Cycle

This section reviews the status of needs identified in the previous cycle of Regional Planning.

Kent TS T3/T4 was forecasted to exceed its 10-day LTR in 2016 and resulted in a capacity need that was addressed by implementing a permanent distribution load transfer to nearby stations with available spare capacity.

No other needs were identified.

6.2 Transmission System Capacity Needs

6.2.1 230 kV and 115 kV Autotransformers

The 230/115 kV autotransformers (Scott TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.2.2 230 kV Transmission Lines

The 230 kV circuits are adequate over the study period for the loss of a single 230 kV circuit in the Region, however, the capacity needs in the Windsor Essex region and the Dresden area are resulting in voltage violations on circuits L28C/L28C and require the construction of another 230 kV double circuit supply between Lambton TS and Chatham SS. The recommendation for constructing the new double circuit is a result of IESO's bulk system study.

6.2.3 115 kV Transmission Lines

The 115 kV lines supplying the Region are radial single circuit lines. These 115 kV circuits have adequate capacity over the study period. However, considering drastic load growth due to new customer connection requests near Wallaceburg TS in absence of new Dresden TS, the 115 kV N5K circuit supplying Wallaceburg TS may be violating its capacity limits and risking the power system security.

6.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the summer station non- coincident peak load forecasts.

In the absence of the proposed Dresden TS, there is a very high demand for available capacity at Wallaceburg TS. Assuming the load materializes as forecasted, Wallaceburg TS would be exceeding it summer LTR in 2022 and its winter LTR in 2024. However, if the proposed Dresden TS is built to supply 129MW of new customer connections, Wallaceburg TS would have 5-10 MW of spare capacity available toward the end of the study period, assuming organic load growth at the station.

A separate study team was formed in October 2019 to work on the Dresden area load connection requests that proposed the optimal location of a new supply station (proposed Dresden TS) would be in the vicinity of existing Wallaceburg TS, connected to the Lambton-to-Chatham corridor. However, this would result in bulk transfer violations, and as a result a recommendation was deferred until after the IESO's West of London bulk plan was finalized. That bulk plan recommended a Lambton-to-Chatham reinforcement in 2028. Actions to facilitate the connection of Dresden TS ahead of that reinforcement in 2028 will require further regional coordination. With large demand for capacity in the Wallaceburg TS and Kent TS area starting in 2022, and at least 4-5 years before Dresden TS is constructed and 7 years until the Lambton-to-Chatham reinforcement is constructed, there is approximately 30-35 MW of available capacity at Kent TS (T1/T2) to facilitate the more immediate requests for capacity. This does not satisfy the forecasted demand in the area, so further regional planning is required to identify potential interim measures.

St. Andrews TS is expected to approach and exceed its existing LTR in the medium-term (5-10 years), however, the planned like-for-like replacement of the transformers and switchyard (2025 in-service) will increase the station capacity by 20 MVA and address the medium-term capacity need.

Forest Jura DS is approaching its LTR in the near-term. Loading at the station will be monitored by Hydro One Distribution to determine when the future need for additional capacity will be required.

All the other TSs in the Chatham-Kent/Lambton/Sarnia Region are forecasted to remain within their normal supply capacity during the study period.

6.3 System Reliability, Operation and Restoration Review

6.3.1 Load Security

Based on the gross regional coincident peak load forecast, with all transmission facilities in-service and coincident with an outage of the largest local generation units, all facilities are within applicable ratings. The largest local generation unit is a 230 kV-connected Greenfield Energy Centre unit on the 230 kV.

Based on the gross regional-coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Based on the gross regional coincident load forecast, the loss of two elements will not result in load interruption greater than 600 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Therefore, load security criteria for the Region are met.

6.3.2 Load Restoration

Based on the gross coincident load forecast at Modeland TS, Wanstead TS and Wonderland TS, by the end of study period, the load interrupted is expected to approach 300 MW for the loss of double-circuit 230 kV line N21W and N22W. Restoring load loss in excess of 250MW within 30 min can be achieved through distribution load transfers at Modeland TS and Wonderland TS. Furthermore, N21W can be sectionalized and load can be restored from either Scott TS or Buchanan TS by use of existing switches on N21W. With the switching capabilities, magnitude of load loss can be reduced from 250 MW to less than 150 MW within 4 hours. The remaining load can be resupplied within the 4-8 hour timeframe by means of load transfers and/or switching alternate feeder supplies to neighbouring, unaffected transformer stations. Hydro One will continue to monitor load growth at stations connected to N21W/N22W and update the restoration plan on an ongoing basis as appropriate.

Based on the assumed load levels for the transmission-connected industrial customers connected to N6S and N7S, the load interrupted will exceed 150 MW for the loss of double-circuit 230kV line N6S and N7S. Hydro One crews located in Sarnia will be able to respond as quickly as possible to restore load to meet the 4-hour and 8-hour restoration criteria. It is the customer’s accountability to ensure that there is onsite emergency supply for essential load or arrange for backup supply from other sources.

Therefore, load restoration criteria for the Region are met.

6.3.3 Voltage Performance

Assuming a large load growth at Wallaceburg TS in the absence of the proposed Dresden TS, there would be voltage violation occurring on the 115kV system supplying the Wallaceburg load. This violation would be mitigated with the proposed Dresden TS in place.

Under gross regional coincident peak load conditions, post-contingency voltage at all transformer stations in the region meet Market Rule requirements.

6.3.4 Bulk Power System Performance in the Region

Based on the study assumptions listed in Section 4, and accounting for needs in neighbouring regions, there is a bulk system need to reinforce the 230kV corridor between Lambton and Chatham. There are a number of large scale combined-cycle gas plants in the Sarnia-Lambton area and gas-fired generation output could vary depending on broader system conditions such as expected load growth in the province or availability of other generation resources. Moreover, as previously noted in Section 3.1, the Chatham-Kent/Lambton/Sarnia Region is connected to the US market through interconnections in Sarnia and Lambton. Import and export generation levels on the interties have a significant impact on the bulk transmission system. Recognizing gas-fired generation output and import/export levels are important parameters for the bulk system performance for this Region and given the needs in neighbouring regions, the IESO undertook a study to assess the bulk system adequacy under different system conditions. As a result, the need to reinforce the Lambton-by-Chatham corridor was identified.

6.4 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment and development initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables.

During the previous Regional Planning cycle, Wanstead TS was refurbished with 50/66/83MVA transformers, and its supply was upgraded from a single 115kV connection to a double 230kV connection. The station was placed in service at the end of 2018.

End-of-life refurbishment work was also completed on certain components at Chatham SS which included a new capacitor along with its associated breaker. This work was completed in 2020.

The following sustainment plans do not affect the results of this Needs Assessment study, but are included for completeness:

- The existing Lambton TS will be undergoing end-of-life asset replacements that include interconnection transformers T7/T8, DESN transformers T5/T6, and the 27.6kV switchyard, and is scheduled to be completed in 2023.
- The existing Scott TS will be refurbished – autotransformer T5 will be replaced like-for-like with a 250MVA unit and the 115kV switchyard will be rebuilt. This refurbishment is scheduled to be completed in 2024.
- The existing St Andrews TS will be refurbished with standard 50/66/83 MVA transformers and is scheduled to be completed in 2025. This refurbishment will result in station capacity increase of approximately 20 MVA.
- The existing Kent TS T1/T2 DESN will be refurbished and will include the replacement of T2 and the 27.6kV switchyard. T1 was replaced on demand due to a transformer failure in 2020. The refurbishment is scheduled to be completed in 2027. As a result of this refurbishment, the station capacity will increase by 35-40 MVA.

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team agrees that Scoping Assessment is required at this time.

To address the high demand for capacity due to new customer connection requests at Wallaceburg TS, further regional planning is required to coordinate the connection of a new supply station Dresden TS, which otherwise cannot be accommodated until after the IESO's recommended Lambton-to-Chatham reinforcement in 2028. This plan would eliminate the need for capacity at Wallaceburg TS which is also limited by its connection to a single 115 kV circuit and would provide a more reliable connection supplied by two 230kV circuits at the proposed Dresden TS.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

APPENDIX A: LOAD FORECASTS

As noted in Section 5, conservation and demand management (CDM) and distributed generation (DG) projects forecast information provided by the IESO were used to determine the net load forecast. The forecasted CDM achievement in the Chatham – Kent/ Lambton/Sarnia area is summarized in Table 3 and it represents the percentage reduction applied to gross peak demand at each station.

Table 3: CDM forecast for the Chatham- Kent/Lambton/Sarnia Region

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CDM	0.64%	1.76%	2.73%	3.44%	3.95%	4.15%	4.30%	4.30%	4.30%	4.30%

The net forecast in Table 5 and Table 6 reflects the impact of all existing DG on the area's coincident peak demand. No additional contracted resources are currently forecast to come into service during the study period.

Table 4: Chatham-Kent/Lambton/Sarnia regional net coincidental load forecast

Regional Summer Coincident Peak

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	15.00	15.56	15.63	20.28	20.39	20.52	20.71	20.93	21.16	21.39	21.61
Forest Jura DS	18.8*	19.82	20.00	20.09	20.22	20.40	20.63	20.91	21.22	21.55	21.89	22.24
Kent TS (T1/T2)	155.6**	88.60	89.63	94.23	91.46	91.71	96.05	98.07	98.90	99.85	100.80	101.74
Kent TS (T3/T4)	59.8	41.83	42.10	42.18	42.33	42.59	42.94	43.42	43.93	44.50	45.08	45.67
Lambton TS	103.8***	58.25	58.32	58.13	58.03	58.07	58.23	58.56	58.93	59.39	59.84	60.30
Modeland TS	196.5	98.97	102.38	108.27	114.31	120.60	127.07	130.13	133.23	136.48	139.73	142.97
St. Andrews TS	101.8****	60.67	63.49	63.30	63.19	90.55	90.71	91.06	91.43	91.90	92.36	92.82
Wallaceburg TS	51.8	33.91	34.04	34.16	34.37	34.46	34.59	34.86	35.17	35.52	35.85	36.15
Wanstead TS	118.9	39.25	40.45	40.99	41.62	42.20	49.54	50.41	51.33	52.30	53.25	54.18
CTS #1	N/A	26.67	26.90	27.14	27.37	27.61	27.85	28.10	28.34	28.59	28.84	29.09
CTS #2	N/A	17.80	18.01	18.22	18.43	18.65	18.86	19.09	19.31	19.53	19.76	19.99
CTS #3	N/A	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16	34.16
CTS #4	N/A	44.34	44.63	44.92	45.22	45.51	45.81	46.11	46.41	46.71	47.02	47.32
CTS #5	N/A	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53	8.53
CTS #6	N/A	2.69	2.71	2.73	2.75	2.77	2.79	2.81	2.83	2.85	2.87	2.89
CTS #7	N/A	53.79	54.19	54.59	54.99	55.40	55.81	56.22	56.64	57.06	57.48	57.90
CTS #8	N/A	29.57	79.73	80.62	81.57	82.08	82.54	83.07	83.68	84.25	84.80	85.27
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* Assuming cooling not available. With cooling LTR is 31.25 MVA.

** LTR will increase to approximately 195 MVA after T2 is replaced (2027)

*** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)

**** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table 5 : Chatham-Kent/Lambton/Sarnia regional net non-coincidental load forecast

Regional Summer Non-Coincident Peak

Station	Limited-Time Rating (MVA)	Historical (MW)	Forecast (MW)									
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Duart TS	200	17.52	18.17	18.25	23.69	23.81	23.96	24.19	24.44	24.72	24.98	25.23
Forest Jura DS	18.8*	26.60	26.84	26.97	27.14	27.38	27.68	28.07	28.47	28.92	29.38	29.85
Kent TS (T1/T2)	155.6**	105.10	106.31	111.78	108.49	108.78	113.94	116.33	117.31	118.45	119.57	120.68
Kent TS (T3/T4)	59.8	46.81	47.11	47.21	47.37	47.67	48.05	48.59	49.16	49.80	50.45	51.11
Lambton TS	103.8***	65.41	65.50	65.28	65.16	65.21	65.39	65.77	66.18	66.69	67.20	67.72
Modeland TS	196.5	114.81	118.76	125.59	132.60	139.89	147.40	150.94	154.54	158.31	162.08	165.84
St. Andrews TS	101.8****	65.06	68.08	67.88	67.77	97.10	97.28	97.65	98.05	98.55	99.04	99.54
Wallaceburg TS	51.8	39.11	39.26	39.41	39.65	39.75	39.91	40.21	40.56	40.97	41.35	41.70
Wanstead TS	118.9	46.42	47.84	48.49	49.23	49.91	58.60	59.63	60.71	61.86	62.98	64.09
CTS #1	N/A	32.20	32.48	32.76	33.05	33.34	33.63	33.92	34.22	34.51	34.82	35.12
CTS #2	N/A	19.35	19.57	19.80	20.03	20.27	20.51	20.75	20.99	21.23	21.48	21.73
CTS #3	N/A	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75	35.75
CTS #4	N/A	48.71	49.02	49.34	49.67	49.99	50.32	50.64	50.98	51.31	51.64	51.98
CTS #5	N/A	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96	9.96
CTS #6	N/A	2.77	2.79	2.81	2.83	2.85	2.87	2.89	2.91	2.93	2.95	2.97
CTS #7	N/A	56.08	56.50	56.92	57.34	57.76	58.19	58.62	59.05	59.49	59.93	60.37
CTS #8	N/A	112.89	113.74	114.59	115.45	116.32	117.19	118.07	118.96	119.85	120.75	121.66
CTS #9	N/A	0.00	1.00	10.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

* Assuming cooling not available. With cooling LTR is 31.25 MVA.

** LTR will increase to approximately 195 MVA after T2 is replaced (2027)

*** LTR will increase to approximately 120 MVA after T5/T6 are replaced (2023)

**** LTR will increase to approximately 120 MVA after T1/T2 are replaced (2025)

Table 6. Dresden TS Net Summer Non-Coincident Forecast

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load (MW)	33.45	45	43	56.3	59	59	59	59	59

Table 7. Dresden TS Net Winter Non-Coincident Forecast

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load (MW)	50.6	60.6	80.6	109.6	128.6	128.6	128.6	128.6	128.6

APPENDIX B: KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity
The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.

Coincident Peak Load
The electricity demand at individual facilities at the same point in time when the total demand of the region or system is at its maximum.

Contingency
The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM)
Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers’ use of electricity.

Distributed Generation (DG)
Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load
Amount of electricity that must be generated to meet all customers’ needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR)
A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast
Prediction of the load or demand customers will make on the electricity system

Net Load
Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load

The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load

The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Weather Corrected Data

Load data that is adjusted to account for extreme weather conditions using an adjustment factor.

APPENDIX C: ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Appendix D

CKLS Scoping Assessment Outcome Report

Chatham-Kent/Lambton/Sarnia Region Scoping Assessment Outcome Report

December 30, 2021

Connecting Today.
Powering Tomorrow.

Table of Contents

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the regional planning process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of the regional planning process for the Chatham-Kent/Lambton/Sarnia region was completed in June 2017. The Needs Assessment is the first step in the regional planning process and was completed in June 2016, which identified one need at Kent TS, but that no further regional coordination was required. Subsequently, both the Regional Infrastructure Plan (RIP) and Local Planning Report (June 2017) concluded that there was sufficient transfer capability on the distribution system to alleviate the Kent TS transformer and so no further action was needed.

The new cycle of the regional planning process for the Chatham-Kent/Lambton/Sarnia region started in August 2021. The Study Team led by Hydro One Transmission finalized the Needs Assessment on September 30, 2021, which identified some needs that may require further regional coordination. A Scoping Assessment was then undertaken by the Study Team, led by the IESO, that reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an Integrated Regional Resource Plan (IRRP) – where both wires and non-wires options have potential to address needs; a Regional Infrastructure Plan (RIP) – which considers wires-only options; or a Local Plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment Report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP and/or wires planning, if required; and
- Establishes the composition of the Technical Working Group, if required.

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Bluewater Power Inc.
- Entegrus
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator (IESO)

3. Categories of Needs, Analysis, and Results

3.1 Overview of the Region

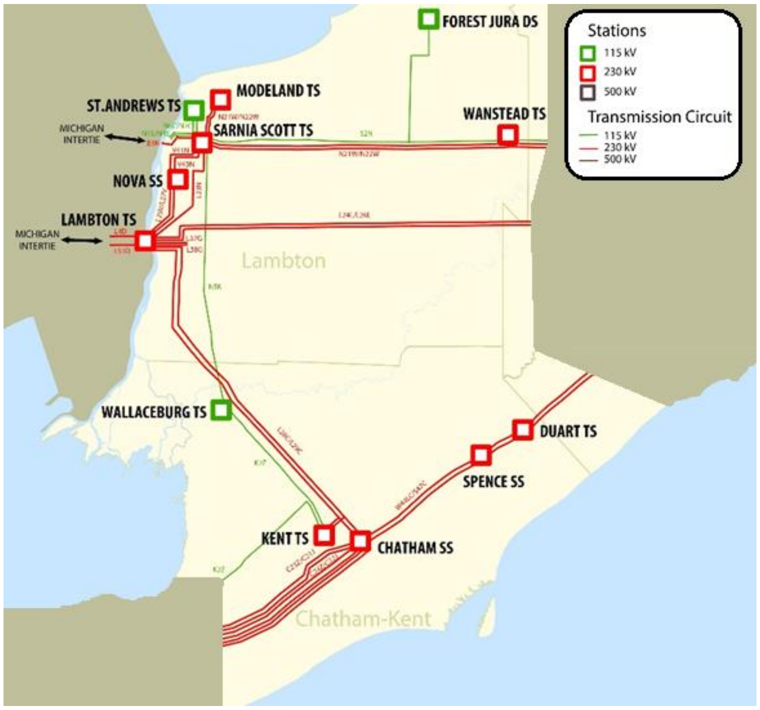
The Chatham-Kent/Lambton/Sarnia region is located west of the City of London and east of Essex County, and includes the municipalities of Lambton Shores and Chatham-Kent, as well as the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. Portions of Huron County (Municipality of South Huron) and Elgin County (Municipality of West Elgin) are also included in the region. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

This region also has a number of First Nations and Métis Nation of Ontario (MNO) councils, including:

- Indigenous communities including Aamjiwnaang First Nation, Bkejwanong (Walpole Island) First Nation, Caldwell First Nation, Chippewas of Kettle and Stony Point, Chippewas of the Thames First Nation, Mississaugas of the Credit, Moravian of the Thames, Nawash First Nation, Saugeen First Nation and Six Nations of the Grand River (Elected Council and Haundenosaunee Confederacy Chiefs Council/ Haundenosaunee Development Institute); and
- Métis Nation of Ontario communities including MNO Thames Bluewater Métis Council (London) and MNO Windsor-Essex-Kent Métis Council.

An overview of the Chatham-Kent/Lambton/Sarnia region and the location of the electrical infrastructure is shown in Figure 3-1. This region is summer-peaking (i.e., electricity demand is highest during the summer months), however forecast agricultural load growth in the Municipality of Chatham-Kent is winter-peaking.

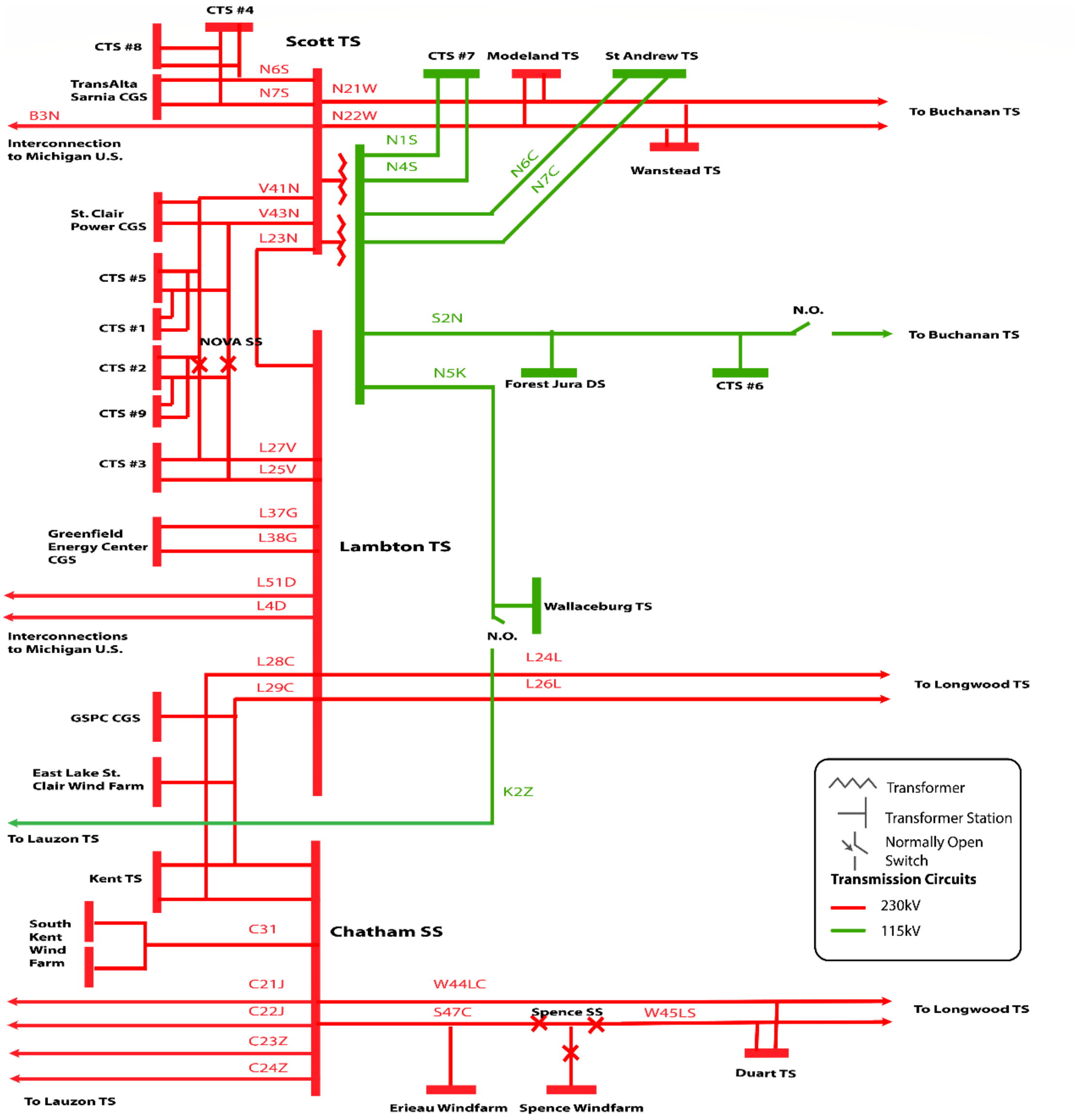
Figure 3-1 | Overview of the Chatham-Kent/Lambton/Sarnia Region



The region is currently supplied from a network of 115 kV and 230 kV transmission lines and stations, from the western edge of the City of London, to the City of Sarnia in the northwest, and the Municipality of Chatham-Kent in the southwest. The bulk of supply is transmitted from the 230 kV circuits between Lambton TS, Scott TS, and Chatham SS in the area, connected to the broader provincial system through Longwood TS and Buchanan TS in the east (N21W, N22W, L24L, L26L, W44LC and W45LS). It is also connected to the Windsor-Essex region in the west through 230 kV circuits at Chatham. There is a significant amount of supply resources in Sarnia-Lambton, strategically located near the Dawn gas supply hub, as well as three of the four interconnections between Ontario and Michigan (B3N, L4D and L51D). This area also includes large petro-chemical industrial loads in Sarnia-Lambton, much of which are interdependent with the combined heat and power generators.

An overview of the electrical infrastructure that currently supplies the region is provided in the single line diagram in Figure 3-2.

Figure 3-2 | Electricity Infrastructure in the Chatham-Kent/Lambton/Sarnia Region



The following transmission infrastructure falls within this region’s boundaries:

- 115 kV Transformer stations: St. Andrews TS, Wallaceburg TS, Forest Jura DS.
- 115/230 kV Transformer stations: Scott TS.
- 230 kV Transformer or Switching stations: Lambton TS, Duart TS, Modeland TS, Wanstead TS, Kent TS, Chatham SS.
- 9 customer-owned stations.

- 115 kV transmission circuits: N1S/N4S, N6C/N7C, S2N, N5K, K2Z.[1]
- 230 kV transmission circuits: N6S/N7S, V41N, V43N, L23N, L25V, L27V, L37G, L38G, L28C, L29C, C31, W44LC, W45LS, S47C, L24L, L26L, N21W, N22W.

3.2 Background of the Previous Planning Process

The regional planning process was formalized by the OEB in August 2013. To prioritize and manage the process, Ontario was organized into 21 regions based on electricity infrastructure boundaries; each of which were assigned to one of three groups based on urgency of need, where Group 1 Regions were being reviewed first. The Chatham-Kent/Lambton/Sarnia region was part of the Group 3 planning regions.

In June 2016, Hydro One Transmission published the first Needs Assessment report for the Chatham-Kent/Lambton/Sarnia region. The scope of the report included a review of system capability, reliability assessments, and asset sustainment timelines for the region. The report identified one need that did not require further regional coordination, a transformer capacity need at Kent TS. In June 2017, Hydro One Transmission published a Local Planning Report, with the Regional Infrastructure Plan (RIP) subsequently finalized in August 2017, which concluded that there was sufficient transfer capability on the distribution system to alleviate the Kent TS transformer and so no further action was required.

This current, second regional planning cycle started with the Needs Assessment report published by Hydro One Transmission in September 2021. The needs identified in the Needs Assessment report form the basis of the analysis for this Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

Hydro One Transmission's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. Furthermore, it identified new needs in the Chatham-Kent/Lambton/Sarnia region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation, summarized in Table 3-1 below. These projects provide a basis for future assessments and should be accounted for in this planning cycle.

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[1] Note, this circuit is also part of the Windsor-Essex region.

Table 3-1 | Needs Identified in the Previous Cycle and Implementation Plan Update

Need	Solution and Timing
Thermal overload on Kent TS transformer T3, for the loss of T4	No further action; sufficient transfer capability on the distribution system to alleviate the Kent TS transformer
Wanstead TS	In 2018, Wanstead TS was refurbished with 50/66/83 MVA transformers, and its supply was upgraded from a single 115 kV connection to a double 230 kV connection
Chatham TS capacitor SC1	In 2020, end-of-life the capacitor SC1 and associated breaker were replaced

Between cycles, additional end-of-life activities were identified in the area. Table 3-2 below summarizes the activities and provides an update on the status of project implementation.

