Responses to Building Owners and Managers Association of Greater Toronto Interrogatories

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BOMA-1

Reference:

Exhibit 2, Tab 6, Appendix 2-4, Horizon Distribution System Plan, Appendix D, Distribution System Plan Workbook; Customer Consultation Report, April2014, page 17

(a) To what does Horizon attribute the small, non-representative sample (111 residential customers/8 business customers out of 247,000 customers) that filled out the online workbook? What would a statistically significant sample of (a) residential customers; and (b) business customers; be for this type of study.

(b) Confirm that no response from business customers (the 11) were included in the report.

(c) What steps will Horizon take to ensure that next year's study has a more representative sample?

(d) Ibid, page 20: 81% of residential customers reported an outage in the last twelve months. How many of the outages were due to the two severe storms in 2013? Were comparable studies done in earlier years? What were the results?

(e) Ibid, page 26: The results from residential and business customers differed as to whether the duration of, or number of interruptions during a year was more important. Why is this, in your view?

(f) Ibid, pages 27, 29:

(i) What is meant by the term "running-to-failure", as used in the workbook? Does Horizon interpret running-to-failure to mean replacing the system component when it fails? Please explain. Is it the same as adopting I! reactive approach to managing the asset? Please explain fully.

(ii) It appears that a large percentage of both the residential and commercial respondents preferred running-to-failure "so long as resulting power service interruption is quickly restored" (page 29), as opposed to replacing equipment that is still working. What impact does this finding have on Horizon's approach to asset management. Please discuss.

Which of the twenty-two asset categories listed in the application does Horizon "run-to-failure"?

(iii) What evidence can Horizon offer on the relative costs of repairing/replacing the twenty-two asset categories when they fail, versus replacement (refurbishment, repair) prior to failure? Please discuss fully, and include among the costs incurred by replacing assets before failure, the opportunity cost of capital.

(g) Ibid, page 37: Many food services establishments mentioned two hours as a maximum outage before food spoils. What efforts does Horizon take to ensure if there are outages, they can be restored within two hours?

(h) Has Horizon considered establishing a reserve account for asset renewals as suggested by some of the business respondents? Please discuss.

(i) Ibid, pages 39, 42: What information does Horizon provide its customers with respect to its energy efficiency, demand management, conservation, sustainability, renewable energy and distributed generation policies? Please discuss fully.

G) Ibid, page 40: Does Horizon advise customers, on a regular basis (state frequency), of how the funds it collects through rate increases are spent? If not, why not? Please discuss. Does it intend to discuss this issue more fully in the future?

(k) Ibid, page 42: In repairing outages, what priorities does Horizon employ? Are businesses restored first? Please explain.

(1) Ibid, page 43: How and how much does Horizon communicate with its customers during outages, with respect to likely duration, etc.? Please provide quantitative date if available.

(m) Ibid, page 44: Does Horizon plan to have annual consultations with its customers along the lines of the current exercise? How does the consultation relate to the annual customer satisfaction surveys (Ex4, T3, App 4-1).

(n) Ibid, page 45: Does Horizon have the ability to advise its business customers by email of information on outages, etc.? What about mobile apps that would provide updates to customer account contacts and service restoration times?

(o) Ibid, page 45: What lesson did Horizon take from its experience during the 2013 ice storm and 2013 summer storm? What plans has it formulated for another severe storm?

(p) Ibid, page 62: What would the answer likely have been had you asked, are you "satisfied" with the job Horizon is doing?

(q) Ibid, page 66: Why in your view was the percentage about 50% in favour of spending to maintain the same level of outages, as opposed to further spending to reduce the frequency of outages?

(r) Ibid, page 67: 35% had non-weather related outages. What were the main causes of these outages? What data can Horizon provide on the incidence of failure of different pieces of equipment that result in outages over the last few years.

(s) Ibid, page 68: Why were outages for residents in multi-residential buildings under five stories much higher than the number of outages experienced by residents in buildings over five stories? What are most likely reasons and has Horizon been addressing them?