Table 3-2 | End-of-Life Needs Identified Between Cycles and Implementation Plans

Need	Solution and Timing
Kent TS transformer T1	In 2020, Kent TS T1 was replaced on demand due to transformer failure

3.3.2 Needs to be Addressed in the Current Planning Cycle

The Needs Assessment identified new or updated needs in the Chatham-Kent/Lambton/Sarnia region using the 10-year station-level non-coincident demand forecast provided by the local distribution companies (LDCs), updated end-of-life asset condition information from Hydro One Transmission, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. During the Scoping Assessment process, additional end-of-life needs were identified for various 115 kV and 230 kV circuits in the Sarnia-Lambton area. Table 3-3 below outlines these regional needs and their timing. The location of the capacity need is highlighted in Figure 3-3, the end-of-life needs can be identified by their station or circuit labels.

Table 3-3 | Updated Regional Needs Identified

Need #	Station/Circuit	Description of Need
1	Wallaceburg TS	Immediate summer and Winter station capacity need
2	Lambton TS interconnection transformers T7/T8	Lambton TS 600 MVA voltage regulating transformers T7/T8 will be replaced with a single 1,000 MVA series voltage regulating transformer in 2023
3	Lambton TS transformers T5/T6	Like-for-like replacement, to be completed in 2023
4	Scott TS transformer T5	Like-for-like replacement, to be completed in 2024
5	St Andrews TS transformers T3/T4	Like-for-similar replacement with 50/66/83 MVA transformers, to be completed in 2025
6	Kent TS transformer T2	Like-for-similar replacement with 50/66/83 MVA transformers, to be completed in 2027
7	N1S/N4S	Like-for-similar replacement of circuit section from Sarnia Scott TS to Vidal JCT, to be completed in 2027
8	N6S/N7S	Like-for-similar replacement of circuit section from Sarnia Scott TS to St Andrews, to be completed in 2027
9	S2N	Like-for-similar replacement of circuit section from Sarnia Scott TS to Adelaide JCT, to be completed in 2025
10	N5K	Like-for-similar replacement of circuit section from Sarnia Scott TS to Kent TS, to be completed in 2027
11	N21W/N22W	Like-for-similar replacement of circuit section from Sarnia Scott TS to Buchanan TS, to be completed in 2021

Figure 3-3 | Geographic Location of Capacity Need to be Addressed in the Current Planning Cycle

In 2019, Hydro One Distribution identified potential agricultural load growth in the Municipality of Chatham-Kent, specifically in the community of Dresden. A separate study team[2] was formed to evaluate the Dresden load connection requests. That study[3] found that the optimal location of a new supply station (referred to in this report as Dresden TS) would be in the vicinity of the existing Wallaceburg TS, connected to the Lambton-to-Chatham 230 kV corridor. At that time, it was identified that additional load connections would result in bulk transfer violations, and a recommendation was deferred until after the IESO's bulk plan for the area was finalized. On September 23, 2021, the IESO issued a bulk plan for the West of London area, Need for Bulk System

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[2] Led by the IESO, consisting of Entegrus and Hydro One Transmission and Distribution.

[3] Refer to Appendix 3 for the 2020 Dresden Supply Connection Study.

Reinforcements West of London[4], which recommended a Lambton-to-Chatham reinforcement to be in-service by 2028. Through the course of that plan, it was identified that a new station (Dresden TS) is required to accommodate the agricultural load growth in Chatham-Kent, connected to the recommended new Lambton-to-Chatham circuits. To facilitate load connections ahead of the bulk reinforcement in 2028, interim measures may be required such as generation dispatch, and remedial action schemes.

In addition, the Needs Assessment identified that St Andrews TS, Kent TS and Forest Jura DS are approaching station capacity. However, end-of-life sustainment projects are planned which will address the needs identified.

Furthermore, through targeted engagement, communities and stakeholders in the region have identified that there may be additional load growth in the broader region due to economic development, in particular in the Chatham and Sarnia-Lambton areas. This potential growth is mainly attributed to vehicle electrification, development of a hydrogen hub in Sarnia-Lambton, as well as residential and industrial growth. However, it was noted that details of the magnitude and timing of this growth are uncertain.

3.3.3 Analysis of Needs

The Study Team has discussed the needs in the Chatham-Kent/Lambton/Sarnia region and potential planning approaches to address them.

The station capacity need at Dresden is driven by forecast agricultural load growth, for which a wires option has been identified as required. Though the optimal connection for that supply station should be the proposed bulk reinforcement along the Lambton-to-Chatham corridor, this will not be in-service until 2028, so near-term measures will be needed to address the requested load connections starting in 2022. Since this has been assessed in recent studies including the West of London bulk plan and the Dresden Load Connection Study (included in Appendix 3), the results of which can be leveraged to explore interim solutions in parallel with the required supply station connection process in order to expedite this load.

There is limited capacity available at existing stations to accommodate the Dresden capacity need (129 MW need). There is the potential for up to 10 MW of capacity at Wallaceburg TS, which is the closest existing station. Kent TS is the next closest station, which may have up to 40 MW of available capacity in the near-term. However, depending on the location of the new loads, this may require buildout of distribution lines approximately 20 km in length to connect to Kent TS. Even with these distribution connections, an 80 MW capacity need remains, which will require a new supply station. While the connection lines for this station has been determined through previous studies, there may be opportunities to integrate this with the Lambton-to-Chatham lines underdevelopment, depending

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[4] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/WOL_Bulk_Report_Final_20210923.ashx

on the location and staging of that project. There may also be ways to temporarily connect loads to the existing infrastructure at a lower level of reliability. However, the ultimate connection of new loads in this area must be to the new Lambton-to-Chatham circuits to ensure reliable long-term supply to the new loads and maintain the required supply capacity to the Chatham-Kent and Windsor-Essex areas outlined in the West of London bulk study. Thus, further wires planning is required to finalise details of interim supply at a lower level of reliability and transition the ultimate connection to the new Lambton-to-Chatham lines underdevelopment. This would be best assessed through a Resource Infrastructure Plan, led by Hydro One Transmission, which would also more closely align assessment timelines with the capacity need date.

Aside from this capacity need, it may be premature to conduct comprehensive regional planning for the Sarnia-Lambton sub-region at this time, as the details of potential economic development plans are still in flux. However, there is value in exploring the effects of other local development projects once more information is finalized – whether they are related to specific industries, economic development plans (i.e., potential hydrogen hub in Sarnia-Lambton, greenhouse facilities[5]), or community energy plans and targets. Depending on when further details about these anticipated local developments are solidified, the Working Group will assess the value of leveraging the recently completed Needs Assessment and Scoping Assessment from this cycle or if enough time has passed to necessitate formally triggering the next cycle of planning early, as required.

Recommendation: The Dresden capacity need has been assessed in recent studies including the West of London bulk plan, the results of which can be leveraged to explore interim solutions in parallel with the required supply station connection process in order to expedite this load. Thus, wires planning through a RIP led by Hydro One Transmission is recommended to address the needs in the Chatham-Kent sub-region.[6]

Moreover, although there are no needs in the Sarnia-Lambton sub-region currently forecast to arise in the mid-term (5 to 10 years out), the Working Group will continue monitor growth in the region and re-evaluate these needs periodically, in order to trigger further regional planning for the Sarnia-Lambton sub-region as required.

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[5] The IESO commissioned the Greenhouse Energy Profile Study in 2019 to assess potential energy use in the indoor agriculture sector across five regions – of which Chatham-Kent was one.

[6] A Terms of Reference for the Chatham-Kent sub-region RIP is provided in Appendix 2. This will be incorporated into Hydro One Transmission's Terms of Reference for the Chatham-Kent/Lambton/Sarnia RIP.

4. Conclusion and Next Steps

The Scoping Assessment concludes that wires planning led by Hydro One Transmission is required to address the capacity need in the Chatham-Kent sub-region, through a Regional Infrastructure Plan. The Working Group will explore interim measures to expedite the Dresden load connections in parallel with wires development.

The Working Group will continue to monitor load growth in this region and re-evaluate these needs periodically, in order to trigger further assessments for the Sarnia-Lambton sub-region as required.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
EOL	End-of-Life, end of life
GIS	Gas Insulated Switchgear
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating

Acronym	**Definition**
MNO	Métis Nation of Ontario
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MVar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PSS\E	Power System Simulator for Engineering
RIP	Regional Infrastructure Plan
SC	Static Capacitor
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station

Appendix 2 – Regional Infrastructure Planning – Scope for Chatham-Kent Sub-Region

1. Introduction and Background

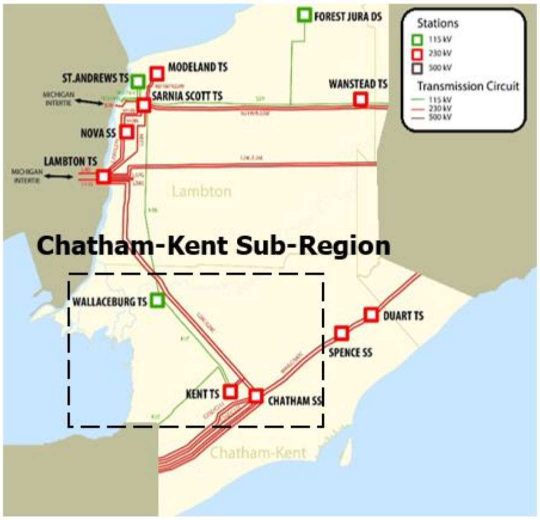
These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for the Chatham-Kent sub-region capacity needs. This will be incorporated into the broader Terms of Reference for the Chatham-Kent/ Lambton/Sarnia Region RIP, which will be subsequently developed by Hydro One Transmission.

Based on the forecast demand growth within this sub-region and limits on the capability of the transmission capacity supplying the area, and the urgent timelines for load connection requests, a regional infrastructure planning approach is recommended, with the results of recent studies including the West of London bulk plan, leveraged to explore interim solutions in parallel.

Chatham-Kent/Lambton/Sarnia Region

The Chatham-Kent sub-region is currently summer-peaking, however forecast agricultural load growth in the Dresden area will make the sub-region winter-peaking. It is primarily supplied by 230 kV circuits from Lambton TS in the north to Chatham SS (L28C and L29C) and from Longwood TS in the east to Chatham SS (W44LC/S47C and W45LS). The approximate geographical boundaries of the sub-region are shown in Figure A2-1.

Figure A2-1 | Overview of the Chatham-Kent/Lambton/Sarnia Region

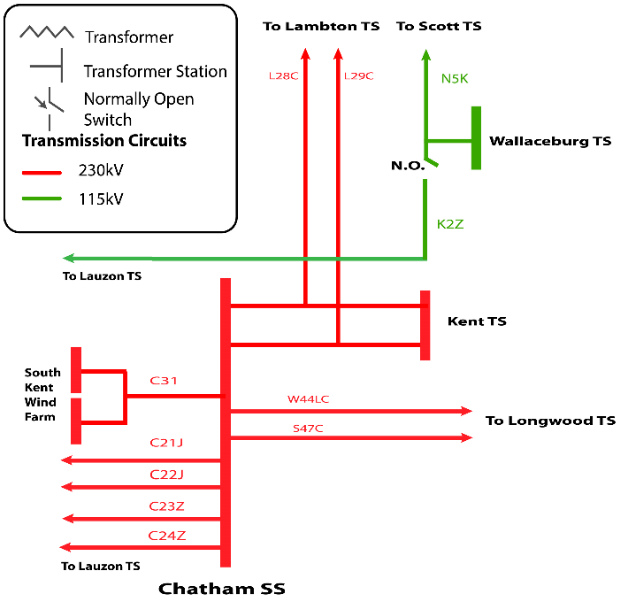


The region is located west of Eglin County and east of Essex County, and includes the municipality of Chatham-Kent. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Chatham-Kent Sub-Region Electricity System

The electricity system supplying the Chatham-Kent/Lambton/Sarnia region is shown in Figure A2-2.

Figure A2-2 | Chatham-Kent Sub-Region Electricity System



This RIP will address regional needs in the Chatham-Kent sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 115 kV Transformer stations: Wallaceburg TS
- 115/230 kV Transformer stations: Scott TS
- 230 kV Transformer stations: Lambton TS, Duart TS, Modeland TS, Wanstead TS,
- 9 customer-owned stations
- 115 kV transmission circuits: N5K, K2Z
- 230 kV transmission circuits: L28C, L29C, C31, W45LS, S47C/W44LC.

It will also consider the integration of regional needs with transmission reinforcements underdevelopment in the area, specifically the Lambton-to-Chatham double circuit 230 kV lines which are expected in-service by 2028.

2. Scope

As identified in the Scoping Assessment, Hydro One Transmission will lead a joint initiative involving Hydro One Distribution, Entegrus, and the IESO, to initiate and undertake the wires planning work for the Chatham-Kent sub-region. The scope of this study is to develop alternatives to address the 129 MW winter capacity need at Wallaceburg TS. Recently completed studies, including the 2021 West of London bulk plan,[7] determined that the optimal connection for a new supply station to address this capacity need should be along the Lambton-to-Chatham reinforcement currently under development. Since these circuits will not be in-service until 2028, so near-term measures will be needed to address the immediate load connection requests.

The RIP will explore ways to facilitate early connection of loads ahead of the Lambton-to-Chatham circuits in 2028, such as by temporarily connecting loads to the existing infrastructure at a lower level of reliability. However, the ultimate connection of new loads in this area must be to the new Lambton-to-Chatham circuits to ensure reliable long-term supply to the new loads and maintain the required supply capacity to the Chatham-Kent and Windsor-Essex areas outlined in the West of London bulk study.

The plan will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

The Chatham-Kent RIP will:

- Prepare a 10-year electricity demand forecast for the appropriate stations and reaffirm needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the Chatham-Kent sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices;
- Establish feasible wires alternatives to address the needs of the Chatham-Kent sub-region, which integrates these alternatives with supply from transmission reinforcements underdevelopment in the area, specifically the Lambton-to-Chatham double circuit 230 kV lines; and
- Develop a flexible and comprehensive wires plan for the Chatham-Kent sub-region.

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[7] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/WOL_Bulk_Report_Final_20210923.ashx

3. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- Hydro One Networks Inc. (Transmission) *(Team Lead for RIP)*
- Hydro One Networks Inc. (Distribution)
- Entegrus
- Independent Electricity System Operator

4. Activities, Timeline, and Primary Accountability

Activity	**Lead Responsibility**	**Deliverable(s)**	**Timeframe**
Trigger start of wires planning	Hydro One Transmission		Q1 2022
Review and reaffirm load forecast for Chatham-Kent sub-region	LDCs	Station-level annual load forecast for Chatham-Kent sub-region	Q1 2022
Review and reaffirm CDM and DG for study period	IESO		Q1 2022
Perform relevant system studies to identify supply capabilities	LDCs	Load transfer capabilities under normal and emergency conditions	Q1 2022
Perform relevant system studies to identify supply capabilities	Hydro One Transmission		Q1 2022
Develop options to address needs	Study Team	Develop flexible planning options for forecast	Q1 –Q2 2022
Technical comparison and evaluation	Study Team		Q2 2022
Complete Study Report	Hydro One Transmission	Regional Infrastructure Plan report	Q2 2022

Appendix 3 – Dresden Load Connection Study

Written: Feb 28, 2020[8]

1. Executive Summary

This study is intended to examine supply solutions to address the capacity need in the community of Dresden, in particular the 100 MW of firm load requests for 2021/2022. In addition to the firm load requests, 100-200 MW of load growth is projected within the next 3-5 years, based on anticipated demand from the recently completed Chatham-Kent Rural Pipeline Expansion. Consideration was given to solutions that could supply the total projected load.

This study is required to expedite supply for a near-term load requirement and to ensure that the connection point will not adversely affect the bulk transmission system. The next planning cycle is to commence in Q1 2020, however the schedule to complete a Needs Assessment and Integrated Regional Resource Plan (IRRP) would not meet the urgent timeline for the initial load requests. Further, recent load growth in the Kingsville-Leamington area have indicated a need for bulk reinforcements west of London. Given the location of this Dresden load, the connection point selected could impact the nature and timing of the bulk transmission reinforcement required.

The scope of this study was limited to Dresden load supply, in order to complete the following:

- Establish the load requirements in detail;
- Evaluate potential connection points; and
- Identify both local or bulk issues and benefits.

Analysis of available options was conducted based on providing:

- An economically feasible option for the customer(s) who would bear the costs;
- A viable timeline to meet the imminent capacity needs; and
- A system that leaves the bulk options open until a study can be completed to determine the most appropriate bulk reinforcement option.

Given the information at hand, the most feasible approach to address the Dresden load capacity need is to build a DESN station along the Lambton-to-Chatham corridor to supply the firm load growth. This option was selected for the following reasons:

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[8] Note, this study was completed prior to the start of the 2021 West of London bulk study and Chatham-Kent/Lambton/Sarnia regional planning. It is included here for reference, but results and conclusions do not reflect subsequent updates and recommendations.

- It is the minimum set of infrastructure that meets the firm capacity need with no stranded assets, regardless of the bulk reinforcement;
- It enables further load growth both in the Dresden area and the Chatham-Kent area; and
- It is the least-cost option that would enable customers to be connected promptly.

Concentrating near-term capacity expansion in the Wallaceburg and surrounding area serves the dual purpose of serving new load growth in the Dresden area, as well as alleviating capacity at Kent TS. This would facilitate further growth in the Chatham-Kent area, particularly in the Dresden area and south of Chatham proper where there have been indications of further growth. In addition, it does not preclude any bulk reinforcement option. However, prior to bulk reinforcement, any load additions to this path would require similar interim measures to the Kingsville-Leamington loads, with a corresponding lower level of reliability. This comes with an added risk to project timelines since the exemption approval required to implement interim measures is contingent on the completion of the west of London bulk plan to address these reliability concerns.

Critical to addressing this reliability concern will be establishing a bulk transmission reinforcement plan. A bulk study will be dependent on the Chatham-Kent/Lambton Sarnia region Needs Assessment to establish a forecast for the entire region. The Needs Assessment is scheduled for this year, and the bulk study for this region will by necessity occur in parallel.

Thus, there are two potential routes depending on the customer(s) level of risk tolerance:

- Proceed with the design and build work for a DESN on the L28C/L29C circuits, with the caveat that the final connection is contingent on the publication of a west of London bulk study and accompanying recommendation for addressing bulk system needs – Not recommended;
- Incorporate the connection of this load in the west of London bulk study and re-evaluate the connection of this load as part of regional planning - Recommended.

If a connection and corresponding System Impact Assessment (SIA) is pursued ahead of the bulk study and regional coordination, this would be subject to the following risks:

- Risk to load security, resulting from the interim measures.
- Risk to timelines, since the approval for the use of interim measures is contingent on the completion of a bulk reinforcement plan, which will take time to complete and coordinate with the Chatham-Kent/Lambton/Sarnia regional plan.
- Risk to approval of the use of interim measures, which also take into account any costs that may be imposed, as may be seen in the market solution to supply new loads in this thermally limited area. New loads would require similar interim measures and exemptions as loads currently connecting in the Leamington area.

2. Introduction

2.1 Purpose

The purpose of this Planning Study report is to document the results of power system analysis studies used to determine the planned performance of defined options to supply the near-term Dresden load forecast. The results of this Planning Study will be used in the development of needs and planning recommendations for the Chatham-Kent/Lambton/Sarnia Needs Assessment and Integrated Regional Resource Plan (IRRP), as well as the west of London bulk study.

2.3 Scope

This study is limited to identifying near-term wires-only options for the Dresden load growth. Given the urgent timelines for connecting the firm load, the scope of the study was limited to load connection options; not a complete regional study.

The results of this study will feed into the Chatham-Kent/Lambton/Sarnia regional planning, which may expand on this study and consider potential wires and/or non-wires options for the entire region.

The IRRP and bulk study for the Windsor-Essex region was completed in 2019, triggered primarily by the unprecedented load growth in the Kingsville-Leamington area. These studies indicated that there may be a need for bulk reinforcements west of London. The location of Dresden relative to transmission supply paths connecting to the Windsor-Essex region suggest that the connection point selected in this study could result in an impact to the nature and timing of bulk transmission reinforcement required. Therefore, bulk impacts and upstream limitations for each screened option are identified at a high-level in this study. However, a separate bulk study will examine further wires and/or non-wires options to address the bulk reinforcements required. The timing of that bulk study will depend on regional planning to develop a load forecast for the entire region.

For practical purposes, the forecast developed for this study is limited to the next 10 years, with emphasis on the next five years.

2.4 Load Connection Needs

The load forecast for this area was developed based on discussions with various stakeholders, including Hydro One Distribution, Entegrus, the Municipality of Chatham-Kent, Enbridge Gas, and Ontario Greenhouse Vegetable Growers.

The load forecast is comprised of two parts: (i) the firm load forecast based on load connection requests received, and (ii) projected load growth based on natural gas utilization for greenhouses.

Over the last year, Hydro One Distribution received two connection requests in the Dresden area for new and expanded greenhouse facilities. This amounts to approximately 100 MW of load growth by 2021/2022, which is the firm load forecast at this time.

In November 2019, Enbridge completed the construction of a new gas pipeline in the area; the Chatham-Kent Rural Pipeline Expansion. This pipeline which runs from Dover Centre east through Tupperville and Dresden, provides 30,000 m^3/hr of natural gas capacity, or the equivalent of 350 acres of greenhouses. Since the Municipality of Chatham-Kent indicated that there are no water or wastewater supply concerns that would delay the development of this area, the impact of natural gas utilization projections was incorporated into the projected near- to mid-term electricity demand forecasts. The projected load forecast is an additional 100-200 MW of growth.

During the Windsor-Essex IRRP, a near-term capacity need was identified in Chatham-Kent, which exceeded the capacity of Kent TS. Due to the urgency and proximity of the load to the Windsor-Essex region, this need was incorporated into the recently completed Windsor-Essex IRRP. As a result of economic influences, the recommended station build in the area was not implemented, however there still remains the potential for load growth.

To be prudent, the focus of this study will be to address the firm load forecast. Options will be evaluated to ensure that capacity for future growth is enabled and investments are not stranded. As such, when connection requests are received the next stage of distribution or transmission investment can be easily triggered.

3. Study Methodology

To determine the feasible set of options, the following methodology was used:

- Options specification: A comprehensive set of wires only options to supply the Dresden capacity need was developed in collaboration with Hydro One Transmission, Hydro One Distribution, and Entegrus.
- Options screening: A preliminary assessment was conducted to prioritize the list of options, prior to a full technical assessment. This included high-level time and cost estimates to screen options that could not meet the need timeframe or were prohibitively expensive for the customer(s). Conservation areas and land impacted by First Nation treaties or reserves were considered when determining the feasibility of the options. Options that were electrically similar were combined into a single option, to expedite the technical assessment.
- Technical assessment: An analysis of the regional and bulk system impact of the prioritized set of options was performed, including conducting thermal and voltage analyses based on the scenarios and assumptions outlined in the next section.

4. Scenarios and Assumptions

4.1 Scenarios Assessed

The following scenarios were selected for analysis to establish the performance of the identified options relative to recognized planning standards and criteria as referenced in section 4.4.

Table A3-1 | Description of Credible Scenarios

Scenario Name	Scenario Type	Scenario Description
Scenario 1	Winter peak, low load growth, median generation, no intertie transfer on J5D, no local generation	Winter peak low scenario
Scenario 2	Winter peak, high load growth, median generation, no intertie transfer on J5D, no local generation	Winter peak high scenario

A summer case was considered but it was determined that peak demands and the most limiting contingency for this study occur during the winter. Refer to section 4.3.2 for details on the load forecasts.

4.2 Options Assessed

The following potential options were selected for analysis relative to the scenarios in section 4.1.

Table A3-2: Description of Options

Option	Scenario Description
Option 1	Supply from a new DESN station directly connected to the Chatham x Lambton 230 kV circuits (L28C/L29C)
Option 2	Supply from a 230-kV double circuit tap connection to a new DESN station at Dresden via the 230-kV transmission lines L28C/L29C from Lambton TS to Chatham SS
Option 3	Supply from a 230-kV double circuit tap connection to a new DESN station at Dresden via the 230-kV double circuit transmission lines L24L/L26L from Longwood TS to Lambton TS
Option 4	Supply from a 230-kV double circuit tap connection to a new DESN station at Dresden via the 230-kV transmission lines W44LC/S47C from Buchanan TS/Spence SS to Chatham SS

Option	Scenario Description
Option 5	Supply from a new double circuit tap connection to a new DESN station at Dresden from Chatham SS
Option 6	Supply from a new double 230 kV circuit from Lambton TS to new DESN station at Dresden to Chatham SS
Option 7	Supply to a new DESN station at Dresden from N5K circuit from Sarnia TS to Wallaceburg TS converted from 115 kV to a 230 kV circuit
Option 8	Supply from upsized transformers at Wallaceburg TS
Option 9	Supply from Duart TS through distribution feeders

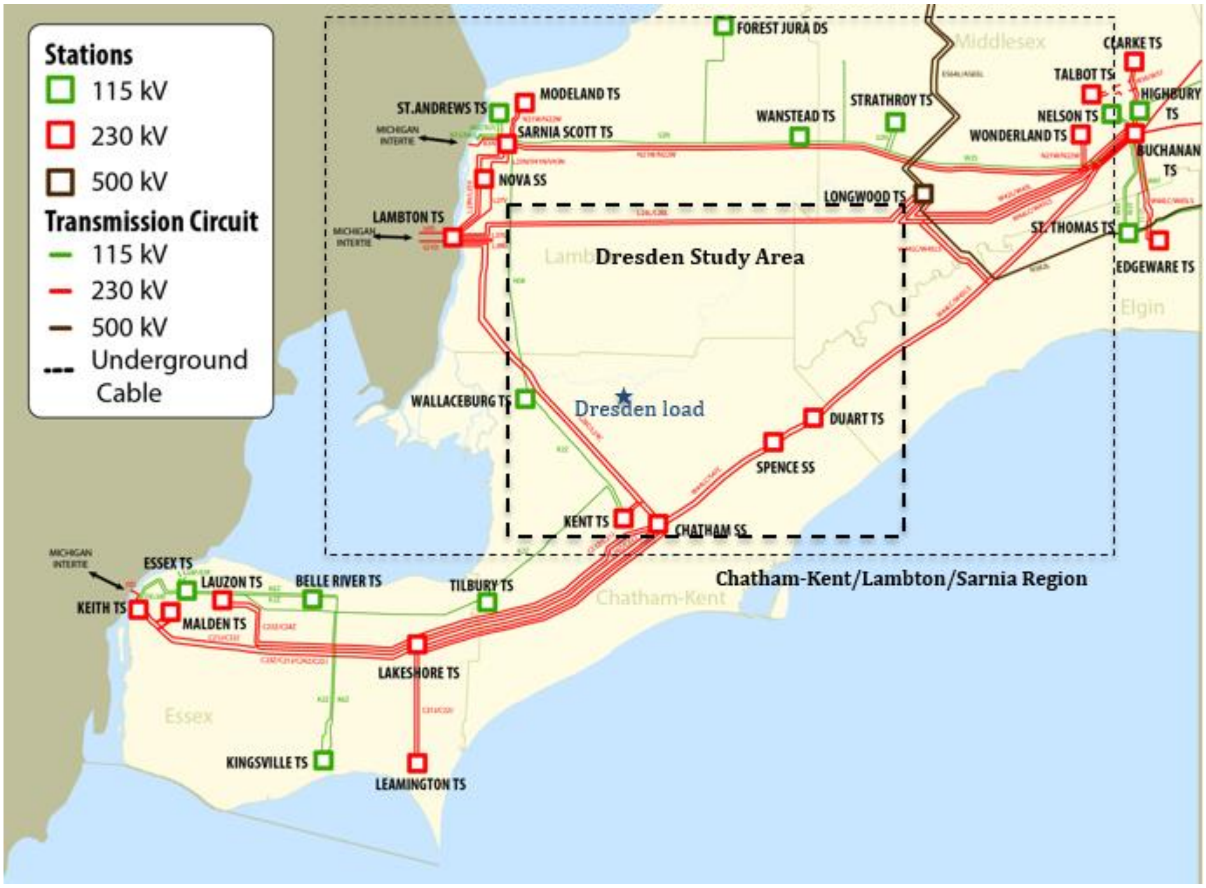
4.3 Study Area Assumptions

4.3.1 Study Area Transmission Configuration

The community of Dresden area is within the Chatham-Kent/Lambton/Sarnia region, which includes the municipality of Chatham-Kent, as well as the townships of Dawn-Euphemia, Enniskillen, St. Clair, and Villages of Oil Springs. The area is bordered by the city of London to the east, Windsor-Essex to the south west, and the remainder of the Chatham-Kent/Lambton/Sarnia region to the north.