(t) Ibid, pages 68, 69: Spend to maintain (46%) but to reduce (26%) outages in your area. Why does it vary by area, eg. Downtown Hamilton residents are more supportive of spending to reduce outages? Same question for duration.

(u) Ibid, page 71: What is Horizon spending on new technology by type of technology 64% to 74%? What types of new technology has it invested in the last 5 years? In the next few years? Please provide dollar amounts.

(v) Ibid, page 74: Why does the question posed omit buildings in the first option? Does this not bias the response?

(w) Please provide a copy of the retainer and terms of reference provided to the consultant.

Response:

a) Horizon Utilities does not make any statistically conclusive conclusions on customer needs or preferences based on the feedback collected through the online workbook engagement tool. It could be the case that the low number of responses is indicative that customers largely do not have concerns with the utility. More specifically, however, Horizon Utilities interprets the customer feedback collected through this component of the customer engagement program as directional feedback on customer needs and preferences. The online workbook was never intended to collect statistically significant data on customer preferences or needs, but rather to help inform the design of subsequent phases of the customer engagement program.

As described in the Customer Consultation Report in Exhibit 2, Tab 6, Appendix 2-4, Horizon Distribution System Plan, Appendix D, Distribution System Plan Workbook, the online workbook was designed as a vehicle to provide customers an opportunity to both learn about Horizon Utilities' DSP and share their feedback on the Distribution System Plan, should they choose to participate in this phase of the consultation process.

Traditionally, this type of customer engagement would have occurred through "open-houses" sessions and "town hall-style" public meetings. However, in recent experiences, Horizon Utilities experience in its service territory is that “open-houses” and “town hall” meetings have resulted in very low customer turnout. The online workbook allowed interested customers to provide feedback on their own time, when it was convenient for them.

A statistically significant sample size is dependent on the desired margin of error or confidence level one wants to achieve. With random sampling survey methodologies, a larger sample size results in a smaller margin of error. Depending on the nature of a survey, 200 responses could be considered statistically significant (margin of error: +/-6.9%, 19 times out of 20). However, for more rigorous results, larger sample sizes are always better. This is why Horizon Utilities surveyed 1,011 (margin of error: +/-3.1%, 19 times out of 20) of its residential customers in the statistically significant component of the customer engagement program.

The online workbook was a volunteered, unrepresentative sample of customers. Therefore, a margin of error cannot be applied. A margin of error can only be calculated on random samples (such as a random telephone survey where the universe of customer telephone numbers is known). Therefore, Horizon Utilities cannot speak to a statistically significant sample size of either residential or business customers in the context of the online workbook (which by design does not allow for the calculation of a margin of error).

b) The topline reported results in the online workbook pertain only to residential customers. In the body of the Customer Consultation Report, responses from business customers (the 11) are footnoted. All reported results from the online workbook, whether topline or footnoted, are separated between residential and business customers.

c) Horizon Utilities uses a variety of tools, techniques and approaches to solicit customer feedback, as part of Horizon Utilities’ ongoing customer engagement. Some of these approaches, such as online volunteered surveys or focus groups, provide direction on how follow-up customer engagement approaches should be designed. Other tools, such as random telephone surveys, including the survey the annual Customer Satisfaction Survey as provided in Appendix 4-1, allow Horizon Utilities to collect statistically significant customer feedback.

While the online workbook was not designed to collect feedback from a representative sample of Horizon Utilities' customers, representative customer samples are a regular research practice within the utilities' ongoing customer engagement program.

Horizon Utilities will continue to use a variety of customer engagement approaches to gather customer feedback as it always has. The selected approaches will depend on the nature of the customer feedback that Horizon Utilities needs to collect, analyze and/or consider in order to best serve its customers.

d) The two severe storms in 2013 resulted in 146 unique outages. This represented 10% of the total number of outages incurred in 2013. Horizon Utilities experienced a severe windstorm in 2011 which resulted in 133 unique outages representing 9% of the total number of outages experienced that year.

e) When asked to choose between reducing the number of power outages and reducing the duration of the outages, residential customers supported reducing the duration over the number. Some business respondents indicated that reducing the number of outages is more important than reducing the duration.