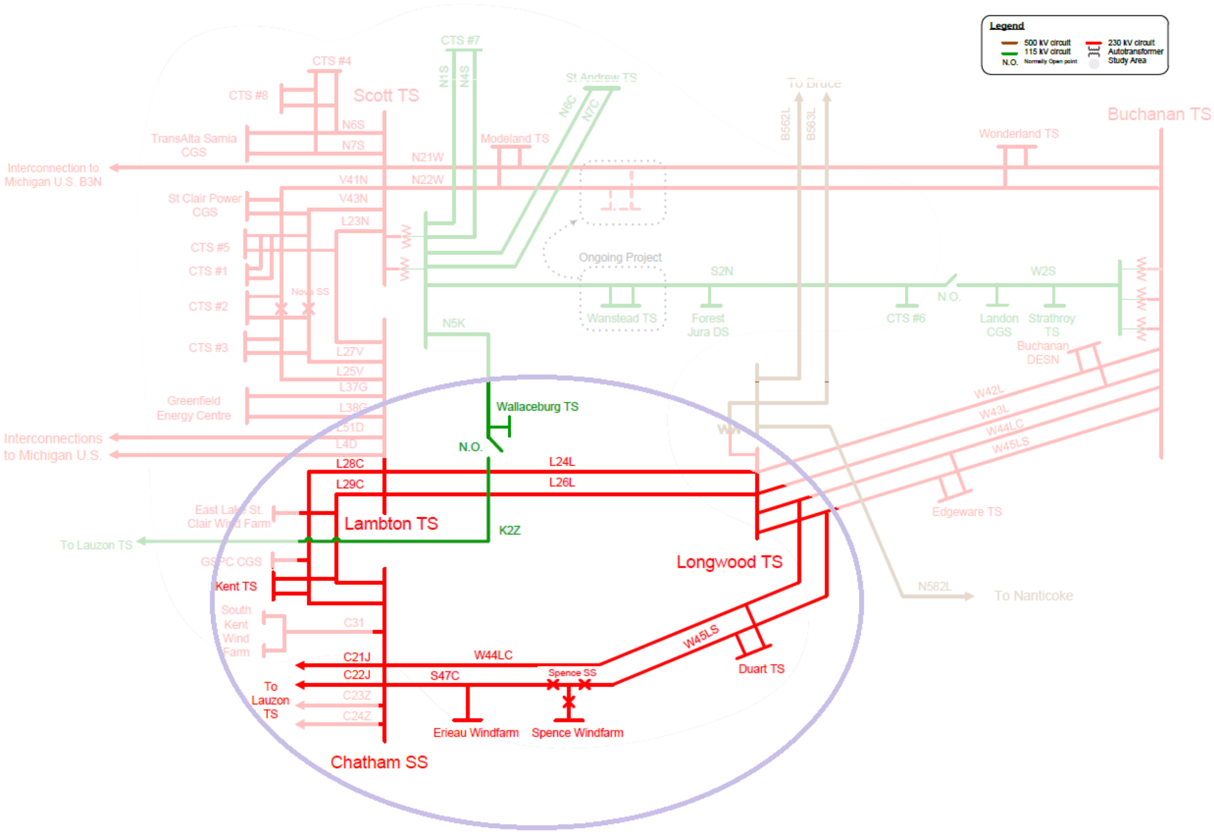
The approximate geographical boundaries of the sub-region are shown in Figure A3-1 within the broader Chatham-Kent/Lambton/Sarnia region and southwestern Ontario.

Figure A3-1: The Dresden Study area and Chatham-Kent/Lambton/Sarnia Region



This study focused on the Dresden electrical area, which includes the load and generation connected to circuits L24L, L26L, L29C, L28C, W44LC, and S47C, as illustrated in Figure A3-2.

Figure A3-2: Single Line Diagram of Electricity System Supplying the Dresden Study Area



4.3.2 Study Area Load

The closest existing supply station to Dresden is Wallaceburg TS, where there is 14 MW of capacity remaining, partially fulfilling the connection requests received by Hydro One Distribution. Options were considered to meet load forecast requirements, less the remaining Wallaceburg TS capacity.

The load for the study area is based on the following assumptions:

- 100 MW of connection requests within the study area to form the firm near-term study area load by 2022;
- Greenhouse utilization of Chatham-Kent gas pipeline capacity form the projected mid-term study area load from 2022-2030. Low and high forecasts were developed based on vegetable and cannabis greenhouse load respectively;
- Supply for 1,000 MW of load growth west of Chatham, this includes the Leamington DESN loads, transmission-connected customers at Leamington, and Lakeshore DESN loads (approximately equivalent to a 1,500 MW West of Chatham transfer); and

- A power factor of 0.95 is assumed for new greenhouse loads at Leamington, Lakeshore and Dresden based on historic performance.

Study area loads for each scenario described in section 4.1 are detailed in Tables A3-3 and A3-4 below.

Table A3-1: Study Area Loads (MW) – Scenario 1*

Station	Year 0	Year 2	Year 4	Year 6	Year 8	Year 10
Wallaceburg TS	41.4	141.1	172.0	233.5	249.2	249.3
Kent TS	137.2	137.7	138.1	138.6	139.0	139.2

Table A3-2: Study Area Loads (MW) – Scenario 2*

Station	Year 0	Year 2	Year 4	Year 6	Year 8	Year 10
Wallaceburg TS	41.4	141.1	202.7	325.6	341.3	341.4
Kent TS	137.2	137.7	138.1	138.6	139.0	139.2

*Red values indicate that the loading exceeds the existing station capacity

4.3.3 Study Area Generation

Ontario resources within the Chatham-Kent/Lambton/Sarnia region consist of over 2,500 MW of installed gas generation in Sarnia-Lambton, and approximately 440 MW of renewable resources.

Additional injections into the area can come from the following interties between Ontario and Michigan:

- L4D/L51D from St. Clair County, Michigan via Lambton TS in Lambton County, Ontario;
- B3N from St. Clair County, Michigan via Scott TS in Lambton County, Ontario; and
- J5D from Detroit, Michigan via Keith TS in Windsor, Ontario.

Supply for the study area was based on the following assumptions:

- Median winter on peak generation supply for top 10 percentile of load hours;
- No intertie exchange on J5D;
- Median intertie exchange on B3N, L4D, and L51D; and
- No post-contingency intertie control.

4.3.4 Study Area Automatic Switching, Special Protection Systems, and Remedial Action Schemes – Windsor Area Overload Protection and Load Rejection Scheme

Table A3-5: Study Area Automatic Switching, Special Protection Systems, and Remedial Action Schemes – Windsor Area Overload Protection and Load Rejection Scheme

Event	Action
Events that result in the loss of one or two of the 230 kV circuits /transformers at Lauzon TS	Reject loads at Kingsville TS, Belle River, Tilbury West and/or capacitors at Kingsville, Lauzon
Events that result in the loss of one or two of select 115 kV circuits and capacitors from Keith TS and Lauzon TS	Reject loads at Kingsville TS, Belle River, Tilbury West and/or capacitors at Kingsville
Supply to circuits K2Z/K6Z both decline to a voltage level of 106 kV or less	Reject the loads at Kingsville TS
Events that result in the loss of one or two of select 115 kV or 230 kV circuits from Keith TS	Reject generation at Brighton Beach, East Windsor, Keith autotransformers, loads at Keith, and/or capacitors at Keith, or select capacitors at Essex

Table A3-6: Study Area Automatic Switching, Special Protection Systems, and Remedial Action Schemes – Leamington Load Rejection Scheme

Event	Action
Events that result in the loss of one or two of the 230 kV circuits west from Chatham SS or Brighton Beach generation	Reject loads at Leamington TS and/or loads directly connected to the tap line to Leamington TS
Events that result in sustained low voltages at Leamington TS and/or loads directly connected to the tap line to Leamington TS	Reject loads at Leamington TS and/or loads directly connected to the tap line to Leamington TS
Events that result in sustained over-voltages at Leamington TS and/or loads directly connected to the tap line to Leamington TS	Trip capacitors at Leamington TS and/or reject the loads directly connected to the tap line to Leamington TS

4.4 Planning Criteria

This study applies planning criteria in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation (“NERC”) TPL-001 “Transmission System Planning Performance Requirements” (“TPL-001”),
- Northeast Power Coordinating Council (“NPCC”) Regional Reliability Reference Directory #1 “Design and Operation of the Bulk Power System (“Directory #1”), and
- IESO Ontario Resource and Transmission Assessment Criteria (“ORTAC”).

5. Study Results

5.1 Options Screening

The following table summarizes the option screening analysis. A detailed analysis is provided in the subsequent subsections.

Options were considered to supply the Dresden load, after exhausting all the available capacity on the current system.

Table A3-7: Option Screening Summary

Option	Costs[9] ($M)	Timeframe [10] (years)	Load Enabled[11] (MW)	Other Benefits/ Ramifications	Proceed to Technical Assessment
Option 1	60	3-5	200	• Can serve nearby loads • Takes away from ability to supply Windsor-Essex loads; advances bulk reinforcement need	Yes
Option 2	70	6-8	200 (500)	• Electrically similar to Option 1	No
Option 3	110	6-8	200 (500)	• Furthest supply point from load	No
Option 4	95	6-8	200 (500)	• Some existing capacity available	Yes
Option 5	95	6-8	200 (500)	• Utilizes existing railway corridor	No
Option 6	180	6-8	200 (500)	• Utilizes existing railway corridor • Facilitates generation supply • Potential bulk system benefit	No
Option 7	125	5-7	200	• Utilized existing right-of-way • Circuit reaching end of life • Facilitates generation supply	No

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[9] Costs in Table A2-7 estimate both distribution and transmission costs to connect the load enabled (MW) amount specified. Values are in 2019 Canadian dollars.

[10] Time estimates are based on requirements for Environmental Approval, Section 92 approval, land acquisition, and recent estimates provided for projects in the area.

[11] The load enabled in brackets refers to the additional load that can be further enabled with an accompanying transmission and/or distribution cost, as applicable.

Option 8	75	5-7	To be determined	• Voltage, outage and GIS equipment limits	Yes
Option 9	120	3-5	200	• Voltage and reliability limits, river/rail/First Nation land crossing	No

5.1.1 Option 1: DESN on L28C/L29C

This would require a new DESN directly connected to the existing L28C/L29C circuits between Wallaceburg and Dover Centre Township to the south. Distribution feeders could be used to serve the dual purpose of connecting the Dresden loads, as well as providing an alternate supply for some northern loads currently fed from Kent TS. This second purpose would benefit the Chatham-Kent area more broadly, by relieving the fully loaded Kent TS and thus facilitating development south of Chatham proper. To that end, the DESN station may be sized to supply future growth with marginal incremental cost.

Load added to this path would take away from the ability to supply load in the Windsor-Essex region, since this path is thermally limited post-contingency. However, this option is the least-cost option that meets the timeline for the firm load increase within a reasonable timeframe. A technical assessment is required to determine the exact impact this option would have before a bulk reinforcement could be implemented.

5.1.2 Option 2: Tap onto L28C/L29C

This option is electrically similar to Option 1, since it has the same supply source and thus the same impact on the system’s ability to serve the Windsor-Essex loads. The primary difference between the two options is the approximately 10 km of a double 230-kV circuit tap connection from the station to the L28C/L29C circuits, where Option 1 would instead use distribution feeders between the station and the loads. The tap connection for this option would result in slightly higher costs and a longer execution timeline. Thus, Option 1 will be evaluated in lieu of this option.

5.1.3 Option 3: Tap onto L24L/L26L

This would require a 230-kV double circuit tap connection, of approximately 25 km from the existing L24L/L26L circuits to the Dresden area. This option would bypass the current bulk system concerns. However, it would require a significant expenditure to construct the long tap line, which would be approximately equivalent to a new circuit, without contributing towards a potential bulk solution. Since this option does not provide any additional system benefit, the total cost would have to be borne by the triggering customer(s). In addition, the timeline for this option does not meet the near-term timeframe for firm or projected load forecasts. Thus, this option was not considered for further assessment.

5.1.4 Option 4: Tap onto W44LC/S47C

There is some existing capacity available on this path, wherein more load can be added before having a detrimental impact on the bulk system, i.e. supply to Windsor-Essex. While this option is more expensive and does not meet the forecast timelines, for the purposes of limiting the bulk impact, a technical assessment is recommended to determine the amount of load that could be supplied and other impacts.

5.1.5 Option 5: New double circuit from Chatham SS to new Dresden DESN

This option is electrically similar to Option 1, since it would have the same impact on the bulk system, i.e. the ability to serve Windsor-Essex loads. There is an existing railway corridor between Chatham and Dresden, which could expedite the implementation of this option. However, this corridor would still need to be procured. Overall, Option 1 would be more cost-effective and faster to implement. Thus, this option was not considered for further assessment at this time.

5.1.6 Option 6: New double circuit from Chatham SS to Lambton TS

This would require a 230-kV double circuit, of approximately 50 km from Chatham SS to a new Dresden TS to Lambton TS. The cost for the tap connection and DESN would be approximately $180M. While this option might provide some system benefit by facilitating Lambton/Sarnia generation, it would necessitate that the west of London bulk reinforcement be along this corridor. The West of London bulk study is not far enough along to conclude that this reinforcement would be optimal for the region. In addition, the timeline does not meet the load projections even with the potential utilization of the existing railway corridor. Thus, this option was not considered for further assessment, however should be considered in the west of London bulk study.

5.1.7 Option 7: Tap onto converted N5K

This option would require four parts:

- The conversion of the existing 115 kV circuit N5K from Scott TS to Kent TS into a 230-kV circuit, for a length of approximately 60 km;
- A 230-kV tap connection, of approximately 1.5 km from the converted N5K to either the L28C or L29C circuit;
- The conversion of Wallaceburg TS from a 115 kV to a 230 kV station; and
- A new DESN station on the 230 kV circuits between Wallaceburg and Dover Centre Township.

In terms of the bulk impact, this would facilitate the flow of Sarnia/Scott generation to supply the growing greenhouse loads in Dresden and the Windsor-Essex region. This option would take advantage of the sustainment savings from replacing the N5K circuit, which is reaching end of life by 2025, and also expedite the timeline by utilizing the existing right of way. However, the transformers at Wallaceburg TS were replaced in 2014, which could result in stranded assets were they to be replaced in such quick succession. Overall, the timing and substantive costs for this option are prohibitive solely for a load connection solution and so this option was not considered for further assessment. However, this should be considered during the design and implementation of potential West of London bulk study recommendations.

5.1.8 Option 8: Upsized Wallaceburg TS

Since the existing capacity at Wallaceburg TS is fully committed, more capacity could be provided by upsizing the station transformers from 25/42 MVA to 50/83 MVA. The transformers at Wallaceburg TS were replaced in 2014, which could result in stranded assets were they to be replaced in such quick succession. However, Hydro One Transmission has the ability to repurpose the equipment elsewhere on the system. As a further measure, an interim scheme could be set up to fully utilize the transformer capacity with a lower level of reliability, by rejecting load above the transformer station capacity following a contingency.

Aside from the transformer upsizing, the following would also be required:

- Upgrades to the gas insulated switchgear (GIS) on the low voltage yard;
- Addition of low voltage capacitors;
- Reconductoring of N5K; and
- Expansion of the distribution system to connect the new loads.

Wallaceburg TS, being at the end of a single radial 115 kV circuit, is sensitive to low voltage concerns which would be the limiting factor for how much additional capacity would be feasible from this option. The potential capacity may be further limited by the minimum voltages required to be maintained during outage conditions, when Wallaceburg load is transferred to S2N, or Tilbury load is transferred to N5K. However, this is a low-cost solution with the closest timeline match, and so this option should be considered through a technical assessment.

5.1.9 Option 9: Supply from Duart TS

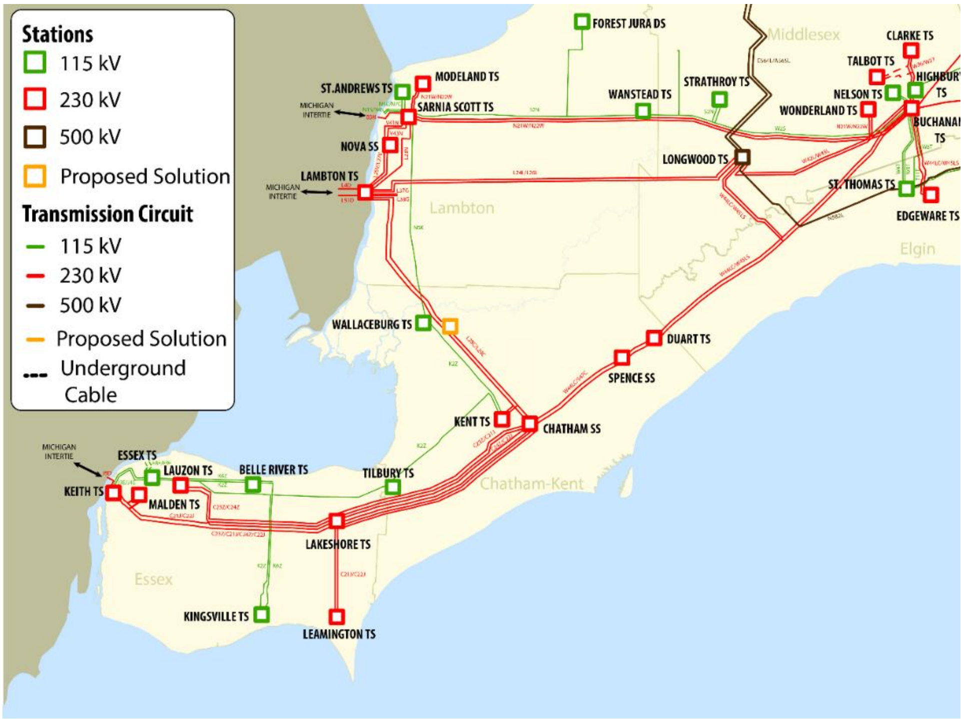
After Wallaceburg TS, Duart TS is the next closest supply station to the Dresden area. There is existing capacity at Duart TS which could be used to supply Dresden through approximately 40 km of distribution feeders. There are three main issues resulting from the long length of distribution feeders. Firstly, the loads would be subject to poor reliability, since the probability of customer interruptions is proportional to distribution length. Secondly, long feeders would result in low voltage concerns, requiring multiple voltage regulators and the expansion of the low voltage yard at Duart TS to compensate for this. Finally, the direct path from Duart TS to Dresden would go through rivers, railways and First Nations land, which would impact the route lengths, easements, and ability to secure right of ways. Based on the technical concerns and high cost, this option was not considered for further assessment.

5.2 Technical Assessment

5.2.1 Option 1: DESN on L28C/L29C

A representation of this option is depicted in Figure A3-3 below, location assumptions were made for study purposes, but if recommended the final design would be subject to standard approval processes.

Figure A3-3: Diagram of Option 1, DESN on L28C/L29C



A thermal assessment indicates that any additional loading on the L28C/L29C circuits would result in an almost 1:1 reduction in load served in the Windsor-Essex region. This would exacerbate the existing limiting contingency and the need for bulk reinforcement.

Currently, under the load projections for the Leamington area itself irrespective of the new Dresden loads, for an outage to either L28C or L29C, the next double contingency (W44LC/S47C) could overload the remaining circuit. In addition, under certain resource dispatch conditions with all elements in service, the loss of L28C or L29C would result in thermal overloads on the remaining LxC circuit. Any new loads added to the Dresden area with this option would exacerbate those issues. Thus, in order to facilitate the connection of load prior to a bulk reinforcement being in place, any new load added to this path would need to be rejected following a contingency. This interim scheme would result in a lower level of reliability. This would be in violation of ORTAC load security requirements, and thus a bulk reinforcement would be required to alleviate this violation, as well as an exemption until the reinforcement is in place. Given that the area is defined as part of the bulk power system, NPCC requirements prevent the scheme from being used with all elements in service. So a further exemption from NPCC would be required until a bulk reinforcement is in place. There is more risk involved in this process, given the larger group of stakeholders potentially affected. Both exemptions would be contingent on the publication of a bulk reinforcement plan. This would be the outcome of the west of London bulk study, which is targeted to be complete by the end of this year.

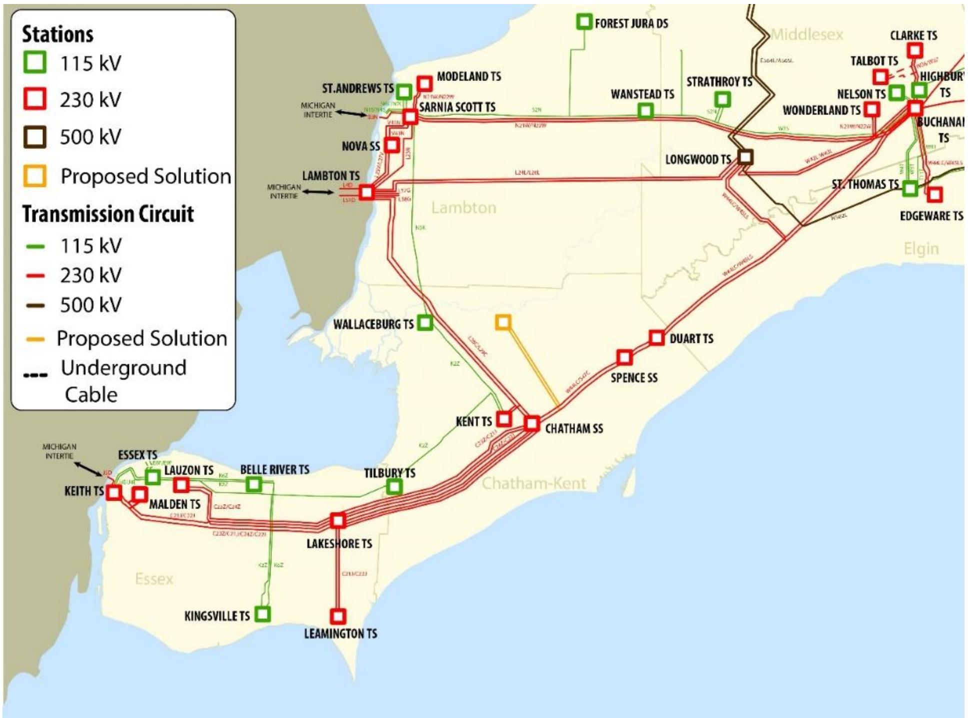
However, this is the least-cost option that would meet the firm load forecast within a reasonable timeframe. This option offers three main advantages. First, it requires the minimum set of infrastructure to meet the firm load forecast, with no stranded assets regardless of the ultimate bulk reinforcement. If further load projections are realized in the Dresden area, this investment could accommodate double the firm load forecast, and would not preclude any bulk reinforcements. Alternatively, if load growth were to fall short of projections this option would not result in stranded assets of tap lines or upgraded equipment, as would be the case with other options considered. Secondly, concentrating near-term capacity expansion in this area serves the dual purpose of serving new load growth in Dresden, as well as alleviating capacity at Kent TS. This would facilitate further growth in Chatham-Kent, particularly in Dresden and south of Chatham proper where there have been indications of further growth. Finally, this option is both the fastest and the least-cost solution that would enable customers to be connected promptly.

Overall, despite the interim lower level of reliability and risk of delay dependent on the bulk study, this option is technically feasible. Given the added benefits detailed above, it would be a reasonable solution.

5.2.2 Option 4: Tap onto W44LC/S47C

A representation of this option is depicted in Figure A3-4 below, location assumptions were made for study purposes, but if recommended the final design and routing would be subject to standard approval processes.

Figure A3-4: Diagram of Option 4, Tap onto W44LC/S47C



Currently, the most limiting contingency in the area is the loss of the W44LC/W45LS double contingency, which would cause the L28C/L29C circuits to exceed their short-term emergency ratings. The addition of load on W44LC/S47C would result in the new load being on a single supply from Chatham (on S47C) following the loss of W44LC/W45LS double contingency. This would add to the pre-existing L28C/L29C thermal limitation and offer no advantages to Option 1 and would require the added expense of building a new 20 km double 230 kV tap.

Given the additional cost and lead time, this option has no advantages to Option 1 and thus is not preferred.

Option 4 Variation A: Tap onto W44LC/W45LS with 230 kV tap Connection

In order to alleviate the issue identified above, the connection point along the corridor must be east of Spence SS so that the new station does not remain on single supply from Chatham TS after a W44LC/W45LS contingency. As long as the additional load on W44LC/W45LS does not result in the limiting contingency becoming thermal overloads on the W44LC/W45LS circuits for the loss of the L28C/L29C circuits, this option does exacerbate the bulk system limitation. A thermal assessment indicates that even with an additional 200 MW of load tapped on W44LC/W45LS plus Duart TS fully loaded to 200 MW, there were no post contingency thermal violations. Table A3-8 shows the post-contingency loading of the most stressed circuit sections following an L28C/L29C contingency.

Table A3-8: Thermal Assessment Results (L28C/L29C N-2 Post Contingency Loading)

Circuit Section	Loading [% of STE Rating]
W44LC Cowal Junction to Dresden Tap/Duart TS	93%
W45LS Cowal Junction to Dresden Tap/Duart TS	93%

Note that with this 200 MW additional load at Dresden supplied from a radial tap, post-contingency flow on J5D increased to approximately 360 MW eastward into Ontario, from the original 0 MW pre-contingency flow. This flow is approaching the J5D thermal limit; additional load connected to the W44LC/W45LS circuits above this level is not recommended.

There may also be local voltage issues at the end of the radial tap circuits depending on how much load is connected and the reactive compensation deployed. For example, Table A3-9 shows the post-contingency voltages at the new DESN located at the end of the radial tap following a L28C/L29C contingency. The study assumed a 21.6 MVar capacitor bank at both low voltage buses. The low voltage buses are very close to violating the 10% post-contingency voltage change criteria.

Table A3-9: New Dresden Area TS Post L28C/L29C N-2 Contingency Voltages

Bus	Pre-Cont. Voltage	Post Cont. Voltage	% Change	Max Post-Cont. Voltage	Min Post-Cont Voltage
High voltage Bus 1	233	214.7	8%	250	207
High voltage Bus 2	233	214.8	8%	250	207
Low voltage Bus 1	27.5	25.0	9%	30.9	24.3
Low voltage Bus 2	27.5	25.0	9%	30.9	24.3

This option would supply the new load without interim measures, resulting in a load security and restoration level consistent with the rest of the Ontario system. While this option would not have a detrimental impact on the bulk system, there is a significant cost and time associated with it. In addition, the investment in the tap connection would not serve as part of a bulk reinforcement solution since it does not connect to a central transmission hub, like Chatham SS. Thus, this is a feasible option, however the benefit of a reliable load connection at this stage (as opposed to post-bulk reinforcement) and risk of project delay dependent on the bulk study completion must be balanced with the cost to the customer.

Option 4 Variation B: Tap onto W44LC/W45LS with Distribution Connection

Another variation of this option would be to build a DESN directly on the W44LC/W45LS circuits at the location were the tap line in Variation A begins, i.e. east of Spence SS. Instead of the 230 kV tap connection, distribution feeders could be used to connect to the Dresden load. Duart TS is less than 10 km east of Spence SS and has available capacity currently at the station. Thus, to build another station between Spence SS and Duart TS is redundant. For reasons explained in Section 5.1.9, supplying the new load from Duart TS is not feasible.

5.2.3 Option 8: Upsized Wallaceburg TS

A steady state voltage assessment found that more than 60 MW load at Wallaceburg TS would result in a voltage depression at Wallaceburg TS. This is the equivalent of an additional 20 MW of load from the current station winter peak and equivalent to the current station winter capacity. Thus, no additional load can be enabled through this option beyond the existing capacity of the station that has been allocated to Hydro One Distribution. A summary of the post-contingency voltages is provided in Table A3-10.

Table A3-10: Voltage Assessment Study Results – All Elements In-service*

Bus	Loading [MW]	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Wallaceburg	41	119	127	113
Wallaceburg	50	117	127	113
Wallaceburg	60	113	127	113
Wallaceburg	70	111	127	113

*Red values indicate that the loading exceeds the existing station capacity

According to the current operating instructions, under a N5K outage condition a maximum of 30 MW of load can be maintained at Wallaceburg TS when supplied from K2Z. Similarly, when Tilbury West DS load is transferred to N5K the maximum allowable loading on N5K is 50 MW. Outages will need to be planned for off-peak timeframes when load is below this level, subject to a detailed assessment of the particular configuration at the time.

Option 8 Variation A: Autotransformers connecting N5K to Kent TS

Another variation of this option considered upsizing Wallaceburg TS and connecting the 115 kV circuit N5K to Kent TS through autotransformers. This would provide additional voltage support via Kent TS. Pre-contingency, the amount of load that could be added to this path is approximately 140 MW before hitting both the thermal limit of N5K and low voltage limit at Wallaceburg TS as show in Table A3-11. However, this configuration causes N5K to become a 115 kV parallel path to the L28C/L29C circuits. The L28C/L29C circuits are already the thermally limiting element for the West of Chatham transfer capability. Under a 1,500 MW West of Chatham flow condition, after the loss of W44LC/W45LS, N5K is thermally overloaded with only 30 MW of load at Wallaceburg TS, as shown in Table A3-12.

Table A3-11: Thermal and Voltage Study Results (Pre-Contingency)*

Bus	Loading [MW]	Voltage [kV]	N5K Thermal Loading [% Cont. Rating]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Wallaceburg	130	114.3	93%	127	113
Wallaceburg	135	113.8	96%	127	113
Wallaceburg	140	113.1	98%	127	113
Wallaceburg	145	112.6	100%	127	113

Table A3-12: Thermal and Voltage Study Results (Post W44LC/W45LS Contingency)*

Bus	Loading [MW]	Voltage [kV]	N5K Thermal Loading [% STE Rating]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Wallaceburg	30 MW	113.4	98%	127	113
Wallaceburg	35 MW	113.3	100%	127	113
Wallaceburg	40 MW	113.2	101%	127	113

*Red values indicate that the loading exceeds the existing station capacity

This variation increases the cost by $12M bringing the total cost of this option to $87M. Due to the thermal limitations created by the parallel 115 kV path, load supply beyond 40 MW is not possible. Thus, this variation is not feasible.

Option 8 Variation B: Additional Capacitors at Wallaceburg TS

In order to compensate for the low voltage concerns, another variation that was considered was the installation of a high voltage capacitor at Wallaceburg TS. Typical commercially available high voltage capacitors range from 96 – 210 MVar. Based on study results, switching in even a 50 MVar high voltage capacitor would violate the 4% steady state change criteria of the delivery point bus, as stipulated in ORTAC Sec 4.3. This would also exceed the upper voltage limit of the Wallaceburg low voltage bus. Thus the addition of a high voltage capacitor and an associated bus at Wallaceburg TS is not a feasible option.

An alternate would be to add low voltage capacitors at Wallaceburg TS. This would eliminate the reactive element switching change violation. It was found that the addition of every 10 MVar of reactive power would enable the supply of an additional 10 MW of load at Wallaceburg TS, with a corresponding $1.5M per capacitor.

However, there is a limit to the number of low voltage capacitors that can be added to Wallaceburg TS. The current station configuration of Wallaceburg has no available space for another element or bus and the station itself it surrounded by a road to the north, and residential houses and farmland in the other directions. The cost for land procurement, station expansion, and bus construction would further increase the cost and timeline of this option. Thus this option is not feasible.

6. Conclusions and Recommendations

In consultation with the transmitter and distributor, nine options were considered to supply the firm load forecast for Dresden. Feasibility screening of available options was conducted based on providing:

- An economically feasible option for the customer(s) who would bear the costs;
- A viable timeline to meet the imminent capacity needs; and
- A system that leaves the bulk options open until a study can be completed to determine the most appropriate bulk reinforcement option.

Of the options considered, the following three were selected for further technical assessment:

- Option 1: DESN on L28C/L29C
- Option 4: Tap onto W44LC/S47C
- Option 8: Upsize Wallaceburg TS

Option 1 is the most feasible approach to address the Dresden load capacity need for the following reasons:

- It is the minimum set of infrastructure that meets the firm capacity need with no stranded assets, regardless of the bulk reinforcement;
- It enables further load growth in the area and in the Chatham-Kent area; and
- It is the least-cost option that would enable customers to be connected promptly.

However, prior to bulk reinforcement, any load additions to this path would require similar interim measures to the Kingsville-Leamington loads, with a corresponding lower level of reliability. Further, there is the added risk to project approvals and timelines since an exemption approval would be required to implement interim measures, which is contingent on the having a west of London bulk plan in place as evidence of how the exemption would be remedied.

Option 4 is not preferred since it would not be timely or cost-effective. In order to avoid the bulk issue, the optimal location for load on this path would be east of Spence SS, such that the load is shed by configuration following a contingency. This would bypass the bulk problem, however, in order to do so, a lengthy 20 km tap line would be required, solely for the purposes of this load connection. This would not help the bulk transmission system or form part of a bulk reinforcement option, and once bulk reinforcements are in-place, this would be a stranded asset. The other alternative would be to use distribution feeders instead of the tap connection, however this would result in voltage concerns and low reliability due to the feeder length required.

Option 8 is not preferred since it cannot feasibly supply the firm load forecast. This option would bypass the bulk system concerns, however it would require significant upgrades to Wallaceburg equipment, the connecting circuit, and procurement and expansion of the station property itself. Beyond that, circuit upgrades or conversion of the circuit and station to 230 kV is a potential bulk reinforcement option, which would strand the majority of these costs.

Another alternative would be to defer the choice of a connection point until after the west of London bulk study is complete. There is the possibility that the recommendations from the bulk study could result in a better and more integrated connection point not assessed or even within the realm of this study scope. This would also support the approval of the connection point, rather than being contingent on future study results as with option 1.

Overall, there are two potential routes depending on the level of risk tolerance:

- Proceed with the design and build work for a DESN on the L28C/L29C circuits, with the caveat that the final connection is contingent on the publication of a west of London bulk study and accompanying recommendation for addressing bulk system needs – Not recommended;
- Incorporate the connection of this load in the west of London bulk study and re-evaluate the connection of this load as part of the bulk study - Recommended.

Proceeding with a connection and corresponding System Impact Assessment (SIA) ahead of the bulk study and regional coordination, this would be subject to the following risks:

- **Risk to load security:** Prior to a bulk reinforcement, interim measures will be required which will result in a lower level of reliability.
- **Risk to timelines:** The use of these interim measures will require a temporary exemption from ORTAC criteria and NPCC's criteria. Approval is contingent on a plan detailing the manner and time within which the exemption applicant will become compliant. A plan would require bulk reinforcement, which would be developed through the west of London bulk study. This study is on-going, but is interconnected with the Chatham-Kent/Lambton/Sarnia regional planning process, so timelines are not firm.
- **Risk to approval:** Interim measures will also take into account any costs that may be imposed on the IESO or on other market participants if the exemption were granted. Prior to a bulk reinforcement, the market solution to supply new loads in this area while respecting thermal limitations may result in higher market costs. New loads would require similar interim measures and exemptions as loads currently connecting in the Leamington area.

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Appendix E

Fleet Management Plan

BLUEWATER POWER DISTRIBUTION

FLEET MANAGEMENT PLAN;

OVERVIEW & FORECAST 2022-2027

January 1, 2022

CONTENTS

LIST OF TABLES

1. INTRODUCTION

1.1. Purpose of this Report

Bluewater Power Distribution Corporation (BWPD) Fleet services are provided by the Fleet Department under the direction of the Vice President of Operations. Services provided include purchasing, rental, inspection, maintenance, repair, and replacement of vehicles and equipment.

The purpose of this report is to provide a consolidated view of BWPD's Fleet management strategy, objectives, assets under management, and investment plan for the years 2022 to 2027 inclusive. The report includes a summary of asset data, condition evaluation criteria and condition assessments that form the basis on which Fleet capital investment plans have been formulated.

All information contained in this report is current as of January 1, 2022.

1.2. Overview

Fleet assets play a critical role in keeping the BWPD staff working efficiently and safely. These assets are required to be reliable and maintained in a safe and efficient manner. Vehicles not available for service when needed result in a slowdown of the work program, wasted time and labour in reorganizing and rescheduling work.

BWPD Fleet assets consist of 55 vehicles, 14 trailers and 11 pieces of specialty power-operated support equipment. Fleet assets have been divided into 5 asset categories:

1. Heavy Duty Boom - 17 Units
2. Medium Duty - 14 Units
3. Light Duty - 24 Units
4. Trailers - 14 Units
5. Support - 11 Units

Each has their own common set of asset condition parameters. A current listing of all BWPD's Fleet assets can be found later in Section 3 of this report.

BWPD performs regular inspection and maintenance on all fleet assets. The level of detail and frequency of inspection and maintenance is determined by asset category, regulatory requirements and condition of the asset.

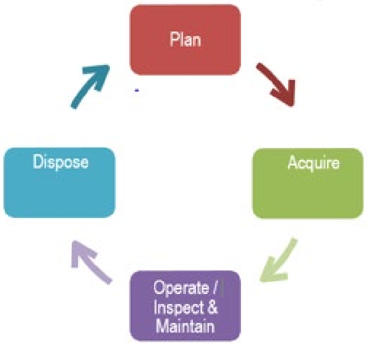
A history of the condition, maintenance, inspections, required repairs, and annual costs are documented and recorded in our Collective Data Fleet software program. We annually review costs and condition of all units as a part of our recommendations for vehicle upgrades and replacement. Other factors such as age, mileage, engine hours, PTO (Power Take Off) hours, appearance, and frequency of use are all contributors to the decision-making process to upgrade or replace an asset. This process is generally referred to as asset condition assessments (“ACA”)

2. FLEET ASSET MANAGEMENT PLAN

2.1. Strategy

BWPD's Asset Management Strategy for fleet assets uses a full lifecycle approach to managing its fleet assets. BWP is also focused on evidence-based decision-making.

Figure 2-1: BWP's Life Cycle approach to Fleet Management



Plan - BWP prepares and reviews annually a five-year replacement schedule which is informed by regular asset condition assessments (ACA). Due to the lead time it takes to budget, order, receive and place into service, vehicles are typically planned for replacement when ACA's indicate fair to poor condition. By the time the existing assets are removed from service, they will have normally deteriorated to poor or very poor condition.

Replacement of Heavy Duty Boom vehicles are ordered 12-18 months (or longer as seen with Pandemic conditions) in advance of replacement due to manufacturing wait times. Medium Duty work vehicles normally are ordered 12 months in advance and Light Duty vehicles such as trucks, trailers, and vans, are usually obtainable within the year they are being replaced.

Acquire – Detailed purchasing specifications are utilized for the largest and costliest assets. Specifications are reviewed and if needed updated before each acquisition. Any asset not considered a replacement, but an addition to the fleet at any point in time is determined by the size and scope of BWPD's forecast work program.

Operate, Inspect & Maintain – BWPD performs regular inspection and maintenance on all assets. Defects or deficiencies are recorded and flagged for action. The level of detail and frequency is determined by asset category, regulatory requirements and condition of the equipment. Table 2-1 provides a summary of Fleet Inspections and Maintenance schedules.

Table 2-1 Inspections and Maintenance

HEAVY DUTY BOOM	**FREQUENCY**
ARIEL DEVICE PM INSPECTION	4 MONTHS / 340 PTO HRS
ARIEL DEVICE ANNUAL INSPECTION	12 MONTHS / 1000 PTO HRS
ARIEL DEVICE DI ELECTRICAL INSULATION TEST	12 MONTHS
ARIEL DEVICE LEVELLING SYSTEM INSPECTION	5 YEARS (Depending on Manufacturer)
CVOR SAFETY INSPECTION	12 MONTHS
LOF SERVICE AND CHASSIS INSPECTION	6 MONTHS
MEDIUM DUTY	**FREQUENCY**
CVOR SAFETY INSPECTION	12 MONTHS
LOF SERVICE AND INSPECTIONS	6 MONTHS / 8000 KMS
LIGHT DUTY	**FREQUENCY**
LOF SERVICE AND INSPECTIONS	6 MONTHS / 8000 KMS
TRAILER	**FREQUENCY**
CVOR SAFETY INSPECTION	12 MONTHS
SUPPORT	**FREQUENCY**
LOF SERVICE AND INSPECTIONS	6 MONTHS / 8000 KMS
LIFTING DEVICE INSPECTIONS (FORKLIFTS)	12 MONTHS
ANNUAL SAFETY INSPECTION AND SERVICE (FORKLIFTS)	12 MONTHS

Day to day fleet management is the responsibility of BWPD's Fleet Mechanic Sub Foreman. BWPD maintains two licensed vehicle mechanics and a maintenance repair facility to correct deficiencies in a timely manner. BWPD also utilizes external contractors for specialized work or where it has been found to be cost effective.

Disposal – BWPD disposes of its Fleet assets when they are normally in poor or very poor condition. They are no longer economical, safe or reliable enough to withstand the daily rigors of utility operations or construction on high voltage lines. Vehicles for disposal are normally sold at auction or donated to college programs.

2.2. Objectives

Cost, risk and performance are balanced through a whole life cycle management strategy that takes assets from procurement to disposal.

To support the Fleet Asset Management Strategy, the following objectives were developed:

- maximize the operational effectiveness of the workforce by maximizing operational functionality and availability of the vehicles;
- maximize asset longevity through effective purchasing specifications, operational inspections and maintenance;
- minimize total lifecycle costs by tracking operational and maintenance costs as well as downtime costs;
- maximize safety of the fleet by minimizing accidents and incidents.

BWPD manages its fleet to ensure these objectives can be achieved consistently and are sustainable over time.

3. ASSETS UNDER MANAGEMENT

Fleet assets under management consist of 55 vehicles, 14 trailers and 13 pieces of specialty-power operated support equipment. Fleet vehicles have been divided into five asset categories, each with their own common set of asset condition parameters.

Heavy Duty Boom

BWPD normally maintains a fleet of approximately 18 large vehicles equipped with aerial work platforms or lifting devices. These vehicles are equipped with specialized equipment such as articulating insulated booms, rotating turrets, hydraulic systems and more. They are designed to safely and quickly lift workers and materials into the air to perform line construction and maintenance functions. In this group are Single and Double Bucket Trucks and Radial Boom Derricks. These vehicles are special ordered, custom made and have long delivery lead times, generally around 12-18 months.

Table 3-1: Fleet Inventory – Heavy Duty Boom

Unit #	Year	Make / Ariel Device Manufacturer	Equipment Type	Age	Life Expectancy
11	2006	Freightliner / Posi Plus	Single Bucket	14 YRS	15 YRS
18	2008	Freightliner / Posi Plus	Double Bucket/Elevator	12 YRS	15 YRS
24	2021	Freightliner / Terex	Radial Boom Derrick	0 YRS	15 YRS
38	2005	International / Altec	Single Bucket	15 YRS	15 YRS
67	2007	Freightliner / Posi Plus	Single Bucket	13 YRS	15 YRS
80	2010	Freightliner / Terex	Radial Boom Derrick	10 YRS	15 YRS
81	2011	Freightliner / Posi Plus	Single Bucket	9 YRS	15 YRS
84	2011	Freightliner / Posi Plus	Single Bucket	9 YRS	15 YRS
91	2011	Freightliner / Terex	Radial Boom Derrick	9 YRS	15 YRS
98	2013	Freightliner / Posi Plus	Single Bucket	7 YRS	15 YRS
113	2016	Freightliner / Altec	Single Bucket	4 YRS	15 YRS
122	2017	Freightliner / Terex	Radial Boom Derrick	3 YRS	15 YRS
124	2017	Freightliner / Posi Plus	Double Bucket	3 YRS	15 YRS
134	2018	Ford / Altec	Single Bucket	2 YRS	15 YRS
135	2018	Ford / Altec	Single Bucket	2 YRS	15 YRS
137	2018	Ford / Altec	Back yard Unit	2 YRS	15 YRS
147	2021	Freightliner / Posi Plus	Single Bucket	0 YRS	15 YRS

3.2. Medium Duty Vehicles

BWPD normally maintains a fleet of approximately 15 vehicles in this category. They are normally larger vehicles used to transport workers, equipment, tools and test equipment to work sites. Used by the Lines department, they do not have any aerial lifting devices or work platforms. These vehicles are special ordered, and have a delivery lead time generally between three and twelve months.

Table 3-2: Fleet Inventory – Medium Duty Vehicles

Unit #	Year	Manufacturer	Equipment Type	Age	Life Expect
74	2006	Ford	E450	14 YRS	10 YRS
77	2010	Dodge	Ram 2500	10 YRS	10 YRS
97	2013	Dodge	RAM 5500	7 YRS	10 YRS
99	2014	Chevrolet	2500 HD Pickup	6 YRS	10 YRS
107	2015	Chevrolet	Silverado	5 YRS	10 YRS
108	2015	GMC	Sierra 2500	5 YRS	10 YRS
111	2008	Chevrolet	3500 Bubble van	12 YRS	10 YRS
116	2011	Chevrolet	2500 HD Pickup	9 YRS	10 YRS
121	2017	GMC	2500 HD Pickup	3 YRS	10 YRS
131	2018	GMC	2500 HD Pickup	2 YRS	10 YRS
132	2018	GMC	2500 HD Pickup	2 YRS	10 YRS
133	2018	GMC	2500 HD Pickup	2 YRS	10 YRS
140	2019	GMC	2500 HD Pickup	1 YRS	10 YRS
145	2020	GMC	2500 HD Pickup	0	10 YRS

3.3. Light Duty Vehicles

This category is normally comprised of approximately 25 small vehicles for the transportation of staff, light tools and equipment. Made up of pickup trucks, vans, SUVs and cars, they are normally ordered from local dealerships and have delivery times of less than 12 months. Most however do require special outfitting before they can be placed into service and function in their role as a utility fleet vehicle.

Table 3-3: Light Duty Vehicles

Unit #	Year	Manufacturer	Equipment Type	Age	Life Expect
62	2006	Pontiac	Vibe	14 YRS	10 YRS
71	2005	Ford	Focus	15 YRS	10 YRS
73	2009	Pickup	Dodge Dakota	11 YRS	10 YRS
82	2007	Dodge	Ram 1500	13 YRS	10 YRS
86	2012	Dodge	Caravan	8 YRS	10 YRS
87	2012	Dodge	RAM 1500	8 YRS	10 YRS
89	2012	Dodge	Ram 1500	8 YRS	10 YRS
90	2018	Ford	Explorer	2 YRS	10 YRS
92	2013	Dodge	RAM 1500	7 YRS	10 YRS
95	2013	Dodge	RAM 1500	7 YRS	10 YRS
101	2014	Ford	Focus EV	6 YRS	10 YRS
102	2014	Dodge	RAM 1500	6 YRS	10 YRS
103	2014	Dodge	RAM 1500	6 YRS	10 YRS

106	2015	Dodge	Caravan	5 YRS	10 YRS
109	2016	Chevrolet	Sierra 1500	4 YRS	10 YRS
112	2016	Dodge	Caravan	4 YRS	10 YRS
117	2017	Dodge	Caravan	3 YRS	10 YRS
118	2017	Dodge	Caravan	3 YRS	10 YRS
119	2017	Honda	Accord	3 YRS	10 YRS
126	2017	Ford	Explorer	3 YRS	10 YRS
136	2018	Ford	Escape	2 YRS	10 YRS
141	2019	Chevrolet	Equinox	1 YRS	10 YRS
144	2020	Dodge	Caravan	0 YRS	10 YRS
148	2021	Chevrolet	Traxx	0 YRS	10 YRS

3.4. Trailers

This category is comprised of an assortment of Pole, Utility, Stock, and Enclosed trailers. The approximately 15 pieces of equipment are special ordered, custom made and each have unique delivery lead times.

Table 3-4: Trailers

Unit #	Year	Manufacturer	Equipment Type	Age	Life Expect
44	1995	Utilequip	UT1	25 YRS	15 YRS
46	1976	Havelock Hauler	391	44 YRS	15 YRS
48	2007	Utilequip	PT96	13 YRS	15 YRS
49	2009	USCA-USA	Cargo Trailer	11 YRS	15 YRS
100	2014	J&J Trailers	PT1	6 YRS	15 YRS
105	2015	TJ Trailers	Stealth Titen SE	5 YRS	15 YRS
120	2017	Slabach	Reel Trailer	3 YRS	15 YRS
123	2017	Utilequip	Pole Trailer	3 YRS	15 YRS
125	2017	Canada Trailer	Float/Reel Trailer	3 YRS	15 YRS
127	2018	Legend	Enclosed Trailer	2 YRS	15 YRS
138	2006	Big Tex	CAR TRAILER	14 YRS	15 YRS
139	2019	Legend	Enclosed Trailer	1 YRS	15 YRS
142	2019	Utilequip	UTILITY/REEL	1 YRS	15 YRS
143	2020	Canada Trailer	UTILITY/MAT	0	15 YRS

3.5. Support Vehicles

This category makes up the remainder of BWPD's fleet vehicles. It consist of vehicles with special uses that do not fit in to the other categories. They consist of Forklifts, Tension Stringers, Skid Steers, Lighting units and Lawn care equipment. They are all special order equipment and have various lead times when ordered for replacement.

Table 3-5: Support Vehicles

Unit #	Year	Manufacturer	Equipment Type	Age	Life Expectancy
52	1995	Timberland	30B Tension Stringer	25 YRS	15 yrs
53	1995	Timberland	30B Tension Stringer	25 YRS	15 yrs
64	2006	Toyota	7FGU30 Forklift	14 YRS	15 yrs
114	2021	Bobcat	T-770 Skid Steer	0	15 yrs
110	2013	Bobcat	Toolcat 5600	7 YRS	15 yrs
115-1	2015	Wacker Neuson	Tower Lights	5 YRS	15 yrs
115-2	2015	Wacker Neuson	Tower Lights	5 YRS	15 yrs
128	2014	Toyota	Electric Forklift	6 YRS	15 yrs
56	1987	John Deere	Lawn Mower	33 YRS	15 yrs
69	2007	Kubota	Lawn Mower	13 YRS	15 yrs
129	2017	Kubota	Lawn Mower	3 YRS	15 yrs

4. FLEET ASSET CONDITION ASSESSMENTS

Fleet assets are monitored from acquisition through to disposal and detailed records of maintenance and condition are kept. BWPD's fleet maintenance activities are planned to ensure the operational effectiveness, longevity and safety of fleet assets.

Asset condition evaluation parameters have been developed for each asset category. The criteria are based on degradation conditions that lead to the asset's end of life. These parameters are used as the defining criteria when we meet each year to make recommendations on vehicle replacements and budgets for the following year.

Condition parameters were developed by BWPD and are a function of manufacturer recommendations, regulatory requirements, industry practices, and the expertise and judgement of BWPD's licensed vehicle maintenance staff.