In Horizon Utilities' view, these results indicate that any outage, irrespective of duration, is disruptive to a business customer. Business customers have a lower tolerance for service interruptions as each interruption impacts their ability to conduct business and has negative consequences from an operational, financial and customer service perspective. Short term outages are less disruptive to residential customers and as such they can tolerate a higher number of outages with shorter durations. The impact to a residential customer of a short term outage is typically inconvenience. The longer the duration of an outage for a residential customer the higher the inconvenience and the higher the potential for negative financial consequences (e.g. inability to stay in home; spoiled food; no heat).

f)

i) The term "running-to-failure" as used in the workbook means replacing a system component when it fails. This is consistent with Horizon Utilities' interpretation and is the same as adopting a reactive approach to managing the asset. Horizon Utilities' "run-to-failure" ("RTF") or reactive replacement strategy for distribution assets is provided in Exhibit 2, Tab 6, Appendix 2-4, page 145. The strategy involves renewal of assets reactively where unplanned failures represent a low risk to: public or employee safety; system reliability, and customer service; and do not have significant restoration cost. Replacement parts are readily available, in general a small number of customers is impacted, and restoration is relatively quick and straightforward.

ii) This finding is aligned with Horizon Utilities' approach to asset management. Horizon Utilities' uses a combination of proactive and reactive replacement strategies. Horizon Utilities employs a reactive replacement strategy unless the impact of failure can be significant in terms of public or employee safety; cost; system reliability; or customer service; or there is a regulatory or environmental driver. Horizon Utilities utilizes the "run-to-failure" or reactive replacement strategy for all asset categories. However, this strategy is not always the primary replacement strategy. A summary of Horizon Utilities' primary and secondary replacement strategies was provided in Exhibit 2, Tab 6, Appendix 2-4 Table 22 and provided in the table below for ease of reference. For further details refer to Horizon Utilities' response to Interrogatory 2-SEC-15.

Table 1: Replacement Strategy

Assets		Sub-Category	Primary Replacement Strategy	Secondary Replacement Strategy
Substation Transformers			Proactive	Reactive
Substation Circuit Breakers			Proactive	Reactive
Substation Switchgear			Proactive	Reactive
Pole Mounted Transformers			Reactive	Proactive
Overhead Conductors		Primary	Proactive	Reactive
		Secondary	Reactive	Proactive
		Service	Reactive	Proactive
Overhead Line Switches			Reactive	Proactive
Wood Poles			Proactive	Reactive
Concrete Poles			Reactive	Proactive
Underground Cables	XLPE	Primary	Proactive	Reactive
	PILC		Reactive	
	DB	Secondary	Reactive	Proactive
	ID		Reactive	Proactive
	DB	Service	Reactive	Proactive
	ID		Reactive	Proactive
Pad Mounted Transformers			Reactive	Proactive
Pad Mounted Switchgear			Reactive	
Vault Transformers			Reactive	Proactive
Utility Chambers			Reactive	
Vaults			Reactive	
Submersible LBD Switches			Reactive	Proactive

iii) Please refer to Horizon Utilities' responses to Interrogatories 2-AMPCO-6f and 2-AMPCO-9u for evidence on the capital costs of proactive replacement as compared to reactive replacement.

The relative financial costs of repairing/replacing the 22 asset categories when they fail versus replacement prior to failure is dependent on several factors as follows:

- Type of asset
- Current health of asset
- Expected failure date
- Probability of failure

- Repair and maintenance costs
- Frequency of repairs
- Replacement cost
- Magnitude of repairs and maintenance costs relative to replacement costs
- Inflation
- Higher costs associated with reactive replacement as compared to proactive replacement (unplanned work with potential to be required outside business hours at overtime rates)

Horizon Utilities has provided a comparison of relative costs of repairing/replacing assets when they fail versus replacement prior to failure based on a Cross-Linked Polyethylene ("XLPE") cable renewal in the Stoney Creek operating area. The two simplified scenarios provided to compare proactive versus reactive replacement costs are attached as BOMA-1fiii_Attch_Proactive vs. Reactive as a live excel file and are as follows:

Scenario 1:

a. XLPE cable is proactively replaced at a cost of $150,000 in 2015 compared to:
b. XLPE cable is reactively replaced in 2021 at a cost of $150,000 after five years of repairs at $25,800/year plus inflation

Scenario 2

a. XLPE cable is proactively replaced at a cost of $150,000 in 2015 compared to:
b. XLPE cable is reactively replaced in 2021 at a cost of $150,000 after five years of operation without any repairs plus inflation

In Scenario 1, the NPV of the cost to proactively replace the XLPE cable is $125,972 as compared to reactive replacement of $201,881. It is more prudent to proactively replace the XLPE cable due to the magnitude and frequency of the repairs.

In Scenario 2, the NPV of the cost to proactively replace the XLPE cable is $125,972 as compared to reactive replacement of $103,348. It is more prudent to reactively replace the XLPE cable due to the lack of annual repair costs.

As demonstrated in the above example the decision to proactively or reactively replace an asset can vary significantly dependent on the factors listed above. Additionally, the above example considers financial costs only. Horizon Utilities considers financial cost and impact to system operations, customers and employees when evaluating an asset for potential renewal. Proactive replacement strategies are typically deployed where the impact of failure can be significant in terms of public or employee safety, cost, system reliability, and customer service, or there is a regulatory or environmental driver. Reactive replacement strategies include assets where unplanned failures represent a low risk to: public or employee safety; system reliability; and customer service; and have a low restoration cost. Replacement parts are readily available, generally small numbers of customers are impacted, and restoration is relatively quick and straightforward. Replacement strategies by asset category are discussed in further detail on pages 141-147 of the DSP filed as Appendix 2-4 of Exhibit 2, Tab 6.

g) Horizon Utilities has taken the following efforts to ensure that outages are restored as soon as possible:

- Horizon Utilities maintains a 24/7/365 control center and trouble response operation to enable immediate response to service interruptions or emergency situations;

- Horizon Utilities is improving customer service on a continuous basis through system and process initiatives. For example, the implementation of a new Outage Management System ("OMS") system in 2015 will result in a meaningful reduction in the duration of service outages for customers and facilitate proactive customer communication on outages as identified on page 72 of Exhibit 2, Tab 6, Schedule 1; and

- Horizon Utilities has prepared a comprehensive DSP, filed as Appendix 2-4 of Exhibit 2 that provides for approximately $692,664,000 in planned investments in the renewal of Horizon Utilities' distribution system over the next twenty years. This demonstrates the priority that Horizon Utilities places on sustaining and improving the reliability of its distribution service to its customers.

h) Establishing a reserve account to fund asset renewal programs is not consistent with current ratemaking practices of the Ontario Energy Board ("OEB"). The creation of such an account would have a negative effect on current customer rates for the benefit of smoothing customer rates in the future. Horizon Utilities is not aware of any electricity distributor that has established such an account. In addition, the OEB's Accounting Procedures Handbook makes no specific reference to the ability to consider such an alternative. Accordingly, Horizon Utilities has not considered such in this application.

i) Horizon Utilities provides its customers with information regarding energy efficiency, demand management, conservation, sustainability, renewable energy and distributed generation through a variety of communication methods and channels.

Energy efficiency, demand management and conservation:
Horizon Utilities provides its customers with information regarding energy efficiency, demand management and conservation initiatives as provided in partnership with the Ontario Power Authority ("OPA") or that Horizon Utilities has undertaken on its own initiative.

Horizon Utilities utilizes a number of communication channels to provide its customers with energy efficiency and conservation and demand management ("CDM") information that include: advertising; email; bill inserts; promotional program offers; energy use benchmarking information; door-to-door promotions; outbound calling; media releases; customer recognition events; community events; social media, including Twitter and Facebook; direct contact with energy management or renewable / distributed energy professionals, and discussions with trained CDM and Customer Service staff.