Table 4-1 shows the Asset Condition Evaluation Parameters for each category of asset.

Table 4-1

Asset Category	Evaluation Parameters considered for Replacement
Heavy Duty Boom	1. Age - Try to limit to 15 Yrs 2. Condition 3. Mileage - Try to limit to 200,000 Km 4. Engine and PTO Hrs 5. Type of Equipment 6. Frequency of Use
Medium Duty	1. Age - Try to limit to 15 Yrs 2. Condition 3. Mileage- try to limit to 200,000 Km
Light Duty	1. Age - Try to limit to 10 Yrs 2. Condition 3. Mileage - try to limit to 200,000 Km
Trailers	1. Age - Try to limit to 15 Yrs 2. Condition
Support	1. Age - Try to limit to 15 Yrs 2. Condition

5 CAPITAL INVESTMENT PLAN 2022-2027

5.1. Forecast Fleet Asset Replacements

BWPD's Fleet Department meets annually to review all Fleet assets and to make recommendations to the Board of Directors on what vehicles require replacement, upgrade or elimination. Below is a table indicating our findings for the future. Year 2022 recommendations are based on the full criteria parameters for replacement however years 2023-2027 are solely based on vehicle age and mileage forecast. Dollar values are based on current costs, and not adjusted for inflation. We will meet later this year and discuss vehicle replacement for 2023 depending on findings of the ACA's this year.

Table 5-2: Forecast Fleet Replacement Tables for 2022-2027

2022		
VEHICLE # AND CATEGORY	**COST**	**AGE, CONDITION**
77 Medium Duty	$145,000.00	12, Fair
99 Medium Duty	$61,000.00	8, Poor
NEW 65' BUCKET TRUCK	$490,000	
DECK, RE-HOSE #11	$30,000	
TOTAL= $ 726,000.00		

2023		
VEHICLE # AND CATEGORY	**COST**	**AGE, CONDITION**
No Heavy Duty Boom		
111 UNDERGROUND TRUCK	$150,000.00	14, Poor
87 Light Duty	$60,000.00	11,
89 Light Duty	$60,000.00	11
TOTAL= $ 270,000.00		

2024

VEHICLE # AND CATEGORY	COST	AGE
Replace 38	$350,000.00	17, Poor
95 Light Duty	$60,000.00	11
69 Support	$15,000.00	17
TOTAL= $ 425,000.00		

2025

VEHICLE # AND CATEGORY	COST	AGE
NO Heavy Duty Boom		
107 Medium Duty	$60,000.00	10
106 Light Duty	$45,000.00	10
TOTAL= $105,000.00		

2026

VEHICLE # AND CATEGORY	COST	AGE
67 Heavy Duty Boom	$350,000.00	17
112 Light Duty	$35,000.00	10
TOTAL= $ 385,000.00		

2027

VEHICLE # AND CATEGORY	COST	AGE
LG Truck 134 & 135	$450,000.00	
121 Medium Duty	$60,000.00	10
117 Light Duty	$40,000.00	10
118 Light Duty	$40,000.00	10
TOTAL= $ 590,000.00		

BLUEWATER POWER
DISTRIBUTION CORPORATION

Appendix F

Capital Project Sheets

	CAPITAL PROJECT SUMMARY SHEET **GENERAL PLANT**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT10 Vehicle Replacement $270,000

A. General Information on the project/program

Project Summary

Vehicle replacements are identified through Bluewater's comprehensive fleet management system, as further described in Bluewater's Fleet Management Plan, attached as an appendix to this DSP.

In 2021, Bluewater introduced a fleet GPS tracking software device that is capable of tracking kilometers driven, litres of fuel per kilometer, corrective maintenance, planned maintenance, and required testing for each vehicle in its fleet. This management system assists in maximizing the useful life of Bluewater's vehicles, as well as justifying the need for replacement. It also is capable of electronic vehicle inspections for CVOR vehicles (DVIR), which became legislated in June of 2022.

The decision to replace vehicles is typically driven by the desire to reduce O&M costs, although there are several factors that come into play when Bluewater makes a decision to replace a vehicle. Data is utilized that has been collected in regard to engine hours, kilometers traveled, operator feedback, operator safety, and consideration of whether the vehicle design continues to meet Bluewater's requirements. When the analysis indicates that a vehicle is below Bluewater's standard for safety, economic viability, or intended work design, the truck is identified for replacement.

Bluewater works from a five-year capital plan to prepare for vehicle budgeting. For the purchase of large fleet vehicles, a team comprised of users, a mechanic, and a management supervisor is created to review the products of different manufacturers and request authorization early in the budget process.

Bluewater seeks pre-approval from the Board of Directors in the spring of the year prior to the delivery. Following budget approval from the Board of Directors, the team moves into deeper analysis, utilizing demonstration vehicles, as well as discusses reliability, warrantee response and overall vehicle satisfaction with other LDCs who have purchased similar equipment.

The Materials Management Department prepares an RFP based on team results and sends it out to the chosen manufacturers who have met the desired vehicle criteria. The contract is awarded based on the manufacturer meeting the required specifications, cost and overall support from the team.

The vehicles were often ordered in the fall after Board approval. It then took approximately one year from the date of the order for vehicle delivery, but with the onset of the COVID-19 Pandemic, parts, cab, and chassis for the trucks are delayed to a point of a two-year delivery from time of order.

Spending based on the above analysis for Vehicle Replacement is shown in the chart below, and further details may be found in Bluewater's Fleet Management Plan.

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Vehicle Replacement	1,080,380	551,622	281,054	996,818	514,836	730,000	270,000

Capital Contributions to a Transmitter	No capital contributions or cost recovery will be made to the transmitter.	
Customer Attachments and Load	Not applicable.	
Project Dates and Expenditure Timing	**Start Date:** January 2023	**In-Service Date:** December 2023
Risks to Completion	Risk to completion is based on delivery of trucks from required suppliers. The mitigation plan is to ensure close co-ordination between engineering, operations, and purchasing staff to ensure trucks are ordered in advance and delivered in a timely manner by the suppliers.	
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.	
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).	

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The decision to replace vehicles is typically driven by the desire to reduce O&M costs, as well as replacing equipment at the end of its service life due to failure, risk of failure, or substandard performance to address safety, efficiency and reliability criteria.
	b) Good Utility Practice Customers will benefit from improved reliability. The availability of vehicles to ensure necessary reactive and proactive work is completed in a timely manner required to support reliability of the distribution system.
	c) Investment Priority This project is a medium range priority. Vehicles are budgeted for replacement on a 10 to 15 year basis, due to maintenance costs and reliability.
	d) Analysis of Project and Alternatives Bluewater's philosophy with vehicle management is to run until failure. Routine replacement ahead of failure would lead to higher costs and significant staff time. Bluewater maintains some vehicles that are not

	regularly employed for emergency situations, which saves rental vehicle costs. Customer engagement confirmed that customers support planned General Plant investments and rank reducing the length and number of power outages as high priorities.
2. Safety	Employees work on live, high voltage lines; it is necessary to maintain vehicles that are reliable with up-to-date technology to ensure their safety. Newer vehicles have enhanced safety features.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Co-ordination of anticipated vehicle delivery dates will be confirmed with suppliers. The investment will enable future technological functionality, as the availability of vehicles ensures the necessary reactive and proactive work is completed. Investments are also made for bucket trucks and equipment to meet our needs of our changing infrastructure as well as smaller more efficient vehicles to meet the needs of other departments.
5. Environmental Benefits	Newer vehicles employ the regen system, which reduces the amount of diesel fuel particulates being released into the environment. LED lights on the trucks are able to provide light for longer periods of time than halogen lighting, without requiring the truck to run or using the truck's battery.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis is completed based on maintenance costs and the cost to replace the vehicles.
Business Case	As per Chapter 5 of the filing requirements, this project does not "substantially exceed" the materiality threshold requiring the filing of a business case.

	CAPITAL PROJECT SUMMARY SHEET **GENERAL PLANT**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT12 Transformers $165,000

A. General Information on the project/program

Program Summary

This program consists of transformers purchased for inventory and upcoming projects.

Funding of the transformer inventory enhances customer reliability by ensuring an adequate level of inventory to replace transformers reasonably anticipated to require replacement in the year. The history of this utility as a merged entity representing six hydro-electric commissions, the largest of which was itself a merger with former Ontario Hydro territory, means that a broad range of transformers are required in order to ensure proper levels of back-ups for emergencies.

The transformer inventory has become increasingly critical as delivery times of transformers have increased, ranging anywhere from twenty-four weeks up to twenty-six weeks. Delivery concerns, as well as rising costs, have meant an increased focus by Bluewater Power on refurbishing transformers only where the refurbishment can be economically justified and technically viable. Therefore, although efforts are underway to reduce costs, a reduction in the strategic reserve would create an unacceptable level of risk to customer reliability.

Annual operating and maintenance cost may be reduced due to fewer outages as related to newer installed infrastructure.

Spending for Transformers is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Transformers	141,354	36,822	247,427	63,918	207,064	150,000	165,000

Pacing for the Bridge and Test years is paced based on the 5-year historical average plus inflation.

Capital Contributions to a Transmitter

No capital contributions or cost recovery will be made to the transmitter.

Customer Attachments and Load

No new customer connections.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2023

Risks to Completion

Risk to completion is based on delivery of transformers from required suppliers. The mitigation plan is to ensure close co-ordination between engineering, operations and purchasing staff to ensure transformers are ordered early each year (and throughout the year as required) and delivered in a timely manner by the suppliers.

Total Capital and O&M Costs

Not applicable. Bluewater does not have REG investments in the forecast DSP period.

Associated with REG Investments	
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** This project is driven by reliability, efficiency, and customer value criteria.
	b) Good Utility Practice Customers will benefit from improved reliability with the immediate availability of replacement transformers
	c) Investment Priority The priority of this program is high, because Bluewater Power's strategic transformer inventory is a critical component of its capital asset program. It enables the utility to respond to transformer failures caused by end-of-life or storm-related damage.
	d) Analysis of Project and Alternatives Not applicable.
2. Safety	Any transformer that is damaged from adverse conditions will be replaced immediately in the system increasing overall safety.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Limited co-ordination is required with other utilities. However, co-ordination is required on delivery of transformers from required suppliers so they are ordered and delivered in a timely manner by the suppliers.
5. Environmental Benefits	Limited impact.
6. Conservation and Demand Management	Improved reliability by maintaining and replacing damaged infrastructure continues to support economic development.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Customer satisfaction is affected by reliability. This strategic transformer inventory is required in order to maintain system reliability by ensuring replacement transformers are available in the event of an unplanned failure. If a failure were to occur, the outage would be unplanned and will likely have a greater negative impact to the customers and their facility. Funding of the transformer inventory enhances customer reliability by ensuring an adequate level of inventory to replace transformers reasonably anticipated to require replacement in the year. The transformer inventory has become increasingly critical as delivery times of transformers have increased, ranging anywhere from twenty-four weeks up to twenty-six weeks. Any reduction in the strategic reserve and a do nothing or reactive approach would create an unacceptable level of risk to customer reliability.

Business Case	As per Chapter 5 of the filing requirements, this project does not “substantially exceed” the materiality threshold requiring the filing of a business case.

CAPITAL PROJECT SUMMARY SHEET
GENERAL PLANT

Project Number(s): UT19
Project Name: Service Centre
2023 Budget: $150,000

A. General Information on the project/program

Project Summary

An annual budget is established to maintain, repair, and improve Bluewater Power's Service Centre.

The Service Centre is Bluewater Power's main office and houses Administration, Customer Service, Engineering, Operations, and Purchasing for Bluewater Power. All repairs are required for security, health and safety, building integrity to protect equipment located within the Service Centre, as well as aesthetics.

Improvement at the centre is an on-going program that is required to keep Bluewater Power's main building in reasonable condition. The main building is approximately 55 years old and requires maintenance and repairs with respect to items such as:

- Replacements of old and/or defective windows, doors, and fences
- Heating and cooling upgrades
- Roof repairs, as required
- Landscaping, as required
- New facade and exterior lighting

In 2023, Bluewater will be updating the exterior by replacing siding. Bluewater will also be adding exterior lighting for security.

Spending for the Service Centre is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Service Centre	80,100	87,198	193,164	187,543	659,469	200,000	150,000

Bluewater has paced spending in the Bridge and Test years at a similar pace to the 5-year historical average.

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2023

Risks to Completion

The risk to non-completion is low. Third party contractors will be used, but we do not anticipate any difficulty scheduling jobs as needed.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval	This program does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** Repairs and maintenance must be performed to ensure the continued use of our Service Centre
	b) Good Utility Practice By maintaining our facilities, our equipment will be kept secure and in good condition, ensuring it is ready for daily use.
	c) Investment Priority The priority of this program is high. While the building known as our Service Centre does not directly affect the reliability and operation of our distribution system, it does house all of our personnel, vehicles, equipment and IT infrastructure needed to run out system.
	d) Analysis of Project and Alternatives Options including to do nothing or replace items upon failure. We anticipate this would cost more than proactively replacing worn equipment.
2. Safety	Secure windows, doors and fencing will help to ensure the safety of our employees.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Not applicable.
5. Environmental Benefits	New furnaces, windows and doors will be more energy efficient.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	A financial analysis cannot be done for maintenance and repairs to our building since they are required to keep the building functional. Improvements can be deferred but only for a period of time before they are required as a repair or maintenance.
Business Case	As per Chapter 5 of the filing requirements, this program does not “substantially exceed” the materiality threshold requiring the filing of a business case.

CAPITAL PROJECT SUMMARY SHEET
GENERAL PLANT

Project Number(s): IT1

Project Name: Data Centre Lifecycle

2023 Budget: $185,000

A. General Information on the project/program

Project Summary

This capital effort concerns the corporate Data Centre. It includes network, server, storage, security, electrical, HVAC, and other data centre equipment, along with related software. The datacentre services and equipment are implemented and upgraded primarily on a lifecycle basis unless change is driven by a new business software platform expansion.

Depending on equipment the lifecycle is generally 5 to 8 years. However, an analysis is done on each datacentre component to ensure replacements and upgrades are necessary. For example, the network stack was in place for more than 12 years prior to replacement. The general plan is dictated by changing technology requirements, pending obsolescence, equipment failure, and access to improved technology that will enhance business practice and or customer experience.

In 2023, there is a plan to replace 2 servers ($40,000), upgrade all servers to the latest OS software ($70,000), expand a data centre environmental monitoring solution ($35,000), and replace a cooling unit ($40,000).

These projects will be carried out throughout 2023. Each instance will be managed through a variety of project management tools depending on project scope and complexity.

Spending for this project is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Data Centre	78,026	108,752	306,220	569,290	396,339	290,000	185,000

Historical spending for these projects has varied, but for Test and forecast years, Bluewater has sought to smooth the spending out at an average level; variations still occur due to project needs.

Capital Contributions

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2023

Risks to Completion

Risks to completion are minimal. This project is part of a program that is successfully executed each year. The availability of resources (internal or external) is sufficient to complete this project.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** This project deals with ensuring continuity of technology platforms, and advancing customer and business functions, as well as providing mitigating solutions to guard against cyber security threats.
	b) Good Utility Practice All customers may be impacted, as systems that create their bills and handle their calls will be updated. Maintaining the data centre ensures that employees are able to continue with business functions so that customer information and billing are accurate and reliable.
	c) Investment Priority **High:** The datacentre is the centre of all computing platforms and the focus on network and security is critical to the operation of the datacentre and subsequently Bluewater Power's business.
	d) Analysis of Project and Alternatives Limited consideration. Technology changes rapidly and replacement must be scheduled to ensure business continuity and security. The 2020 Customer Survey confirmed that 82% of customers felt in terms of General Plant spending that "while Bluewater should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably."
2. Safety	Not applicable.
3. Cyber Security, Privacy	Ensuring that the data centre is up to date with current and patched technology assists in the overall security and privacy of employee and customer information.
4. Co-ordination, Interoperability	Not applicable.
5. Environmental Benefits	Newer technology is more efficiently operated, thereby reducing electricity consumption.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis is based on lifecycle expectations as provided by manufacturers, along with historical data of usages. Consideration is not given to run to failure as most business functions rely on solidly functioning datacentre services.
Business Case	As per Chapter 5 of the filing requirements, this project does not "substantially exceed" the materiality threshold requiring the filing of a business case.

	CAPITAL PROJECT SUMMARY SHEET **GENERAL PLANT**	**Project Number(s):**	IT2
		Project Name:	Computer Infrastructure Lifecycle
		2023 Budget:	$200,000

A. General Information on the project/program

Project Summary

This capital project is for the acquisition and implementation of computers, mobile devices, printers, peripherals, and other technical office equipment.

Bluewater operates on a 4-year lifecycle approach to PCs and variable year lifecycle approach to other infrastructure technology such as laptops, printers, peripherals, and other technical office equipment. This practice enables standardization of products and related services and keeps a consistent financial impact to budgets.

Spending for this project is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Computer Infrastructure	153,966	210,443	270,811	211,994	175,649	200,000	200,000

Pacing for the Bridge and Test years aligns with the 5-year historical average of $205,000.

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: January 2023	**In-Service Date:** December 2023

Risks to Completion

Risks to completion are minimal. This project is part of a program that is successfully executed every year. The availability of resources (internal or external) is sufficient to complete this project.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval

This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability

a) Investment Driver

This project is driven by ensuring continuity of technology platforms.

b) Good Utility Practice

All customers may be impacted, as employees use these devices to manage customer accounts and interactions.

c) Investment Priority

	High: Due to COVID-related supply chains, our regular lifecycle was interrupted. In 2023, it's critical that we return to the regular lifecycle rollout.
	Analysis of Project and Alternatives Limited consideration. Technology changes rapidly and replacement must be scheduled to ensure business continuity and security. The 2020 Customer Survey confirmed that 82% of customers felt in terms of General Plant spending that "while Bluewater should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably."
2. Safety	Not applicable.
3. Cyber Security, Privacy	Ensuring these solutions are up to date with current technology assists in the overall security and privacy of employee and customer information.
4. Co-ordination, Interoperability	Not Applicable.
5. Environmental Benefits	Not Applicable.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis is based on lifecycle expectations as provided by manufacturers, along with historical data of usages. Consideration, in this case, is given to run to failure in some cases by retaining small numbers of additional hardware on hand. However, business functions do rely on properly functioning hardware and the most efficient way to ensure this is with a consistent lifecycle approach.
Business Case	As per Chapter 5 of the filing requirements, this project does not "substantially exceed" the materiality threshold requiring the filing of a business case.

<table>
<tr><td></td><td>CAPITAL PROJECT SUMMARY SHEET
GENERAL PLANT</td><td>Project Number(s):
Project Name:
2023 Budget:</td><td>IT3
Corporate IT Security
$220,000</td></tr>
<tr><td colspan="4">A. General Information on the project/program</td></tr>
<tr><td>Project Summary</td><td colspan="3">In ongoing efforts to mitigate heightened and ever-changing cyber threats, Bluewater Power needs to further increase preparedness against both internal and external security attacks.

While this has been a regular focus, in 2023, compliance with the OEB Cyber Security Framework ($110,000), security related aspects of Green Button ($35,000), Multi-Factor Authentication ($50,000), and Identity and Access Management ($25,000), will take precedence in the planned investments.

Spending for this project for the Bridge and Test Years is shown in the chart below:
<table><tr><td></td><td>2022 Bridge</td><td>2023 Test</td></tr><tr><td>Corporate IT Security</td><td>240,000</td><td>220,000</td></tr></table></td></tr>
<tr><td>Capital Contributions to a Transmitter</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td>Start Date: January 2023</td><td colspan="2">In-Service Date: December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">Risks to completion are minimal. This project is part of a program that is successfully executed each year. The availability of resources (internal or external) is sufficient to complete this project.</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="4">B. Evaluation Criteria and Information Requirements</td></tr>
<tr><td rowspan="2">1. Efficiency, Customer Value, Reliability</td><td colspan="3">a) Investment Driver

This project is aimed at providing mitigating solutions to guard against cyber security threats and ensuring continuity of technology platforms.</td></tr>
<tr><td colspan="3">b) Good Utility Practice

All customers may be impacted by cyber threats and, therefore, increased security measures must be in place.</td></tr>
</table>

	c) Investment Priority High. IT cyber security risk mitigation is an activity that demands continuous attention because the threat landscape rapidly evolves. Bluewater Power is required to adhere to the Cyber Security Framework as part of regulation and this investment forms part of that requirement.
	d) Analysis of Project and Alternatives The requirement to keep cyber security risk mitigation projects current is business best practice and OEB mandated.
2. Safety	Not applicable.
3. Cyber Security, Privacy	The primary focus of this effort is cyber security and privacy.
4. Co-ordination, Interoperability	Not Applicable
5. Environmental Benefits	Not Applicable.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis of cyber security projects is based on lifecycle of hardware (firewalls, for example) as per manufacturer and industry recommendation, response to threat mitigation (constantly evolving), and regulatory requirement (OEB Cyber Security Framework).
Business Case	As per Chapter 5 of the filing requirements, this project does not “substantially exceed” the materiality threshold requiring the filing of a business case.

CAPITAL PROJECT SUMMARY SHEET GENERAL PLANT	**Project Number(s):**	IT4
	Project Name:	Internal Technology Development
	2023 Budget:	$425,000

A. General Information on the project/program

Project Summary

Throughout the year, Bluewater IT staff perform a number of tasks and projects to create new products and services or to develop existing IT assets. These projects are completed entirely in-house, by Bluewater staff. Over time, the Product Development Team has created a number of applications. These are built and further developed within this capital project. Two examples of this are Tally, an internal employee portal for time and vacation management, and MyAccount, which is the customer portal to insight and management of customer electricity accounts.

2023 will focus on two projects that introduce new solutions and upgrades to three existing products. The first project is an MDM/R integration toolset that will enhance the existing data exchange and eliminate the current third party AS2 Management Tool ($90,000). The second is a Mobility Proof of Concept application that will focus on Field Operations Management ($220,000). Existing products upgrades include MyAccount ($65,000), Tally ($25,000), and ARC (Document Management) ($25,000).

Spending for this project is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Internal Technology	313,973	346,005	311,763	344,802	372,210	390,000	425,000

Pacing for the Bridge and Test years aligns with the 5-year historical average.

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2023

Risks to Completion

Risks to completion are minimal. This project is part of a program that is successfully executed each year. The availability of resources (internal or external) is sufficient to complete this project.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval

This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).

B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** This project is aimed at advancing customer and business functions.
	b) Good Utility Practice This project provides increased customer value and business process efficiencies.
	c) Investment Priority **Medium:** The project developments are significant to the progression of Bluewater Power business functions and to bettering our customer experience. This capital focus follows the guiding principal of advancing Customer and Business Functions. Development can sometimes be interrupted by things such as new regulations that demand strict timelines.
	d) Analysis of Project and Alternatives Most of this cost is employee labour. Market alternatives are considered for each new project.
2. Safety	Not applicable.
3. Cyber Security, Privacy	Both cyber security and privacy are identified in the design and development of these solutions.
4. Co-ordination, Interoperability	Sometimes, customer-facing solutions are identified in the design and development of these solutions.
5. Environmental Benefits	Not Applicable.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis of these projects includes the ability to provide better services to customers and increased efficiencies to business function. Doing nothing is considered, however, Bluewater Power would not be responsive to customer engagement responses and not continuing projects of this nature would soon place Bluewater Power too far behind to practically catch up to rapidly changing technology expectations.
Business Case	As per Chapter 5 of the filing requirements, this project does not “substantially exceed” the materiality threshold requiring the filing of a business case.

	CAPITAL PROJECT SUMMARY SHEET **GENERAL PLANT**	**Project Number(s):** **Project Name:** **2023 Budget:**	IT5 Legislated Business Application Upgrades/SAP Improvements $300,000

A. General Information on the project/program

Project Summary

This project includes development and changes to SAP, ODS, AMI and associated applications. These generally are in response to changes in regulation and or continuous improvements. Whenever possible (and the majority of the time), internal resources are used to complete these development efforts. Alternatively (but rarely), third party assistance will be used.

Development is required to perform OEB and Ministry of Energy legislated changes to internal business processes along with continuous solution improvements. For example, the Ontario Electricity Rebate (OER), COVID-19 Energy Assistance Program (CEAP), and the Arrears Management Program, etc.

The primary focus of 2023 will be Green Button. Under the direction of the Ministry of Energy, Northern Development and Mines, Ontario electricity LDCs and natural gas distributors will be required to implement the Green Button Initiative with a deadline for go live in November 2023. Green Button is a North American Energy Standards Board standard whereby utilities must provide customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format. In Ontario, the regulation would require utilities to develop or procure a software solution to implement Green Button in accordance with the NAESB ESPI standard rules and provide energy data to authorized third party services, on the consent of the consumer and in accordance with the standard. Within the budgeted amount, Green Button expenditures are expected to be $240,000. The remainder will be used for other regulatory change requirements.

Spending for this project is shown in the chart below, along with primary project names:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Legislated Business App. Upgrades	Ontario Fair Hydro Plan Retailer Bill Allowances Rate Riders and Changes	Ontario Electricity Support Program (OESP) Rate Riders and Changes	Distribution System Code and the Unit Sub-Metering Code Changes Dunning Enhancements	Comprehensive Energy Plan Ontario Electricity Rebate Changes Global Adjustment	Rimini Street Support Conversion Rate Riders and Changes	Green Button Queries Database Dunning Changes Replacement of Settlement System	Green Button Rates Changes Market Renewal
	119,285	132,652	137,043	118,684	80,365	250,000	300,000

Capital Contributions	Not applicable.	
Customer Attachments and Load	Not applicable.	
Project Dates and Expenditure Timing	**Start Date:** January 2023	**In-Service Date:** December 2023
Risks to Completion	Risks to completion are minimal. These projects are either in response to regulatory requirements or a business improvement focus. The availability of internal resources should be is sufficient to complete these projects.	
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.	
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).	
B. Evaluation Criteria and Information Requirements		
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** This project is driven by regulatory change requirements.	
	b) Good Utility Practice This project provides increased customer value and business process efficiencies.	
	c) Investment Priority **High:** Legislated changes are always a high priority. The Green Button directive requires LDCs to have the standard in place in 2023.	
	d) Analysis of Project and Alternatives OEB regulations are required. Any system improvements are not wholesale in nature in this program.	
2. Safety	Not applicable.	
3. Cyber Security, Privacy	Cyber security and privacy are part of all development mappings.	
4. Co-ordination, Interoperability	Not Applicable.	
5. Environmental Benefits	Not Applicable.	
6. Conservation and Demand Management	Not Applicable.	
C. Category-Specific Requirements: GENERAL PLANT		
Results of Quantitative and Qualitative Analyses	These projects are regulatory in nature and, as such, are a requirement.	
Business Case	As per Chapter 5 of the filing requirements, this project does not “substantially exceed” the materiality threshold requiring the filing of a business case.	