Horizon Utilities' website (www.horizonutilities.com) provides customers with access to the complete range of energy efficiency and CDM related tools and information. The suite of on-line customer tools enable customers to better understand their energy usage and their manage costs. The website also has tips on how customers can increase the energy efficiency of their home and reduce the overall energy consumption of their household or business.

General updates to CDM programs are provided through media and social media releases.

Horizon Utilities has maintained a team of energy management specialists dedicated to CDM program implementation initiatives since 2005. The CDM Team is available to respond to customer specific queries and information requests and follows a comprehensive marketing and customer communications plan. As described in Exhibit 4, Tab 3, Schedule 2, at page 16 onwards, Horizon Utilities' CDM business unit supports Ontario's current CDM framework and assists all customer segments in the management of their energy usage. These professional energy managers work proactively with business and industrial customers to engage them in energy management initiatives and program offerings. All Horizon Utilities staff receive information about conservation and sustainability initiatives to increase their awareness and engage them as conservation ambassadors.

Horizon Utilities has also contracted with a third-party vendor to do door-to-door promotion of OPA CDM programs with small commercial customers. Horizon Utilities pioneered the strategy of making contact with local Business Improvement Associations (or "BIAs") regarding the programs, having the BIAs market the programs to their members, and thereby increasing the communication channels and information provided to customer regarding energy efficiency and CDM initiatives.

Horizon Utilities' Customer Service Representatives are trained to provide information on the importance of energy efficiency and conservation in general as it relates to customer cost management and specifically about the CDM programs and initiatives.

<u>Sustainability</u>

Horizon Utilities provides information on its sustainability policies and programs. Horizon Utilities has featured these achievements in information to customers and stakeholders on: its website; in its annual reports; and through media releases and social media.

Horizon Utilities commenced triple bottom line measurement and reporting of social, environmental and economic considerations in 2008. Horizon Utilities has also begun to use sustainable development principles to improve its programs for customers in a way that contributes to the sustainability of the community.

Renewable energy and distributed generation policies

Regarding renewable energy (i.e., OPA micro-FIT and FIT) and distributed generation connection agreements and programs, Horizon Utilities has dedicated staff that provide information to customer queries about policies and requests for connection of projects. This function is managed through the Customer Connections business unit.

The Horizon Utilities website provides robust information regarding renewable energy and distributed generation connection opportunities including: how to connect generation to Horizon Utilities distribution system for various projects and sizes; what it means to generate electricity and sell it to the distribution grid, the process, requirements, and options for connecting green energy including solar, wind, water or biomass; the role that government agencies and other organizations have in project connections; and the metering and technical requirements to consider regarding renewable energy or distributed energy projects.

Horizon Utilities' Customer Service Representatives are also trained to respond to initial customer inquiries regarding renewable energy and distributed energy projects. They may direct customers to Horizon Utilities' subject matter experts as necessary.

j) [identified in the as-filed interrogatories as G]

Horizon Utilities provides customers with information regarding rate changes and the primary reason(s) for rate increases at the time of the rate change. Customer communications of rate changes occur at the time of Horizon Utilities' distribution rate change which most recently occurs January 1 of each year; in May and October when the Ontario Energy Board revises the Regulated Price Plan rates for residential and small business customers; and at the commencement or termination of rate riders which impact customer rates.

Rate change customer communication includes the rate change, the impact to the rate classes, and the primary reasons for the rate change. Customer information regarding rate increases and why the change or increase is necessary are provided through multiple channels.

Horizon Utilities' website includes the current and previous rates for residential, general service, and Large Use customers. To provide context, the rationale for the rate increase as well as the impact to an average customer in each rate class is provided on a dollar and percentage basis.

Horizon Utilities also provides awareness of rate increases via a notice on the customer's invoice which directs customers to Horizon Utilities' website or the Call Centre. Call Centre staff are trained to provide information to customers regarding rate increases and why additional funding is required.