<table>
<tr><td></td><td>CAPITAL PROJECT SUMMARY SHEET
GENERAL PLANT</td><td>Project Number(s):
Project Name:
2023 Budget:</td><td>IT9
Disaster Recovery Plan Upgrade
$158,000</td></tr>
<tr><td colspan="4">A. General Information on the project/program</td></tr>
<tr><td>Project Summary</td><td colspan="3">The Disaster Recovery project is an ongoing project to implement, maintain, and improve the technical risk mitigation of the corporate computing systems. The existing disaster recovery plan will continually evolve in order to support the expanded service offerings and business demands. This project will grow and or keep current, a best practice DR solution which includes the procurement of necessary hardware and software.

The focus in 2023 will be to implement a new environmental management solution for the DR Datacentre site. The primary function will be a new In-Row Cooling solution to replace a failing HVAC solution.</td></tr>
<tr><td>Capital Contributions</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td>Start Date: January 2023</td><td colspan="2">In-Service Date: December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">There is a medium risk to completion. While this plan is part of business continuity, busyness can sometimes deflect these to future years. This is mitigated by evaluating the current solution in terms of business continuity and carving out time as necessary</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="4">B. Evaluation Criteria and Information Requirements</td></tr>
<tr><td rowspan="3">1. Efficiency, Customer Value, Reliability</td><td colspan="3">a) Investment Driver

This project is driven by ensuring continuity of technology platforms.</td></tr>
<tr><td colspan="3">b) Good Utility Practice

This is part of the overall business continuity plan.</td></tr>
<tr><td colspan="3">c) Investment Priority

High: Having a current, practical, and relative DR program is critical to business risk mitigation and required as part of the legislated Cyber Security Framework. The 2023 focus is required to be completed in order to ensure the continuity of the system.</td></tr>
</table>

	d) Analysis of Project and Alternatives This solution is internal, but outsourced solutions are evaluated. Disaster Recovery plans are not something that can be left undone. OEB regulations are required. Any system improvements are not wholesale in nature in this program.
2. Safety	Not applicable.
3. Cyber Security, Privacy	Cyber security and privacy are part of all design and development processes.
4. Co-ordination, Interoperability	Not Applicable.
5. Environmental Benefits	Not Applicable.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis is based on lifecycle expectations as provided by manufacturers, along with historical data of usages. Consideration is not given to run to failure as disaster recovery solutions are best practice and a regulated part of the OEB Cyber Security Framework.
Business Case	As per Chapter 5 of the filing requirements, this project does not “substantially exceed” the materiality threshold requiring the filing of a business case.

	CAPITAL PROJECT SUMMARY SHEET **GENERAL PLANT**	**Project Number(s):**	IT35
		Project Name:	Business Technology Improvements
		2023 Budget:	$435,000

A. General Information on the project/program

Project Summary

This capital project reflects the 10 year roadmap for technology solutions which introduces functional business improvements over the course of multiple years. It introduces new business functionality solutions across multiple platforms, as opposed to implementing a wholesale replacement of the primary ERP and related applications, including SAP.

The Business Technology Improvements project is a multi-year plan to introduce these new technology solutions. Under this capital project solutions will be developed or implemented that form the primary business system functions. It will leverage the existing, core SAP ERP solution and design, develop, and implement various functional improvements in SAP and related or integrated systems. The focus will be on functional and operational business system improvements. The approach is to take on smaller, focused projects that respond to customer experience and or business needs that can be satisfied with the implementation of new or new to Bluewater Power technology.

In 2023, Bluewater Power will focus on three specific projects. The first is to develop our Smart Data hub solution. This hub will centralize datasets from disparate sources and allow for more accurate and efficient corporate and regulatory reporting in addition to enabling other business functions. This solution will underpin a number of projects on our multi-year solution development roadmap. It will be an internally developed solution and is expected to cost $150,000.

The second project is to implement a new integrated communications solution to better interact with customers, business partners, employees, and other stakeholders. The existing solution was originally implemented in 2002 and has a growing number of limitations. The new solution will integrate with our customer information and outage management systems, accommodate social media management, enable SMS services and allow for more flexible change and solution management. This project will cost $230,000.

The third project will start a second phase of Supply Chain upgrades that will bring further automation and management of inventory. In 2023 this is expected to cost $55,000

Where possible, we will utilize Bluewater Power staff to carry out these developments.

Spending for this project is shown in the chart below:

<table>
<tr><td colspan="2"></td><td colspan="2">
<table>
<tr><th></th><th>2022 Bridge</th><th>2023 Test</th></tr>
<tr><td>Business Technology Improvements</td><td>280,000</td><td>435,000</td></tr>
</table>
In 2022, the following was spent in Business Technology Improvements:
The Supply Chain function in SAP (called Materials Management) was upgraded to include Material Requirement Planning (MRP). With a goal to improve ordering capabilities and assure the right quantities of goods are in stock and ordered, Bluewater Power can now make use of SAP's Material Requirement Planning (MRP) functionality. This allows Bluewater Power to calculate and determine stock levels from past usage, Mins/Max determination and future requirements planned in reservations. The SAP system now checks the stock levels of respective materials and generates a procurement proposal, which can be converted to a purchase requisition or order.
</td></tr>
<tr><td>Capital Contributions to a Transmitter</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td>Start Date: January 2023</td><td colspan="2">In-Service Date: December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">There is a medium risk to completion. While this plan is part of business continuity, busyness can sometimes deflect these to future years. This is mitigated by the need to respond to customer feedback.</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="4">B. Evaluation Criteria and Information Requirements</td></tr>
<tr><td rowspan="4">1. Efficiency, Customer Value, Reliability</td><td colspan="3">a) Investment Driver
This project is driven by advancing customer and business functions.</td></tr>
<tr><td colspan="3">b) Good Utility Practice
The focus of this project is customer value and employee efficiency.</td></tr>
<tr><td colspan="3">c) Investment Priority
Medium: The Smart Data Hub is critical to functions like Green Button but the deadline for other integrations is of medium priority. The communications platform is a medium priority.</td></tr>
<tr><td colspan="3">d) Analysis of Project and Alternatives</td></tr>
</table>

	There is limited consideration of alternatives, because technology changes rapidly and we must respond to ensure satisfaction in the customer experience and efficiency in business process.
2. Safety	Not applicable.
3. Cyber Security, Privacy	Cyber security and privacy are part of design and development processes.
4. Co-ordination, Interoperability	Not Applicable.
5. Environmental Benefits	A better customer experience will enable higher uptake for e-billing. This reduces the number of pages of paper that need to be printed.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: GENERAL PLANT	
Results of Quantitative and Qualitative Analyses	Analysis of these projects includes the ability to provide better services to customers and increased efficiencies to business function. Doing nothing is considered, however, Bluewater Power would not be responsive to customer engagement responses and not continuing projects of this nature would soon place Bluewater Power too far behind to practically catch up to rapidly changing technology expectations.
Business Case	As per Chapter 5 of the filing requirements, this project does not “substantially exceed” the materiality threshold requiring the filing of a business case.

CAPITAL PROJECT SUMMARY SHEET
SYSTEM ACCESS

Project Number(s):	UT11
Project Name:	New Connections, Upgrades, Subdivisions
2023 Budget:	$ 2,110,000

A. General Information on the project/program

Project Summary

Bluewater Power budgets an annual amount to cover the costs required to install underground and overhead distribution systems to provide service as needed to residential, commercial, and industrial developers.

Bluewater continually adds new residential and commercial customers as required in order to meet ongoing demand. New connections include the following:

- New subdivision and subdivision expansions
- New residential services
- New commercial/industrial services

Bluewater's customer connection expenses have varied with market conditions. The anticipated customer connection costs for 2023 are based known subdivision and commercial projects plus historical averages for new connections.

In 2023, approximately 10% of the budget is estimated for 138 new residential connections. The remaining 90% of the budget is for commercial upgrades and connections, as well as development work. These approximate values are shown in the chart, below.

2023 Budget Breakdown ($)

	2023 (budget)
New residential connections	207,600
Commercial upgrades and connections, development work	1,902,400
Total	2,110,000

Costs for the New Connections, Upgrades, Subdivisions budget and forecast capital contributions can be found in the chart, below.

Bluewater Costs ($)

	2017	2018	2019	2020	2021	2022 (budget)	2023 (budget)
Gross Cost	776,707	924,273	1,264,310	1,246,001	1,832,038	2,000,000	2,110,000
Capital Contribution	204,153	364,309	330,871	481,628	229,470	1,000,000	1,000,000
Bluewater Power Cost	572,554	559,964	933,439	764,373	1,602,568	1,000,000	1,110,000

<table>
<tr><td>**Capital Contributions to a Transmitter**</td><td colspan="2">Not applicable.</td></tr>
<tr><td>**Customer Attachments and Load**</td><td colspan="2">Not applicable.</td></tr>
<tr><td>**Project Dates and Expenditure Timing**</td><td>**Start Date:** January 2023</td><td>**In-Service Date:** December 2023</td></tr>
<tr><td>**Risks to Completion**</td><td colspan="2">Resource availability to match customers' requested in-service dates is the biggest risk to completion. Availability of resources will need to be co-ordinated with overhead, underground and demand-driven planned projects.

The mitigation plan is to ensure close co-ordination between engineering and operations staff with these projects by securing resources both internal and external (if required) to ensure completion by the requested in-service dates.

New connections typically involve the installation of new, or the modification of existing, electrical equipment that is used to supply subdivisions, as well as commercial or industrial developments. It also includes any work associated with upgrading existing infrastructure to meet the requirements of any new proposed loads. Bluewater's Conditions of Service outlines the capital contributions and expansion deposits required for these installations.

Bluewater Power is obligated to connect new customers in accordance with the *Electricity Act, 1998*, as well as its distribution license (ED-2002-0517). This expense is non-discretionary and market conditions cause the expenditure to vary from year to year. Our information is obtained through direct discussions with developers, consulting engineers and monthly Sarnia Lambton Utilities Co-ordination Program meetings hosted by the City of Sarnia where upcoming or existing projects are reviewed for our distribution territory.</td></tr>
<tr><td>**Total Capital and O&M Costs Associated with REG Investments**</td><td colspan="2">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>**Leave to Construct Approval**</td><td colspan="2">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="3">**B. Evaluation Criteria and Information Requirements**</td></tr>
<tr><td rowspan="3">**1. Efficiency, Customer Value, Reliability**</td><td colspan="2">**a) Investment Driver**

This projects is mandatory in nature to addresses customer value, economic development, and service reliability.</td></tr>
<tr><td colspan="2">**b) Good Utility Practice**

Any expansion of overhead or underground infrastructure will increase reliability to customers by strengthening and reconfiguring the distribution system.</td></tr>
<tr><td colspan="2">**c) Investment Priority**

The priority of this program is high; it is a mandatory program.</td></tr>
</table>

	d) Analysis of Project and Alternatives No alternatives have been considered; new development must be supplied service upon request.
2. Safety	No direct implication to safety.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Co-ordination will be required with the developers and consulting engineers for requests to either install new infrastructure or modify any existing installations.
5. Environmental Benefits	Not applicable.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: SYSTEM ACCESS	
Factors Relating to Customer Preferences	This project is a direct result of customer and developer requests for the installation of new services for residential, commercial or industrial developments.
Factors Affecting the Final Cost	The final cost will be affected by the size of the actual number of new customers and the rate class of new customer group.

<table>
<tr><td>BLUEWATER POWER
DISTRIBUTION CORPORATION</td><td>CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL</td><td>Project Number(s):
Project Name:
2023 Budget:</td><td>UT 5; 16
Petrolia ($208,000);
Watford ($208,000)
$416,000</td></tr>
<tr><td colspan="4">A. General Information on the project/program</td></tr>
<tr><td>Project Summary</td><td colspan="3">Bluewater budgets for upgrades in Petrolia and Watford, which are municipalities within its service territory.
In 2023, Bluewater plans to extend 27.6 kV feeders to convert 8 kV facilities to the 27.6 kV system within these municipalities. These projects update deteriorated assets in Petrolia and Watford, which are reaching end of useful life.
The benefits of the program include:
• Overall system kilowatt (kW) peak reductions
• Improved transformer efficiencies at the higher distribution voltage level
• Lower system line losses as a result of operating at a higher distribution voltage
• Lower risk of failures due to the replacement of deteriorated 8kV assets past useful life
• Reduced maintenance costs by removing 8kV equipment
• Increased capacity of the 27.6kV feeders to accommodate residential load creep as well as load increases from future emerging commercial/industrial businesses (where applicable)
• The feeder extensions increase reliability and security of supply</td></tr>
<tr><td>Capital Contributions to a Transmitter</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">No new customer connections. Existing customers to be transferred to the 27.6 kV feeder upon completion.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td>Start Date:
January 2023</td><td colspan="2">In-Service Date:
December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">Availability of resources to co-ordinate with overhead, underground and demand driven projects. The mitigation plan is close co-ordination with these projects and securing resources (both internal and external) to ensure completion.</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
</table>

B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment driver is reliability.
	b) Good Utility Practice Customers will benefit from improved reliability options with the conversion of 8 kV facilities to the new 27.6 kV feeder based on up to date infrastructure configurations that would include new automation that is typically associated with new 27.6 kV feeders. This project aligns with customers' preferences regarding increased reliability.
	c) Investment Priority The priority of this project is high as it is extending 27.6 kV feeders in a multi-phase program to convert 8 kV facilities to the 27.6 kV system where assets are past their useful life.
	d) Analysis of Project and Alternatives Limited consideration. Main operating voltage level is 27.6 kV, the 8 kV has reached its end of useful life.
2. Safety	In converting the 8 kV overhead infrastructure, any equipment that has reached its end of useful life (i.e. such as poles, or cross-arms etc.) will be eliminated from the system increasing overall safety.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Limited co-ordination is required. Any third party assets located on the poles will require some coordination with the third party to transfer/relocate their infrastructure to the new pole.
5. Environmental Benefits	Limited impact.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power follows best utility practices and CSA standards for asset lifecycle optimization. Distribution assets are inspected on a 3 year cycle for urban areas and a 6 year cycle for rural areas.
	Asset Condition Relative to Typical Lifecycle Typical useful life of pole mount and pad-mount transformers is 40 years, wood poles is 45 years. Assets installed on the 8kV system are in the range

	of 60 to 70 years old and were installed dating back sometime in 1950s timeframe.
	Number of Customers Impacted The number of customers affected depends on the affected transformers and the number of transformers converted in a defined area. Typically in the range of 20 to 30 customers will be affected per transformer converted.
	Quantitative Customer Impact and Risk Customer impact depends on the location of the transformer and the customers connected. In a residential area, the number of customers impacted might be as many as 30 at a time. For a commercial area, there may only be one customer impacted at a time but that customer will be without power while that transformer is out of service and converted. The duration of the outage varies and can take up to 4 hours to replace a transformer.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by minimizing the risk of pole, transformer failure and public safety. If a failure were to occur the outage would be unplanned and will likely have a greater negative impact to the customers and their facility.
	Value of Customer Impact Equipment failure has a high customer impact due to power outages. The failure could also pose a public risk due to a possible oil leak. The cost of a failure ranges from medium to high, depending on the area being serviced (residential or commercial) and when the outage occurs (regular hours or after hours on overtime). Outages are very disruptive to all customer classes. Generally, residential customers find outages a nuisance and these are a lower impact but now we are seeing that some residential customers are now working from home or they carry on their business from home, making an outage impact greater. Generally, GS<50 customers will experience medium impacts on their ability to carry out business. Where GS>50 customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Other planned work having a higher priority such as completion of new customer connections. This may have an impact on scheduling a line extension conversion project, a typical conversion project may take up to 8 weeks to complete. Weather can lead to delays as well to schedule the planned project work (at the start and during the project), weather issues can create unsafe work conditions for workers.
Impact on System O&M Costs	Annual operating and maintenance cost may be reduced due to fewer outages as related to newer installed infrastructure.

Impact on Reliability and Safety Factors	Operating a system to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures, as well possible damage to public/private property. Proactive replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage.
Analysis of Project Benefits, Costs, Alternatives, and Timing	There are two approaches that one can take, either a reactive replacement approach or the preferred a proactive replacement method. The reactive approach leads to worsening reliability, increased public safety risks and environmental concerns. Wood pole failures and transformer failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. Additionally, transformer failures could result in oil leaks and possible environmental damages. The reactive approach leads to an inefficient operation, strain on resources and inflated inventory levels to mitigate the risk of running out of stock, all contributing to higher O&M costs. A proactive approach will mitigate the risk of unexpected failures, improves safety, maintains reliability and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notification. It assists with operational resources, as work can be planned and inventory can be planned based on the scheduled project size. While labour costs associated for the conversion project can be controlled/predicted during regular hours versus an unexpected outage that takes place after regular business hours.
“Like for Like” Renewal	This project is not considered a ‘like for like’ project, a complete pole line design and rebuild will be required to meet the required clearance requirements at the 27.6 kV level.

	CAPITAL PROJECT SUMMARY SHEET **SYSTEM RENEWAL**	**Project Number(s):**	UT7
		Project Name:	4 kV Lines Rebuild/ Load Conversion
		2023 Budget:	$210,000

A. General Information on the project/program

Project Summary

Bluewater Power has a regular program of converting 4 kV facilities to the 27.6 kV system. These projects update deteriorated assets, which are reaching end of useful life.

The benefits of the program include:

- Overall system kilowatt (kW) peak reductions
- Improved transformer efficiencies at the higher distribution voltage level
- Lower system line losses as a result of operating at a higher distribution voltage
- Lower risk of failures due to the replacement of 4 kV assets past useful life
- Reduced maintenance costs by removing 4 kV equipment
- Increased capacity of the 27.6 kV feeders to accommodate residential load creep from the installation of electric vehicle chargers, as well as load
- Increases from future emerging businesses (where applicable)
- Increased operating flexibility
- More streamlined spare parts inventory

In 2023, Bluewater plans to convert 4 kV feeders out of its Municipal Substation #10, located at Cromwell Street and Forsyth Street in Sarnia. Bluewater plans to extend 27.6 kV lines (approximately 0.5 km) and convert 8 to 10 transformer banks to 27.6 kV. Additionally, Bluewater is replacing infrastructure under project UT 5 Petrolia and UT 16 Watford in 2023, as described in a separate Capital Project Summary Sheet.

The five-year budget for this program reflects an increase in focus as the assets have reached their end of useful life. Based on the information obtained for failures in the area, at this time it has been determined that the allocated amount would be sufficient to replace the existing infrastructure on a gradual basis. Until it is deemed that failures are critical, then additional funds may be requested.

Spending for this project in the Bridge and Test Years is shown in the chart below:

	2022 Bridge	2023 Test
4 kV Lines	200,000	210,000

Capital Contributions to a Transmitter	No capital contributions or cost recovery will be made to the transmitter.
Customer Attachments and Load	No new customer connections. Existing customers to be transferred to the 27.6 kV feeder upon completion.
Project Dates and Expenditure Timing	**Start Date:** January 2023 **In-Service Date:** December 2023
Risks to Completion	Availability of resources to co-ordinate with overhead, underground and demand driven projects. The mitigation plan is close co-ordination with these projects and securing resources (both internal and external) to ensure completion.
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main driver for the project is customer reliability. Other drivers include increasing operating flexibility and effectiveness. The project will improve transformer efficiencies and lower system line losses at the higher distribution level. In addition, since 4 kV assets have reached their end of useful life, it will lower the risk of failures and reduce maintenance costs by removing 4 kV equipment.
	b) Good Utility Practice Customers will benefit from improved reliability options with the conversion of 4kV facilities to the new 27.6kV feeder. This project aligns with customer preferences regarding increased reliability.
	c) Investment Priority The priority of this project is medium.
	d) Analysis of Project and Alternatives Most of the 4 kV overhead infrastructure installed is at least 60 to 70 years old and has reached its end of useful life. With ongoing conversion to 27.6 kV it would eventually reduce load off of the Municipal Substations (MS) therefore potentially eliminating some 4 kV MS in the future.
2. Safety	In converting the 4 kV overhead infrastructure, any equipment that has reached its end of useful life (i.e. such as poles, or cross-arms etc.) will be eliminated from the system increasing overall safety. Planned

	replacements avoid the risk of catastrophic failures leading to possible safety and the threat to the environment due to an insulating oil leak from a transformer.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Limited co-ordination is required. Any third party assets located on the poles will require some coordination with the third party to transfer/relocate their infrastructure to the new pole.
5. Environmental Benefits	Planned replacements avoid the risk of catastrophic failures leading to possible safety and the threat to the environment due to an insulating oil leak from a transformer.
6. Conservation and Demand Management	With improved transformer efficiencies at the higher distribution voltage level, overall system Kilowatt (kW) peak will be reduced. This will result in lower system line losses as a result of operating at a higher distribution voltage.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power follows best utility practices and CSA standards for asset lifecycle optimization. Distribution assets are inspected on a 3 year cycle for urban areas and a 6 year cycle for rural areas.
	Asset Condition Relative to Typical Lifecycle Typical useful life of pole mount and pad-mount transformers is 40 years, and wood poles is 45 years. Assets installed on the 4 kV system are in the range of 60 to 70 years old.
	Number of Customers Impacted The number of customers affected depends on the affected transformers and the number of transformers converted in a defined area. Typically in the range of 20 to 30 customers will be affected per transformer converted.
	Quantitative Customer Impact and Risk Customer impact depends on the location of the transformer and the customers connected. In a residential area, the number of customers impacted might be as many as 30 at a time. For a commercial area, there may only be one customer impacted at a time but that customer will be without power while that transformer is out of service and converted. The duration of the outage varies and can take up to 4 hours to replace a transformer.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by minimizing the risk of pole, transformer failure and public safety. If a failure were to occur the outage would be unplanned and will likely have a greater negative impact to the customers and their facility.
	Value of Customer Impact Equipment failure has a high customer impact due to power outages. Failures could also pose a public risk due to a possible oil leak. The cost of a failure ranges from medium to high, depending on the area being serviced (residential or commercial) and when the outage occurs (regular hours or after hours on overtime).

	Outages are very disruptive to all customer classes. Historically, a residential outage is typically of low impact. But, with increasing numbers of residential customers working from home, residential outage impacts have increased. Generally, General Service Less than 50 kW customers will experience medium impacts on their ability to carry out business. General Service Greater than 50 kW customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Timing may be impacted by other planned work having a higher priority, such as the completion of new customer connections. This may have an impact on scheduling a conversion project; a typical conversion project may take up to 8 weeks to complete. Weather can also lead to delays to schedule the planned project work (at the start and during the project); additionally, weather issues can create unsafe work conditions for workers.
Impact on System O&M Costs	Annual operating and maintenance costs may be reduced due to fewer outages as related to newer installed infrastructure.
Impact on Reliability and Safety Factors	Operating a system to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures, as well possible damage to public/private property. Proactive replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage.
Analysis of Project Benefits, Costs, Alternatives, and Timing	There are two approaches to replacement: a reactive replacement or the preferred proactive replacement method. The reactive approach leads to worsening reliability, increased public safety risks, and environmental concerns. Wood pole failures and transformer failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. Additionally, transformer failures could result in oil leaks and possible environmental damages. The reactive approach leads to an inefficient operation, strain on resources, and inflated inventory levels to mitigate the risk of running out of stock, all of which contribute to higher O&M costs. Conversely, a proactive approach mitigates the risk of unexpected failures, improves safety, maintains reliability, and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notification. It assists with operational resources, as work can be planned and inventory can be planned based on the scheduled project size.

	Labour costs associated with the conversion project can be controlled and predicted during regular hours versus an unexpected outage that takes place after regular business hours.
"Like for Like" Renewal	This project is not considered a 'like for like' project. A complete pole line design and rebuild will be required to meet the required clearance requirements at the 27.6 kV level.

	CAPITAL PROJECT SUMMARY SHEET **SYSTEM RENEWAL**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT14 Cross Arm/Cap & Pin Insulator Replacement Program $153,000

A. General Information on the project/program

Project Summary

Bluewater Power's distribution facilities are primarily comprised of wood poles, wood cross-arms, and porcelain insulators. These designs have served the utility industry well; however, with age it is apparent that the weak link in the structural elements of the design is the wood cross arm, as well as in the porcelain insulators that support the conductor.

The condition of cross-arms is affected by the following:
- the quality of the original materials and treatment;
- insect damage;
- splitting due to weathering or loads; and
- rot or insect infestations of the material.

Bluewater Power conducts visual inspections of the cross-arms to determine whether they are adequate to remain in service. Cross-arms are replaced at the end of their useful life as determined due to factors noted above.

Defects in insulators are not as easily identifiable. Defects in insulators can lead to mechanical failures with the potential for overhead conductors to come into contact with each other or falling on the ground thus presenting safety risk to public, resulting in damage to equipment, potential safety hazards and a subsequent outages. Further, defective insulators pose a safety risk to staff working on overhead poles. Bluewater Power has determined that certain 35 kV Ohio Brass horizontal post insulators manufactured from porcelain can fail prematurely by breaking off. Bluewater Power began to use a 35 kV epoxy style insulator in the early 1990s to replace porcelain.

Any outages resulting from the failure of a cross arm or an insulator will usually result in the interruption of power on the entire feeder, which typically supplies several thousand customers. While a momentary feeder outage can be restored automatically, any cases requiring repairs can create prolonged outages.

Historically, Bluewater Power did not track the age of its porcelain insulators. Therefore, Bluewater Power believes that it is prudent to replace all of its porcelain insulators with epoxy style insulators in conjunction with cross-arm replacements and other programs as described below.

To date, Bluewater Power has replaced porcelain insulators and cross-arms on critical circuits that serve critical customers. The current practice is to change insulators on existing poles where it has been determined that existing poles have not reached their end of useful life. It is common for these assets to be replaced in conjunction with Bluewater's 4 kV and 8 kV voltage conversion programs, with pole replacements and with system expansions.

Bluewater Power has selected a polymeric insulator (the insulator is lighter in weight and installation time is quicker, which is more cost effective). When new wooden cross-arms are installed on existing poles (where the pole will not be replaced), this allows the remaining useful life of the pole to be utilized until it is replaced due to end of life. At which point, once the pole is at end of life, the entire pole plus all its components will be changed (noting the typical useful life of a wooden cross-arm is half the life of a wood pole).

Visual inspections have determined that increased emphasis must be placed on the replacement of cross arms and insulators due to age of infrastructure and observed deterioration. Therefore, a proactive replacement program of cross arms and insulators is budgeted on an annual basis and will be staged for replacement over the next several years.

The budget for this program is paced based on a 5-year average of actual spending. Spending for this project is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Cross Arm/Cap and Pin Insulator	189,407	114,276	62,235	184,604	155,826	150,000	153,000

Capital Contributions to a Transmitter	No capital contributions or cost recovery will be made to the transmitter.	
Customer Attachments and Load	No new customer connections. Existing customers to be transferred to the 27.6 kV feeder upon completion.	
Project Dates and Expenditure Timing	**Start Date:** January 2023	**In-Service Date:** December 2023

Risks to Completion	Availability of resources and ability to co-ordinate outages may hinder the progress of these projects. The mitigation plan is to monitor the projects closely and secure external resources if required to complete the work.
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment drivers are safety, reliability, and customer value.
	b) Good Utility Practice A secure and reliable overhead distribution system will improve the overall system operation by reducing avoidable outages and ensuring reliable distribution of power to customers. The new epoxy/polymeric insulators have a stronger reliability performance. The replacement components are light weight, high strength, and have a strong explosion protection. This ensures that new components have better ability to withstand adverse weather conditions. This project supports customers' preferences for increased reliability.
	c) Investment Priority The priority of this project is high where replacement is focused in areas where assets have reached their end of useful life, reducing avoidable outages and ensuring reliable distribution of power to customers. Failure of porcelain insulators can be a leading cause of power outages.
	d) Analysis of Project and Alternatives Existing equipment can remain in service; however, it may compromise reliability and safety. Planned replacement of porcelain insulators and cross-arms rather than replacement at the time of catastrophic failure can usually be organized as part of regular work and therefore not subject to overtime premiums. Benefits to the customer include continued, reliable and safe delivery of electricity. Doing nothing or run to failure and repairing components on a reactive basis is considered. Based on historical trends industry wide, porcelain devices have been assessed as having a high probability of failure. The result of a failure could impact public and worker safety and will have a negative impact on system reliability.
2. Safety	Safety is the main factor in replacing defective overhead line equipment. Porcelain materials have characteristics that could explode during a failure, any potential defects can also create a live point of contact that poses a safety risk to staff working on overhead poles and to the public.

3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Co-ordination would be required with customer's if/when outages impact customers. In addition when applicable work is coordinated with other scheduled pole replacement or conversion projects.
5. Environmental Benefits	Not applicable.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power follows best utility practices and CSA standards for asset lifecycle optimization. Distribution assets are inspected on a 3 year cycle for urban areas and a 6 year cycle for rural areas. Bluewater Power`s main objective is to continually maintain a strong reliability record by minimizing the frequency and duration of unplanned outages. To mitigate any possibly public safety risk Bluewater Power will be replacing porcelain insulators with epoxy/polymeric type insulators as well as wood cross-arms identified as having reached their end of useful life. Prioritization will be based on annual asset visual inspections and will be coordinated with other scheduled capital upgrades.
	Asset Condition Relative to Typical Lifecycle Typical useful life of a wood cross-arm is 20 to 25 years -- approximately half the life of a wood pole. While porcelain insulators are in deteriorating electrical condition subject to cracking and sudden failure, the risk of failure could be catastrophic. There are not repair options for porcelain insulators; the assets must be replaced to eliminate the risk.
	Number of Customers Impacted Any outages resulting from the failure of a cross arm or an insulator will usually result in the interruption of power on the entire feeder, which typically supplies several thousand customers (which could be residential, <50 kW and >50 kW customers). While a momentary feeder outage can be restored automatically, any cases requiring repairs can create prolonged outages.
	Quantitative Customer Impact and Risk Customer impact depends on the location of failure and all of the customers connected to that feeder. A feeder typically supplies several thousand customers which range from a combination of residential, <50 kW and >50 kW customers. While a momentary feeder outage can be restored automatically, any cases requiring repairs can create prolonged outages. Depending on the severity of the failure, some customers (in the area of the failure) could be without power from anywhere for 4 to 6 hours while repairs are completed.
	Qualitative Customer Impact and Risk

	Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by minimizing the risk of pole, cross-arm, insulator failure and public safety. If a failure were to occur, the outage would be unplanned and will likely have a greater negative impact to the customers and their facility.
	Value of Customer Impact Equipment failure has a high customer impact due to power outages. A porcelain insulator failure could also pose a serious public safety risk due to the explosive nature of these devices. The cost of the unexpected failure of the insulator is relatively low; however, the cost of customer disruption could be very costly due to economic loss as a result of an unplanned outage. The cost of a failure ranges from medium to high, depending on the area being serviced (residential or commercial) and when the outage occurs (regular hours or after hours on overtime). Outages are very disruptive to all customer classes. Generally, residential customers find outages a nuisance and these are a lower impact but we are now seeing that some residential customers are now working from home or they carry on their business from home, making an outage impact greater. Generally, GS<50 customers will experience medium impacts on their ability to carry out business. Where GS>50 customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Other planned work having a higher priority such as completion of new customer connections may have an impact on scheduling replacements. These replacements are usually scheduled with other capital upgrades (i.e. wood pole replacements or pole mount transformer replacements) Weather can lead to delays as well to schedule the planned project work weather issues can create unsafe work conditions for workers.
Impact on System O&M Costs	Running to failure or a reactive approach will escalate O&M costs over time. At the time of failure, mitigating the immediate effect of the outage on customers will be an O&M expense. This may occur outside of normal business hours and require unplanned overtime at an increased expense. Planned replacement work would benefit from economies of scale, as multiple scheduled projects would be combined resulting in reduced O&M costs.
Impact on Reliability and Safety Factors	Operating a system to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures, as well possible damage to public/private property. Proactive replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage.
Analysis of Project Benefits, Costs,	There are two approaches that one can take, either a reactive replacement approach or the preferred proactive replacement method.

Alternatives, and Timing	The reactive approach leads to worsening reliability, increased public safety risks and environmental concerns. Porcelain insulator and cross-arm failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. The reactive approach leads to an inefficient operation, strain on resources and inflated inventory levels to mitigate the risk of running out of stock. All contributing to higher O&M costs. With a proactive approach, it will mitigate the risk of unexpected failures, improves safety, maintains reliability and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notification. It assists with operational resources, as work can be planned and inventory can be planned based on the scheduled project size. While labour costs associated for the conversion project can be controlled/predicted during regular hours versus an unexpected outage that takes place after regular business hours.
“Like for Like” Renewal	Insulators and cross-arms make up a critical part of the distribution system and most of the replacements are completed on a “like for like” basis with new epoxy/polymeric type insulators as well as wood cross-arms installed that do not come at a significant extra cost. The new material installed will provide enhanced performance and reliability and do not directly address future planning objectives.

CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL

Project Number(s): UT 15
Project Name: Wood Pole Replacement
2023 Budget: $1,957,000

A. General Information on the project/program

Project Summary

This program involves replacing wood poles that have deteriorated to the point where they have reached the end of their useful life, as determined by visual inspections or resistograph test results.

Bluewater Power has approximately 15,500 poles within its distribution system.

Approximately one-third (4,400) of Bluewater Power's poles are targeted for visual inspection each year. Visual inspections may identify a rotten pole for replacement or may identify a pole for further resistograph analysis.

Wood poles are also tested using a resistograph tool where a non-destructive resistance test is performed to quantify the structural integrity of the pole at ground level. This test measures the degree of decay and cavity of a wood pole.

Bluewater plans to replace approximately 190 wood poles in 2023 as part of this program. This quantity is in addition to wood poles installed under other programs (i.e. voltage conversion programs, etc.). Other assets identified from visual inspections that are in need of replacement, such as guy wires, insulators, and transformers, may be replaced in addition to the pole, as part of this wood pole replacement program.

At this pace, approximately 1.2% of wood poles are being replaced per year, which, not accounting for wood poles installed under other programs, would replace all poles every 82 years.

Spending on the Wood Pole Replacement Program is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Wood Pole Replacement Program	1,911,268	1,706,437	2,040,526	2,316,330	1,563,010	1,900,000	1,957,000

Bluewater has paced spending in the Bridge and Test Years at a similar level to the 5-year historical average.

Capital Contributions to a Transmitter

No capital contributions or cost recovery will be made to the transmitter.

Customer Attachments and Load

No new customer connections. Existing customers to be transferred once poles are replaced.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2023

Risks to Completion	Risks to completion are minimal. This project is part of a program that is successfully executed each year. The availability of resources (internal or an external contractor) is sufficient to complete this project.
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment drivers are safety and reliability.
	b) Good Utility Practice Limited engagement with customers is required as most poles are replaced like-for-like.
	c) Investment Priority This is a high priority project. Bluewater's priority of this project is to proactively replace poles found in poor condition through testing. The strategy is to replace assets before they reach a critical condition where reliability and safety may be compromised.
	d) Analysis of Project and Alternatives Limited consideration. Poles in need of replacement from pole testing must be scheduled to be replaced to reduce any potential future failures.
2. Safety	Poles that have reached their end of life are at high risk of failure during adverse weather conditions. This program replaces poles that are at risk.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Limited co-ordination is required. Most poles are replaced like-for-like without affecting adjacent pole lines. Any third-party assets located on the pole will require some coordination with the third party to transfer/relocate their infrastructure to the new pole.
5. Environmental Benefits	Not applicable.
6. Conservation and Demand Management	Limited impact.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power follows best utility practices and CSA standards for asset lifecycle optimization. Distribution assets are inspected on a 3 year cycle for urban areas and a 6 year cycle for rural areas. Poles are only identified for replacement when tested where the degree of cavity and decay results indicates that a pole requires immediate attention.
	Asset Condition Relative to Typical Lifecycle

	Typical useful life of wood poles is 45 years. These assets have deteriorated to the point where they have reached the end of their useful life based on test results from pole testing. Wood pole assets installed within the 4kV system are in the range of 60 to 70 years old.
	Number of Customers Impacted The number of customers affected depends on the poles identified to be replaced and the number of transformers serviced off of these replaced poles in a defined area.
	Quantitative Customer Impact and Risk Bluewater Power proactively replaces poles before failure occurs, therefore customers impacted is not available. A possible single pole failure may result in an unplanned interruption that could affect upwards to 5,000 customers depending on the pole location and pole type.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by minimizing the risk of pole failures and for public safety.
	Value of Customer Impact A pole failure will result in an unplanned outage which has a high customer impact, in addition it could pose a public safety risk as the pole could fall over which will result in energized overhead lines ending up on the ground. The cost of a failure ranges from medium to high, depending on the area being serviced (residential or commercial) and when the outage occurs (regular hours or after hours on overtime). Outages are very disruptive to all customer classes. Generally, residential customers find outages a nuisance and these are a lower impact but now we are seeing that some residential customers are working from home or they are running their business form home, making an outage impact greater. Generally, GS<50 customers will experience medium impacts on their ability to carry out business. Where GS>50 customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Weather can lead to delays or create unsafe work conditions. Typically, only emergency work and construction work related to new connection requests would take priority over pole replacements.
Impact on System O&M Costs	Poles that have reached their end of useful life typically support older distribution assets. With the upgrade of these poles, they will also will also address any older assets in need of replacement. Therefore, reducing outage times and any additional future O&M costs.
Impact on Reliability and Safety Factors	Operating to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures, as well possible as damage to public/private property and possibly create a public safety concern. Proactive

	replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage, if required.
Analysis of Project Benefits, Costs, Alternatives, and Timing	There two approaches that one can take, either a reactive replacement approach or the preferred proactive replacement method. The reactive approach leads to worsening reliability as well as increased risks to public safety. Wood pole failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. The reactive approach leads to an inefficient operation, strain on resources and inflated inventory levels to mitigate the risk of running out of stock - all contributing to higher O&M costs. With a proactive approach, it will mitigate the risk of unexpected failures, improves safety, maintains reliability and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notifications. It assists with operational resources, as work and inventory can be planned based on the project size. While labour costs associated for pole replacement projects can be controlled/predicted during regular hours versus an unexpected outage that takes place after regular business hours.
“Like for Like” Renewal	Poles are considered an integral part of the distribution system and most of the pole replacements are completed on a “like for like” basis. In areas where multiple poles are identified in need of replacement on one section of a street or in a section of a neighbourhood, then a complete pole line design/rebuild may be required. If multiple poles are replaced within a block, the extra benefits obtained designed to (such as increased pole heights) will assist in meeting future planning objectives at a minimal incremental cost.

CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL

Project Number(s): UT18

Project Name: Unforeseen Capital Fund

2023 Budget: $175,000

A. General Information on the project/program

Project Summary

Unexpected and unforeseen capital expenditures arise during the course of the year that require an immediate response. In response, Bluewater has established an Unforeseen Capital Fund to allow issues to be addressed in a timely manner. The fund has been used to complete major repairs to power line vehicles, purchase job-specific equipment, Service Centre and Substation building upgrades. All of these items were unforeseen but required attention within the budget year.

The budget for this program is paced based on a 5-year average of actual spending. Spending for this project is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Unforeseen Capital Fund	180,328	262,327	190,325	85,072	140,876	200,000	175,000

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2023

Risks to Completion

Risk to completion is minimal. Any unforeseen projects are addressed as required.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval

This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability

a) Investment Driver

The main investment driver is reliability.

b) Good Utility Practice

Depending on the situation, it would assist with reliability providing efficiency and value to customers

c) Investment Priority

The priority of this project is high and is based on unexpected and unforeseen capital expenditures that arise during the course of the year that require an immediate response.

2. Safety	Not Applicable.
3. Cyber Security, Privacy	Not Applicable.
4. Co-ordination, Interoperability	Not Applicable.
5. Environmental Benefits	Not Applicable.
6. Conservation and Demand Management	Not Applicable.

CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL

Project Number(s):	UT21, UT22
Project Name:	27.6 kV Feeder Extensions ($372,500), 8 kV Load Conversion ($372,500)
2023 Budget:	$745,000

A. General Information on the project/program

Project Summary

Bluewater Power has a regular program of extending 27.6 kV feeders to convert 8 kV facilities to the 27.6 kV system. This multi-phase program (approximately 5 years) updates deteriorated assets in the system, which are reaching end of useful life.

The long-term plan is to eliminate the one remaining 8 kV Municipal Substation located in Sarnia that was inherited from Ontario Hydro (MS21) and associated feeders along Lakeshore Road in Sarnia.

The benefits of the program include:

- Overall system kilowatt (kW) peak reductions
- Improved transformer efficiencies at the higher distribution voltage level
- Lower system line losses as a result of operating at a higher distribution voltage
- Lower risk of failures due to the replacement of deteriorated 8 kV assets past useful life
- Reduced maintenance costs by removing 8 kV equipment
- Increased capacity of the 27.6 kV feeders to accommodate residential load creep from electronic vehicles, as well as load increases from future emerging commercial/industrial businesses (where applicable)
- The feeder extensions increase reliability and security of supply

Annual operating and maintenance cost may be reduced due to fewer outages as related to newer installed infrastructure.

Spending in the Bridge and Test Years is shown in the chart below:

	2022 Bridge	2023 Test
27.6 kV Feeder Extension	250,000	372,500
8 kV Load Conversion	0	372,500
Total	250,000	745,000

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

No new customer connections. Existing customers to be transferred to the 27.6 kV feeder upon completion.

Project Dates and Expenditure Timing

Start Date:
January 2023

In-Service Date:
December 2023

Risks to Completion

Risks to completion include the availability of resources to co-ordinate with overhead, underground and demand driven projects. The mitigation plan is close co-ordination

	with these projects and securing resources (both internal and external) to ensure completion.
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment driver is reliability.
	b) Good Utility Practice Customers will benefit from improved reliability options with the conversion of 8 kV facilities to the new 27.6 kV feeder based on up to date infrastructure configurations that would include new automation that is typically associated with new 27.6 kV feeders. Customer engagement confirms that customers value improved reliability.
	c) Investment Priority The priority of this project is medium. It is a regular program of extending 27.6 kV feeders in a multi-phase program to convert 8 kV facilities to the 27.6 kV system where assets are past their useful life.
	d) Analysis of Project and Alternatives Limited consideration. The main operating voltage level is 27.6 kV; the 8 kV in Sarnia (which was inherited from Ontario Hydro) has reached its end of useful life.
2. Safety	In converting the 8 kV overhead infrastructure, any equipment that has reached its end of useful life (i.e. such as poles, or cross-arms etc.) will be eliminated from the system increasing overall safety.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Limited co-ordination is required. Any third party assets located on the poles will require some coordination with the third party to transfer/relocate their infrastructure to the new pole.
5. Environmental Benefits	Limited impact.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: SYSTEM RENEWAL	
	Asset Performance Target and Asset Lifecycle Optimization

Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	Bluewater Power follows best utility practices and CSA standards for asset lifecycle optimization. Distribution assets are inspected on a 3 year cycle for urban areas and a 6 year cycle for rural areas.
	Asset Condition Relative to Typical Lifecycle Typical useful life of pole mount and pad-mount transformers is 40 years and 45 years for wood poles. Assets installed on the 8 kV system are in the range of 60 to 70 years old and were installed dating back sometime in 1950s timeframe.
	Number of Customers Impacted The number of customers affected depends on the affected transformers and the number of transformers converted in a defined area. Typically in the range of 20 to 30 customers will be affected per transformer converted.
	Quantitative Customer Impact and Risk Customer impact depends on the location of the transformer and the customers connected. In a residential area, the number of customers impacted might be as many as 30 at a time. For a commercial area, there may only be one customer impacted at a time but that customer will be without power while that transformer is out of service and converted. The duration of the outage varies and can take up to 4 hours to replace a transformer.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by minimizing the risk of pole, transformer failure and public safety. If a failure were to occur the outage would be unplanned and will likely have a greater negative impact to the customers and their facility.
	Value of Customer Impact Equipment failure has a high customer impact due to power outages. The failure could also pose a public risk due to a possible oil leak. The cost of a failure ranges from medium to high, depending on the area being serviced (residential or commercial) and when the outage occurs (regular hours or after hours on overtime). Outages are very disruptive to all customer classes. Generally, residential customers find outages a nuisance and these are a lower impact but now we are seeing that some residential customers are now working from home or they carry on their business from home, making an outage impact greater. Generally, GS<50 kW customers will experience medium impacts on their ability to carry out business. Where GS>50 kW customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Other planned work having a higher priority such as completion of new customer connections. This may have an impact on scheduling a line extension conversion project, a typical conversion project may take up to 8 weeks to complete. Weather can lead to delays as well to schedule the planned project work (at the start and during the project), weather issues can create unsafe work conditions for workers.

Impact on System O&M Costs	Annual operating and maintenance cost may be reduced due to fewer outages as related to newer installed infrastructure.
Impact on Reliability and Safety Factors	Operating a system to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures, as well possible damage to public/private property. Proactive replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage.
Analysis of Project Benefits, Costs, Alternatives, and Timing	There are two approaches that one can take, either a reactive replacement approach or the preferred a proactive replacement method. The reactive approach leads to worsening reliability, increased public safety risks and environmental concerns. Wood pole failures and transformer failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. Additionally, transformer failures could result in oil leaks and possible environmental damages. The reactive approach leads to an inefficient operation, strain on resources and inflated inventory levels to mitigate the risk of running out of stock, all contributing to higher O&M costs. With a proactive approach, it will mitigate the risk of unexpected failures, improves safety, maintains reliability and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notification. It assists with operational resources, as work can be planned and inventory can be planned based on the scheduled project size. While labour costs associated for the conversion project can be controlled/predicted during regular hours versus an unexpected outage that takes place after regular business hours.
“Like for Like” Renewal	This project is not considered a ‘like for like’ project, a complete pole line design and rebuild will be required to meet the required clearance requirements at the 27.6 kV level.

BLUEWATER POWER DISTRIBUTION CORPORATION	**CAPITAL PROJECT SUMMARY SHEET** **SYSTEM RENEWAL**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT24 Storm Restoration $385,000

A. General Information on the project/program

Project Summary

Bluewater Power budgets an annual amount to cover the costs required for electrical plant replacement that has occurred as a result of storm damage. Bluewater tracks storm-related costs separate from other capital upgrades. The capital budget value is an estimate of average annual costs associated with storm damage combined with practical knowledge of staff.

The budget for this program is paced based on a 3-year average of actual spending to reflect recent weather patterns. Spending for this project is shown in the chart below:

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Storm Restoration	256,390	212,537	311,998	235,969	568,753	350,000	385,000

Capital Contributions to a Transmitter

No capital contributions or cost recovery will be made to the transmitter.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: May 2023

In-Service Date: December 2023

Risks to Completion

Risk to completion is minimal. Crews are dispatched as required for any outages or equipment damage as a result of a storm.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval

This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability

a) Investment Driver

The main investment drivers are reliability, efficiency, and customer value, associated with replacements as a result of major storms.

b) Good Utility Practice

c) Investment Priority

The priority of this project is high as reliability needs to be maintained by restoring power in a safe and efficient manner for customers.

2. Safety	Safety will increase as any damaged overhead infrastructure is eliminated and replaced with new infrastructure.
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Not applicable.
5. Environmental Benefits	Not applicable.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater reuses any material that's not damaged by the storm.
	Asset Condition Relative to Typical Lifecycle Not applicable.
	Number of Customers Impacted The number of customers impacted depends on the location of the infrastructure affected by the storm.
	Quantitative Customer Impact and Risk Customer impact depends on the location of the infrastructure and the customers connected, as well as the damage to infrastructure.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability.
	Value of Customer Impact Storm restoration is required for safety. Business operations are impacted during outages, as are residential customers (such as refrigerator, freezer appliances).
Other Factors Affecting Project Timing	Timing is affected by the duration of storm and the working conditions it causes.
Impact on System O&M Costs	Annual operating and maintenance costs will be reduced as any replacements will result in fewer outages as related to newer installed infrastructure.
Impact on Reliability and Safety Factors	Storm repairs bring affected, replaced infrastructure up to today's standards.
Analysis of Project Benefits, Costs, Alternatives, and Timing	An analysis is done of the damage done to infrastructure and alternative measures are taken into consideration to reduce outage times, such as whether repairs can be made or a replacement is needed.

“Like for Like” Renewal	Replacements are made with equipment following up-to-date standards.

	CAPITAL PROJECT SUMMARY SHEET **SYSTEM RENEWAL**	**Project Number(s):**	UT26
		Project Name:	Primary Underground Cable Replacements
		2023 Budget:	$322,000

A. General Information on the project/program

Project Summary	Commencing in 2010, Bluewater Power engaged in proactive replacement of primary underground cables. The target areas are underground subdivisions where the primary cables have reached their end of useful life as a result of age and, in some instances, cable has deteriorated to the point where cable failures have occurred. To date, the majority of failures have been “ball and socket” splices that have failed (these failed splices have been replaced), and some actual cable failures have also been identified (where they have been identified, work is in progress to replace those faulted cables). The area being targeted with this program was originally installed in the early 1970s by Ontario Hydro. At that time, Ontario Hydro’s standard construction method was to direct bury the non-tree retardant primary cables without ductwork. The work was carried out by trenching and laying the cable in the trench. Bluewater Power utilizes available excavation technology by way of directional drilling to install the new underground plant. In conjunction with other utilities (i.e. Cogeco Cable TV and/or Bell Canada), the installation of duct is coordinated so that new installations are installed in a common trench as a joint effort installation. This minimizes disruption to the residential landscape. The result is a cost-effective method to improve system reliability and performance while minimizing the inconvenience on the customer. In total, approximately 65 km of direct-buried primary underground cable needs to be replaced in our territory. The budgeted amounts to-date typically results in approximately 3 km of duct and primary conductor being installed. This would mean approximately 5% per year, with the entire cable being replaced in 22 years. Based on the information obtained for cable failures, at this time it has been determined that the allocated amount would be sufficient to replace the existing cables on a gradual basis. Until it is deemed that failures in areas are critical, then additional funds may be requested. If Bluewater Power chooses the approach to defer this project, considering that the majority of these underground cables were installed within the same time frame (early 1970s), Bluewater Power runs the risk that multiple failures could occur where “pockets” of subdivisions are enduring longer power outages as a result of cable failures (possibly 4 to 10 hours or longer depending where the fault is located and if an alternate source of supply can be re-directed to the area). Bluewater Power would then be required to

react and repair a 45 year old cable temporarily until a new cable could be installed, which would mean the work would essentially need to be completed twice. Taking a proactive approach allows Bluewater Power to design/plan in advance for areas based on age or condition.

Areas currently targeted for cable and duct placement include (Subdivisions east of Murphy Rd. -- i.e. Cardiff, Coronation, Wiltshire and Twin Lakes Subdivision).

Spending for this project in the Bridge and Test Years is shown in the chart below:

	2022 Bridge	2023 Test
Primary Underground Cable Replacements	300,000	322,000

Capital Contributions to a Transmitter	No capital contributions or cost recovery will be made to the transmitter.	
Customer Attachments and Load	No new customer connections.	
Project Dates and Expenditure Timing	**Start Date:** May 2023	**In-Service Date:** December 2023
Risks to Completion	Resource availability (contract and internal) is the biggest risk to completion. Mitigation plan includes securing external resources and regular co-ordination meetings with Engineering and Operations.	
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.	
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).	

B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment drivers are reliability, efficiency, and customer value.
	b) Good Utility Practice Full duct installation and cable replacement will greatly improve reliability now and in the future to address any potential cable failures. Reliability will improve with fewer outages and if replacement is required it would take a much shorter time then for direct buried cables. From surveys, customers felt that Bluewater Power should invest in what it predicts is required to replace aging infrastructure and maintain system reliability, even if it may result in a bill increase.
	c) Investment Priority The priority of this project is high as cables have reached their end of useful life as a result of age and in some instances, cable has deteriorated to the point where cable failures have occurred. When a failure occurs, this will result in a long unplanned outage, as the location of the fault will need to be identified and a plan will need to be established on how to correct the issue. All of this could occur outside of normal business hours (on overtime hours), where costs after a failure will be significantly higher than a planned proactive cable replacement approach.
	d) Analysis of Project and Alternatives Cable injection was considered, however injection is only a temporary solution to address cables that have reached end of life. Full replacement with duct was deemed to have more of a benefit for long-term reliability for customers.
2. Safety	When directional drilling, there is always a risk of damaging other utilities as well as a slight risk to workers handling equipment and cables.
3. Cyber Security, Privacy	Not Applicable.
4. Co-ordination, Interoperability	In conjunction with other utilities (i.e. Cogeco Cable TV and/or Bell Canada), as required, the installation of duct is typically coordinated so that new installations are installed in a common trench as a joint effort installation in areas beneficial to al parties. This minimizes disruption to the residential landscape. The result is a cost effective method to improve system reliability and performance while minimizing the inconvenience on the customer.
5. Environmental Benefits	Limited impact.
6. Conservation and Demand Management	Not Applicable.