Beyond the Call Centre, Horizon Utilities' staff are provided with training about Horizon Utilities' distribution rate increases to promote adhoc customer engagement through discussions with customers, friends, neighbours, and the community.

Horizon Utilities' staff offer to meet with key account customers and Large Users regularly, typically on an annual basis. Large Users are provided with a letter that provides a notice of the rate change; the impacts of the rate change; and the primary drivers for the rate change.

Horizon Utilities hosts Contractor and Developer discussions on an as-needed basis, but typically annually, to provide information regarding Horizon Utilities' processes; rates; and current and future investment requirements.

Horizon Utilities has increased customer awareness of investments and rate requirements through its customer consultation of Horizon Utilities' DSP which included facilitated focus groups, meetings with key account customers, an on-line workbook, and a DSP-related survey. Horizon Utilities continuously reviews its methods of customer communication in order to improve customer knowledge and awareness.

k) In responding to outages, Horizon Utilities employs the following priorities for restoration;

1. Wire Down calls (public and employee safety);

2. Emergency Services Requests (i.e. EMS, Police, Fire, Ambulance);
3. Critical customers (e.g. hospitals, pumping stations, industrial customers where loss of power results in a negative environmental impact);
4. Large feeders, large districts;
5. No power calls (complete loss of service);
6. Lights out calls (partial loss of service); and
7. General service calls (limbs on wires, stack damage, etc).

Businesses are not necessarily restored first. Horizon Utilities prioritizes restoration based on impact to public and employee safety and critical customers as identified in the prioritized list above.

l) [identified in the interrogatories from the intervenor as 1)]

Horizon Utilities' goal is to provide accurate and timely restoration information to customers in the event of planned and unplanned outages.

For planned work, the reason and the duration of the required outage is communicated in advance to residential and business customers. The duration is estimated based upon the nature of the work. Pre-work, as appropriate, and other mitigations are utilized to minimize the duration of the outage. Customers are informed of the planned work by hand-delivered notice, telephone call, or in person. Horizon Utilities has approximately 350 planned work outages annually.

Horizon Utilities communicates information to customers regarding unplanned outages through a variety of channels including: the provision of outage maps and information on Horizon Utilities' website and mobile website; messaging through the telephone system; by contacting the Call Centre or the 24-hour after hours emergency number; by email to Large Use and key customers, and through social media channels including Twitter and Facebook.

Outage restoration information, including the cause and estimated time to resolve the outage, is updated as it becomes available. Generally it is provided every two to four hours.

In 2013, 446 outage notifications were posted to Horizon Utilities' website, added to the telephone system messaging, and auto-Tweeted to customers. An additional 408 updates to the original outage notifications were provided to customers via the Horizon Utilities website and Twitter.

Horizon Utilities also provides customer-specific information to key customers including Large Use customers via email and direct telephone contact to designated representatives. In 2013, more than 30 custom emails regarding outages, causation, and restoration information were provided to customers.

During outages of significant volume or duration, Horizon Utilities will also provide outage information to City of Hamilton and City of St. Catharines staff and councillors; and the media as appropriate to assist in the delivery of information to customers.

m) Horizon Utilities has not yet finalized its plans or the frequency of future customer consultation as it relates to the development of upcoming Distribution System Plans. Consultation regarding specific projects and the distribution system plan is not currently integrated with the annual customer satisfaction survey. Please also see Horizon Utilities' response to part c) above.

n) Horizon Utilities has a limited ability to provide email outage information to business, industrial, and other key customers as this is a manual process. Horizon Utilities has approximately 50 customers who receive custom outage information including hospitals, large user customers generators, and other key customers. A small number of key customers receive automated email notifications of Supervisory Control and Data Acquisition ("SCADA") alarms affecting the electricity supply to their location.