C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power’s objective is to maintain a strong reliability record and minimize the frequency and duration of power outages. In order to achieve this objective, Bluewater Power will be installing approximately 3 km of duct and primary conductor in areas where underground cables were installed within the same time frame (early 1970’s), where they have reached the end of their useful life.
	Asset Condition Relative to Typical Lifecycle Bluewater Power has approximately 65 km of direct-buried primary underground cable that needs to be replaced in our distribution territory. The budgeted amounts to-date typically results in approximately 3 km of duct and primary conductor being installed. In several areas, primary underground conductors were installed within the same time frame (early 1970s), all cables within this era have reached the end of their useful life.
	Number of Customers Impacted Depending on the area of the cable failure, it could affect anywhere from a few hundred residential customers to a few thousand it all depends on the number of distribution transformers connected to the failed cable.
	Quantitative Customer Impact and Risk A cable failure could affect anywhere from a few hundred residential customers to a few thousand it all depends on the number of distribution transformers connected to the failed cable. An unplanned outage will result in prolonged outages for customers until a repair is made. The areas identified for replacement have all reached the end of their useful life.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by reducing the risk of cable failures.
	Value of Customer Impact A primary cable failure will result in an unplanned outage which has a high customer impact. The cost of a failure could range from medium to high, depending if the area being serviced is a mix of residential or commercial customers and when the outage occurs (during regular hours or after hours on overtime). Outages are very disruptive to all customer classes. Generally, residential customers find outages to be a nuisance and these are a lower impact but now we are seeing that some residential customers are working from home or they are running their business from home, making an outage impact greater. Generally, GS<50 customers will experience medium impacts on their ability to carry out business. Where GS>50 customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Weather can lead to delays to schedule the work, weather issues can create unsafe work conditions for workers. Typically, only emergency work and construction work related to new connection requests would take priority over primary cable replacements.
Impact on System O&M Costs	Annual operating and maintenance cost will be reduced due to fewer outages as related to cable failures. If a cable does fail in the future, it would now take less time to replace the cable as all new primary cables are now installed in duct.

Impact on Reliability and Safety Factors	Operating a system to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures and increase outage times for customers. Proactive replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage.
Analysis of Project Benefits, Costs, Alternatives, and Timing	There two approaches that one can take, either a reactive replacement approach or the preferred proactive replacement method. The reactive approach leads to worsening reliability. Cable failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. The reactive approach leads to an inefficient operation, strain on resources and inflated inventory levels to mitigate the risk of running out of stock. All contributing to higher O&M costs. With a proactive approach, it will mitigate the risk of unexpected failures, improves safety, maintains reliability and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notifications. It assists with operational resources, as work and inventory can be planned based on the project size. While labour costs associated for cable replacement projects can be controlled/predicted during regular hours versus an unexpected outage that takes place after regular business hours.
“Like for Like” Renewal	Primary cables make up a critical part of the distribution system and most of the cable replacements are completed on a “like for like” basis with new tree retardant XLPE primary cables installed. Since existing cables are direct buried, new duct routes must be established during the design stage for the installation of the new duct. Since only routing has changed, the primary cables installed in duct will be new XLPE standard underground primary cables. The new material installed will provide enhanced performance and reliability and do not directly address future planning objectives.

CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL

Project Number(s): UT47

Project Name: Emergency Transformer Replacement

2023 Budget: $262,500

A. General Information on the project/program

Project Summary

Unexpected and unforeseen transformer failures, which are capital expenditures, arise during the course of the year that require an immediate response. In response, Bluewater Power has established an Emergency Transformer Replacement Fund to allow urgent issues to be addressed in a timely manner. The fund has been used to complete replacement of emergency transformer issues (for any pole mount or pad- mount issue). Any issue would be unforeseen, but require immediate attention within the budget year.

Bluewater budgets to proactively replace transformers before they fail in Project Number UT12 – Transformers. However, if transformers fail prior to their replacement, they are replaced under this UT47.

Having the Emergency Transformer Replacement fund has allowed the Bluewater Power senior management team to provide more conservative and accurate capital budget figures during the annual budget processes knowing that unforeseen transformer issues can be addressed and can be captured using this budget centre.

Pacing for the Bridge and Test years aligns with the 5-year historical average, as shown in the chart below.

	2017	2018	2019	2020	2021	2022 Bridge	2023 Test
Emergency Transformer Replacement	297,897	217,559	230,866	253,558	243,557	250,000	262,500

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: May 2023

In-Service Date: December 2023

Risks to Completion

Risk to completion is minimal. Crews are dispatched as required for any outages as a result of equipment failure.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval

This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).

B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment driver is reliability.
	b) Good Utility Practice Improves reliability providing efficiency and value to customers with immediate repairs. From surveys, customers felt that Bluewater Power should invest in what it predicts is required to replace aging infrastructure and maintain system reliability, even if it may result in a bill increase.
	c) Investment Priority The priority of this project is high, as reliability needs to be maintained by replacing transformers from unexpected failures and restoring power in a safe and efficient manner for customers.
	d) Analysis of Project and Alternatives Limited consideration, as cables have reached the end of useful life and can no longer be safely or properly maintained.
2. Safety	Safety will increase, as any failed infrastructure will be replaced with new infrastructure.
3. Cyber Security, Privacy	Not Applicable.
4. Co-ordination, Interoperability	Co-ordination of outages will be required with affected customers.
5. Environmental Benefits	Immediate replacement protects the environment, as any possible oil leaking from transformers can potentially enter the ground and contaminate the soil thereby having an impact on the environment.
6. Conservation and Demand Management	Not Applicable.
Impact on System O&M Costs	Annual operating and maintenance cost may be reduced due to fewer outages as related to newer installed infrastructure.

	CAPITAL PROJECT SUMMARY SHEET **SYSTEM RENEWAL**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT71 PCB Tx Replacement $157,500

A. General Information on the project/program

Project Summary

Bluewater Power has budgeted to cover the costs required to test and replace transformers our system that have oil containing PCBs.

This project is in response to the PCB Regulations (SOR/2008-273) under the Canadian Environmental Protection Act, 1999, which stipulates that transformers containing greater than 50 mg/kg of PCB must be removed from service by December 31, 2025.

Spending for the Bridge and Test Years is shown in the chart, below.

	2022 Bridge	2023 Test
PCB Tx Replacement	150,000	157,500

Capital Contributions to a Transmitter

Not applicable.

Customer Attachments and Load

Not applicable.

Project Dates and Expenditure Timing

Start Date: January 2023

In-Service Date: December 2025

Risks to Completion

Ability to procure transformers is the biggest risk to completion. Manufacturing lead-times of those resources are becoming increasingly long due to COVID 19 negatively affecting workforce and material issues.
The mitigation plan is to ensure close co-ordination between engineering and operations staff with these projects so that testing and inspections can be done early in the project timeline so that resources can be secured in enough time to ensure completion by the required in-service date.

Bluewater Power is obligated to complete this project in accordance with PCB Regulations (SOR/2008-273) under the Canadian Environmental Protection Act, 1999. This expense is non-discretionary.

Total Capital and O&M Costs Associated with REG Investments

Not applicable. Bluewater does not have REG investments in for forecast DSP period.

Leave to Construct Approval

This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability

a) Investment Driver

This projects is mandatory in nature.

	b) Good Utility Practice Bluewater Power uses Utility Standards Forum standards for transformer replacement. The construction standards are based on the latest CSA code and ensures the installation meets the safety and performance reliability standards.
	c) Investment Priority The priority of this program is high since it is a mandatory program.
	d) Analysis of Project and Alternatives No alternatives considered.
2. Safety	The purpose of the PCB regulations is to “protect the health of Canadian and the environment by preventing the release of polychlorinated biphenyls (PCBs) to the environment.”
3. Cyber Security, Privacy	Not applicable.
4. Co-ordination, Interoperability	Co-ordination will be required with customers affected by outages when transformers are replaced
5. Environmental Benefits	Removes PCBs from our system and disposes of them properly.
6. Conservation and Demand Management	Not applicable.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power typically runs transformers until failure or loading or regulation requires changes.
	Asset Condition Relative to Typical Lifecycle Transformers that may contain PCBs are pre 1980 and are approaching the end of their life cycle.
	Number of Customers Impacted 20 to 30 residential customers at a time may be affected if transformers need to be changed out. Notice will be given with the date and estimated outage time.
	Value of Customer Impact Value of customer impact is low since the distribution system will not change from their perspective
Other Factors Affecting Project Timing	This project must be completed by December of 2025 as per the regulation. Cost and lead-time of transformers are increasing due to COVID-19.
Impact on System O&M Costs	Not applicable.
Analysis of Project Benefits, Costs, Alternatives, and Timing	This is a multi-year project which will end in 2025. The benefits and values cannot not be easily quantified. Distribution system performance will remain the same but PCBs will be removed as per the regulation.
“Like for Like” Renewal	Project is configured to meet PCB Regulations (SOR/2008-273)

BLUEWATER POWER DISTRIBUTION CORPORATION	**CAPITAL PROJECT SUMMARY SHEET** **SYSTEM RENEWAL**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT72 St. Clair Parkway Sarnia (North of LaSalle Line) $262,500

A. General Information on the project/program

Project Summary

This project is to convert 4.8kV facilities to the 16kV/27.6kV system along St. Clair Parkway in Sarnia. This project will convert existing 4.8 kV assets which are currently connected to a `Rabbit` transformer bank (16Kv to 4.8kV transformer) (where assets are typically past their useful life but still operational) are re-built and re-connected to the 16kV/27.6kV system.

Bluewater Power has determined to proactively replace the 4.8kV facilities as part of a long term program where benefits of the program include:

- Increased capacity of the 27.6kV feeders to accommodate residential load creep as well as load
- Increases from future emerging businesses (where applicable).
- overall system Kilowatt (KW) peak reductions;
- improved transformer efficiencies at the higher distribution voltage level;
- lower system line losses as a result of operating at a higher distribution voltage;
- lower risk of failures due to the replacement of 4.8kV assets past useful life;
- Reduced maintenance costs by removing 4.8kV equipment; and
- Increased operating flexibility
- More streamlined spare parts inventory

This project reflects an increase in focus as the assets have reached their end of useful life. Based on the information obtained for failures in the area, at this time it has been determined that the allocated amount would be sufficient to replace the existing infrastructure on a gradual basis. Until it is deemed that failures are critical, then additional funds may be requested.

Capital Contributions to a Transmitter	No capital contributions or cost recovery will be made to the transmitter.	
Customer Attachments and Load	No new customer connections. Existing customers to be transferred to the 27.6Kv feeder upon completion.	
Project Dates and Expenditure Timing	**Start Date:** January 2023	**In-Service Date:** December 2023

Risks to Completion	Availability of resources to co-ordinate with overhead, underground and demand driven projects. The mitigation plan is close co-ordination with these projects and securing resources (both internal and external) to ensure completion.
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).
B. Evaluation Criteria and Information Requirements	
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** Reliability is the main investment driver.
	b) Good Utility Practice Customers will benefit from improved reliability options with the conversion of 4.8Kv facilities to the new 16kV/27.6Kv feeder. Limited engagement with customers is required as most poles are replaced in proximity to existing poles. However, from surveys, customers felt either it was best to replace aging equipment before it breaks down or trusted Bluewater Power's expertise to time the replacement of assets accordingly. In addition, customers also wanted investments to take place in programs to reduce line losses.
	c) Investment Priority The priority of this project is high because conversion is focused in areas where assets have reached their end of useful life.
	d) Analysis of Project and Alternatives Limited consideration. Most of the 4.8 Kv overhead infrastructure installed is at least 60 to 70 years old and has reached its end of useful life.
2. Safety	In converting the 4.8 Kv overhead infrastructure, any equipment that has reached its end of useful life (i.e. such as poles, or cross-arms etc.) will be eliminated from the system increasing overall safety.
3. Cyber Security, Privacy	Not Applicable.
4. Co-ordination, Interoperability	Limited co-ordination is required. Any third party assets located on the poles will require some coordination with the third party to transfer/relocate their infrastructure to the new pole.
5. Environmental Benefits	Limited impact.
6. Conservation and Demand Management	Not Applicable.

C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Bluewater Power follows best utility practices and CSA standards for asset lifecycle optimization. Distribution assets are inspected on a 3 year cycle for urban areas and a 6 year cycle for rural areas.
	Asset Condition Relative to Typical Lifecycle Typical useful life of pole mount is 40 years, wood poles is 45 years. Assets installed on the 4.8kV system are in the range of 60 to 70 years old and were installed dating back sometime in 1950's timeframe.
	Number of Customers Impacted The number of customers affected depends on the number of transformers converted in a defined area. Typically in the range of 20 to 30 customers will be affected per transformer converted.
	Quantitative Customer Impact and Risk Customer impact depends on the location of the transformer and the customers connected. In a residential area, the number of customers impacted might be as many as 30 at a time. For a commercial area, there may only be one customer impacted at a time but that customer will be without power while that transformer is out of service and converted. The duration of the outage varies and can take up to 4 hours to replace a transformer.
	Qualitative Customer Impact and Risk Customer satisfaction is affected by reliability. The project is required in order to maintain system reliability by minimizing the risk of pole, transformer failure and public safety. If a failure were to occur the outage would be unplanned and will likely have a greater negative impact to the customers and their facility.
	Value of Customer Impact Equipment failure has a high customer impact due to power outages. The failure could also pose a public risk due to a possible oil leak. The cost of a failure ranges from medium to high, depending on the area being serviced (residential or commercial) and when the outage occurs (regular hours or after hours on overtime). Outages are very disruptive to all customer classes. Generally, residential customers find outages a nuisance and these are a lower impact but now we are seeing that some residential customers are now working from home or they carry on their business from home, making an outage impact greater. Generally, GS<50 customers will experience medium impacts on their ability to carry out business. Where GS>50 customers will experience medium to higher impacts to their business as a result of an outage.
Other Factors Affecting Project Timing	Other planned work having a higher priority such as completion of new customer connections. This may have an impact on scheduling a conversion project, a typical conversion project may take up to 8 weeks to complete. Weather can lead to delays as well to schedule the planned project work (at the start and during the project), weather issues can create unsafe work conditions for workers.

Impact on System O&M Costs	Annual operating and maintenance cost may be reduced due to fewer outages as related to newer installed infrastructure.
Impact on Reliability and Safety Factors	Operating a system to failure will increase the unpredictability of the work, increase overtime premiums for any after hour failures, as well possible damage to public/private property. Proactive replacements allows Bluewater Power to schedule the work during normal business hours and allows coordination to take place with customers at a time convenient for an outage.
Analysis of Project Benefits, Costs, Alternatives, and Timing	There are two approaches that one can take, either a reactive replacement approach or the preferred a proactive replacement method. The reactive approach leads to worsening reliability, increased public safety risks and environmental concerns. Wood pole failures and transformer failures can cause prolonged outages to Bluewater Power customers. Any repairs required outside of normal business hours will be costly, as they will need to be completed on overtime at a higher hourly rate. Additionally, transformer failures could result in oil leaks and possible environmental damages. The reactive approach leads to an inefficient operation, strain on resources and inflated inventory levels to mitigate the risk of running out of stock. All contributing to higher O&M costs. With a proactive approach, it will mitigate the risk of unexpected failures, improves safety, maintains reliability and lessens outages to Bluewater Power customers. Proactive replacements can be planned during regular business hours with customers receiving advance outage notification. It assists with operational resources, as work can be planned and inventory can be planned based on the scheduled project size. While labour costs associated for the conversion project can be controlled/predicted during regular hours versus an unexpected outage that takes place after regular business hours.
“Like for Like” Renewal	This project is not considered a ‘like for like’ project, a complete pole line design and rebuild will be required to meet the required clearance requirements at the 27.6kV level.

BLUEWATER POWER DISTRIBUTION CORPORATION	**CAPITAL PROJECT SUMMARY SHEET** **SYSTEM RENEWAL**	**Project Number(s):** **Project Name:** **2023 Budget:**	UT73 Albany Substation Breaker Upgrade $210,000

A. General Information on the project/program		
Project Summary	Bluewater Power owns a municipal substation in Petrolia with three bulk oil type circuit breakers which are in poor condition. Bluewater Power is planning to replace those breakers with Viper type breakers.	
Capital Contributions to a Transmitter	Not applicable.	
Customer Attachments and Load	Not applicable.	
Project Dates and Expenditure Timing	**Start Date:** April 2023	**In-Service Date:** December 2023
Risks to Completion	Resource availability and weather conditions are the biggest risks to completion. The station will need to be taken out of service for this work and the load carried on other stations. The project will need to undertaken in the spring when neither heating nor cooling loads are present.	
Total Capital and O&M Costs Associated with REG Investments	Not applicable. Bluewater does not have REG investments in for forecast DSP period.	
Leave to Construct Approval	This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).	
B. Evaluation Criteria and Information Requirements		
1. Efficiency, Customer Value, Reliability	**a) Investment Driver** The main investment drivers are reliability, efficiency, and customer value.	
	b) Good Utility Practice Breaker replacement will greatly improve reliability now and in the future by allowing remote switching both manually and through Bluewater Power's automatic switching program. From surveys, customers felt that Bluewater Power should invest in more remote switches and reclosers.	
	c) Investment Priority The priority of this project is high as breakers have reached their end of useful life as a result of age.	
2. Safety	The station will need to be de-energized during this project.	
3. Cyber Security, Privacy	Not Applicable.	
4. Co-ordination, Interoperability	Limited coordination is required.	

5. Environmental Benefits	Limited impact – removing non-PCB oil from Bluewater Power's system
6. Conservation and Demand Management	Not Applicable.
Impact on System O&M Costs	Annual operating and maintenance cost will be reduced due to fewer truck rolls to block reclosers and for switching
Impact on Reliability and Safety Factors	Reliability will increase due to being able to use these breakers in Bluewater Power's automatic switching program

<table>
<tr><td>BLUEWATER POWER
DISTRIBUTION CORPORATION</td><td>CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL</td><td>Project Number(s):
Project Name:
2023 Budget:</td><td>UT74
4 kV System Upgrade - Sarnia
$817,500</td></tr>
<tr><td colspan="4">A. General Information on the project/program</td></tr>
<tr><td>Project Summary</td><td colspan="3">Bluewater Power owns eleven 4 kV municipal substations in Sarnia with air magnetic type circuit breakers. These breakers are deteriorating with age, Bluewater has no spare breakers or parts for them. Bluewater is planning to upgrade the 4 kV system by converting some of the system to 27.6 kV and working with the 4 kV system to balance load and re-distribute load amongst all the 4 kV feeders with the goal of having a spare cell and breaker in each station, where possible.</td></tr>
<tr><td>Capital Contributions to a Transmitter</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td>Start Date: April 2023</td><td colspan="2">In-Service Date: December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">Resource availability and personnel scheduling</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="4">B. Evaluation Criteria and Information Requirements</td></tr>
<tr><td rowspan="3">1. Efficiency, Customer Value, Reliability</td><td colspan="3">a) Investment Driver
The main investment drivers are reliability, efficiency, and customer value.</td></tr>
<tr><td colspan="3">b) Good Utility Practice
Having a spare cell and breaker in each station will allow for replacement parts if needed, quicker restoration of a feeder outage and available capacity at each station.</td></tr>
<tr><td colspan="3">c) Investment Priority
The priority of this project is medium.</td></tr>
<tr><td>Impact on System O&M Costs</td><td colspan="3">None.</td></tr>
<tr><td>Impact on Reliability and Safety Factors</td><td colspan="3">Reliability will increase due to being able to quicker restoration due to feeder outages and more available capacity</td></tr>
</table>

<table>
<tr><td>BLUEWATER POWER
DISTRIBUTION CORPORATION</td><td>CAPITAL PROJECT SUMMARY SHEET
SYSTEM RENEWAL</td><td>Project Number(s):
Project Name:
2023 Budget:</td><td>UT76
Downtown Switch Replacement
$131,300</td></tr>
<tr><td colspan="4">A. General Information on the project/program</td></tr>
<tr><td>Project Summary</td><td colspan="3">Bluewater has four SF-6 gas switches in place in our downtown network system.

Monthly vault inspections identified that the switch in Vault P requires replacement in 2023 due being at end of life.

Spending in the Bridge and Test years is shown in the chart, below.

<table><tr><td></td><td>2022 Bridge</td><td>2023 Test</td></tr><tr><td>Downtown Switch Replacement</td><td>75,000</td><td>131,300</td></tr></table></td></tr>
<tr><td>Capital Contributions to a Transmitter</td><td colspan="3">No capital contributions or cost recovery will be made to the transmitter.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">This project will affect customers in a specific residential building. It will be a planned outage to replace the switch.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td>Start Date: January 2023</td><td colspan="2">In-Service Date: December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">No risks to completion.</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="4">B. Evaluation Criteria and Information Requirements</td></tr>
<tr><td rowspan="4">1. Efficiency, Customer Value, Reliability</td><td colspan="3">a) Investment Driver
Drivers include safety and reliability.</td></tr>
<tr><td colspan="3">b) Good Utility Practice

Switches allow for the isolation of outage areas, which benefits customers by allowing for less outages.</td></tr>
<tr><td colspan="3">c) Investment Priority

This investment is a medium priority; the condition of the asset is deteriorating and does require replacement.</td></tr>
<tr><td colspan="3">d) Analysis of Project and Alternatives

No other alternatives available.</td></tr>
<tr><td>2. Safety</td><td colspan="3">Needs to be replaced to avoid failures.</td></tr>
<tr><td>3. Cyber Security, Privacy</td><td colspan="3">Not Applicable.</td></tr>
</table>

4. Co-ordination, Interoperability	Coordinating with customer for scheduled outage to accommodate
5. Environmental Benefits	Replacement reduces the risk of Sf-6 leaks.
6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: SYSTEM RENEWAL	
Characteristics of Assets Targeted by a Project and Consequences of Asset Performance Deterioration/Failure	**Asset Performance Target and Asset Lifecycle Optimization** Exceed normal lifecycle throughout maintenance of the switch
	Asset Condition Relative to Typical Lifecycle In a damp and wet environment so makes it hard to achieve lifecycle, but regular inspections
	Number of Customers Impacted Customers in the Kenwick building in Sarnia will be affected.
	Value of Customer Impact Work will be done overnight so limited customer impact no power during outage – likely will last 6-8 hours
Other Factors Affecting Project Timing	City of Sarnia roadworks on the same street will affect timing of this project.
Impact on System O&M Costs	The project should reduce maintenance costs by installing new aluminum-based, non-corrosive materials. The environment surrounding the switch will therefore impact it less, thereby less maintenance will be required.
Impact on Reliability and Safety Factors	Replacing the switch decreases risks of SF6 gas releases to the environment. Additionally, a new switch increases reliability.
Analysis of Project Benefits, Costs, Alternatives, and Timing	Vault inspections no other alternatives available – no other options to consider, timing based on seasonal conditions
“Like for Like” Renewal	Replacing switch with a new version.

<table>
<tr><td>BLUEWATER POWER DISTRIBUTION CORPORATION</td><td>CAPITAL PROJECT SUMMARY SHEET
SYSTEM SERVICE</td><td>Project Number(s):
Project Name:
2023 Budget:</td><td>
Telecommunications – Operations
$375,000</td></tr>
<tr><td colspan="4">A. General Information on the project/program</td></tr>
<tr><td>Project Summary</td><td colspan="3">Radios used for communication between SCADA and 4KV stations and remote switches are obsolete and no longer supported. This budget will allow for the replacement of the existing radios with a mixture of new radios and dark fibre to 8 of Bluewater’s stations.</td></tr>
<tr><td>Capital Contributions to a Transmitter</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Customer Attachments and Load</td><td colspan="3">Not applicable.</td></tr>
<tr><td>Project Dates and Expenditure Timing</td><td colspan="2">Start Date: January 2023</td><td>In-Service Date: December 2023</td></tr>
<tr><td>Risks to Completion</td><td colspan="3">Risks to completion are staff and material availability.</td></tr>
<tr><td>Total Capital and O&M Costs Associated with REG Investments</td><td colspan="3">Not applicable. Bluewater does not have REG investments in for forecast DSP period.</td></tr>
<tr><td>Leave to Construct Approval</td><td colspan="3">This project does not require Leave to Construct, as defined under Section 92 of the Ontario Energy Board Act, 1998 (Act).</td></tr>
<tr><td colspan="4">B. Evaluation Criteria and Information Requirements</td></tr>
<tr><td rowspan="4">1. Efficiency, Customer Value, Reliability</td><td colspan="3">a) Investment Driver

This project is needed to maintain communication between our stations and switches.</td></tr>
<tr><td colspan="3">b) Good Utility Practice

This project provides the continued ability to operate our system from our Control Room</td></tr>
<tr><td colspan="3">c) Investment Priority

This project is a high priority. The existing radios we use form communication with our 4KV stations and remote switches are obsolete and no longer supported. We have a limited stock of spare radios so we need to move to a newer, supported radio.</td></tr>
<tr><td colspan="3">d) Analysis of Project and Alternatives

Market alternatives will be considered such as dark fibre and cellular communication</td></tr>
<tr><td>2. Safety</td><td colspan="3">Not applicable.</td></tr>
<tr><td>3. Cyber Security, Privacy</td><td colspan="3">Both cyber security and privacy are identified in the design and development of these solutions.</td></tr>
<tr><td>4. Co-ordination, Interoperability</td><td colspan="3">Not Applicable.</td></tr>
<tr><td>5. Environmental Benefits</td><td colspan="3">Not Applicable.</td></tr>
</table>

6. Conservation and Demand Management	Not Applicable.
C. Category-Specific Requirements: SYSTEM SERVICE	
Customer Benefits and Costs	Without communication to our stations and remote switches, we would not be able to reliably operate our system. Switching, hold-offs and data acquisition would need to be done manually in the field resulting in less system reliability and reduced safety for out workers.
Regional Electricity Infrastructure Requirements	This project represents a replacement of unsupported radios already in use. No new electrical infrastructure is required
Reliability, Efficiency, Safety, and Coordination Benefits	This project will enable us to maintain our current reliability and safety. If we do nothing we would eventually be left with no communication to our 4KV stations and remote switches
Analysis of Project Benefits and Costs	Doing nothing would result in no communication to our 4KV stations and remote switches greatly hindering our ability to efficiently and safely operating our system