As described in Exhibit 2, Tab 6, Schedule 1, starting on page 72, Horizon Utilities will implement the first phase of an Outage Management System ("OMS") in the 2014. Enhancements of the OMS systems and its customer interfaces are planned through to 2019. These enhancements will enable automated email and text outage notifications to all customers based on customer preference.

o) Horizon Utilities conducts a review after each major outage event, including the July windstorm and the December ice storm, to identify potential opportunities for improvement. The principle lessons learned from the 2013 storms are as follows:

Outage awareness and management:

- Recording outage information

  Horizon Utilities' telephone agents utilize a manual tool to record customer outage information. The outage information is subsequently downloaded by the Network Operating staff that filters and prioritizes the customer outages for restoration. The outage entry tool was a "dumb screen" to users which did not enable them to view if an outage had already been reported or if there was other customer-supplied information. This represents unnecessary work for Call Center and Control Room staff and results in less efficient use of field crews because the calls have already been recorded and dispatched. This tool has recently been enhanced to interface with the customer account to ensure customer information is accurately reported. The major limiting factor to this tool is that the file can only be accessed by one person (dispatcher) and during large outages, multiple people are required to access and organize data.

- Social Media

  Horizon Utilities has also implemented improved communications through social media and its website to help inform customers about which outages Horizon Utilities is aware and for which work is currently underway in order to help reduce the number of these repeat calls. The manual tools which Horizon Utilities currently uses are not efficient in the event of major events. Plans are in place to implement an Outage Management System as discussed in Exhibit 4, Tab 2, Schedule 2, page 21 to improve this capability.

- Dispatch process review

  Review and prioritization of the dispatch process revealed that with thousands of calls received in a short time period, Field Supervisor support in the Control Room was helpful in matching calls with field crew capabilities, and coordinating overall response and restoration. This approach is now adopted during severe storms.

- Engagement of Engineering and Technician staff

All of the services attached to poles can come to the ground during severe storms. It is a tremendous challenge to maximize the effectiveness of response and restoration with limited resources. Horizon Utilities engages engineering and technician staff in field operations to respond to calls that are suspected to be related to telephone/cable services and other non-hydro services to confirm if crews need to respond. This is helpful in order to triage calls to maximize the effectiveness of restoration crews. When the triage crews come across downed lines or other public hazards, they stand by on site to ensure the area is made safe until crews can be made available.

- LDC aid arrangements

Horizon Utilities has mutual aid arrangements with neighbouring LDCs. The neighbouring LDCs are effective in providing assistance depending on the nature of the event. Generally they are not as effective for events that are widespread in and around Horizon Utilities' service area. In the event of a major storm, it is possible that neighbouring utilities may also be affected by the same weather event and therefore unable to assist if they have their own outages with which to deal. As such, Horizon Utilities is investigating mutual aid agreements with utilities that are located outside of a 100 km range.

- Engagement with Municipal Emergency Operations Centre

Engagement of the City of Hamilton Emergency Operations Centre was considered earlier in the process for the December ice storm which helped in the coordination of services between Horizon Utilities and departments within the City of Hamilton. City Forestry staff, for example, were effectively engaged which allowed coordination of City of Hamilton efforts with the contracted tree trimming services that Horizon Utilities had engaged.

Customer communications:

The experience of the July and December storm events demonstrates that customers expect accurate and timely communications regarding outages. Currently, the primary communication channel for customers to advise of a power outage during a major event is by calling into the Call Centre. In the event of wide-spread outages, the wait times to talk to an agent may be lengthy. Customers may obtain updates regarding power outages and restoration times through the Call Centre, the Horizon Utilities' website and social media including Twitter.

The implementation of the OMS system is foundational to Horizon Utilities' ability to provide timely automated communications to customers including acknowledgement of the outage and refinement of restoration time estimates as they become available.

As the OMS implementation progresses, enhancements will include the ability to receive inbound notification of outages through new automated channels including the Horizon Utilities website and through automated messaging provided by the Integrated Voice Response ("IVR") telephony. Outbound notifications and update communications will be based upon customer communication preferences; options are anticipated to include IVR telephony, email, and text messages.

Some customers communicated that even after Horizon Utilities had repaired distribution and service lines in their area, they were still without power. Investigation revealed that most customers did not know that repair to portions of their service was their responsibility. They also did not know how to proceed with arranging repair or calling for an Electrical Safety Authority ("ESA") inspection. Horizon Utilities now advises customers through its social media, newspapers, website and door hangers as to how to recognize damage to their service, whether it is their responsibility to repair, and how to proceed. This allows customers to be pro-active and participate in their service restoration.

Horizon Utilities continues to expand its use of social media during and in advance of forecasted major storms. Twitter and Facebook are valuable tools for general communications to customers to provide advance warning of potential major weather events, and how to access Horizon Utilities' on-line outage maps to obtain outage and restoration information in the event of power interruptions.

Emergency Planning:

Horizon Utilities utilizes a continuous improvement model with regard to emergency planning. Horizon Utilities refines the documentation of its Emergency Plan and protocols based upon its most recent experiences. Based on staff feedback, the Emergency Plan has been made available through an internal Sharepoint website and expanded beyond organizational documentation to include departmental emergency plans.

p) Horizon Utilities did not specifically ask, "Are you satisfied with the job Horizon Utilities is doing?" However, based upon the results of the customer consultation as provided in the Customer Consultation Report of Exhibit 2, Appendix 2-4, Appendix D, and the customer satisfaction survey provided in Exhibit 4, Tab 3, Appendix 4-1 in which customers indicated their satisfaction level with Horizon Utilities to be 89% and 95% respectively, Horizon Utilities believes that the majority of its customers would respond that they are "satisfied" with the job that Horizon Utilities is doing.

q) Horizon Utilities has checked the reference in this interrogatory and believes that the appropriate reference from the evidence is page 68. No electrical distribution system can deliver perfectly reliable electricity The more reliable the system, the more expensive the system is to build and maintain. The telephone survey was largely designed to allow residential customers to make value judgements between the level of system reliability they can live with and the costs they are willing to pay. Ultimately, Horizon Utilities was seeking preferences on this basis.

Given the associated costs of delivering a more reliable system (i.e. less than two power service interruptions a year on average), Horizon Utilities interprets this finding on page 68 to mean that almost half (46%) of its residential customers are satisfied with the current level of reliability and want the utility's investment plan to mitigate related reliability risks and avoid further deterioration of service levels.

r) Please refer to Horizon Utilities' response to Interrogatory 2-SIA-13 part a) for the identification of the major causes of outages and their relative impact. Please also refer to Horizon Utilities' response to Interrogatory 2-AMPCO-9 j) for the identification of the equipment, material failure sub causes and their relative impacts.

s) The survey results indicating that outages for multi-residential buildings under five stories are higher than the number of outages experienced by residents in buildings over five stories is a result of the composition and experience of the customers who responded to the survey. Horizon Utilities does not record outage information to the level of detail which would facilitate differentiating service experienced by customers in multi-residential buildings under five stories from customers in buildings over five stories. As such Horizon Utilities cannot validate if actual service performance for these two groups of customers aligns with the survey results.

t) Different regions within Horizon Utilities' service areas clearly have different needs and preferences related to the balance between system reliability and costs. This is likely due to demographic characteristics such as dwelling type and household income levels.

For example, research would suggest that those in suburban neighbourhoods feel less impacted by a power service interruption than downtown residents. In the qualitative component of Horizon Utilities' customer engagement program, a suburban respondent suggested that the odd power outage was an opportunity to spend time with family, talk and play a board game in the absence of television, computers and other electronic distractions. On the contrary, for a downtown resident living in a condo, power service interruptions created a much more significant inconvenience due to limited elevator access and lack of air conditioning on hot summer days.

u) The reference on page 71 of the Customer Consultation Report identifies that 64% of all respondents support investments in new technology that will increase reliability, provide efficiencies, and provide cost savings. Analysis by area indicates that 74% of the respondents within the Hamilton West operating area support investments in new technology. The difference in these two responses does not correspond to a varying investment level between operating areas but rather a difference in support between the respondents based on the operating area in which they reside.

This question gauges customer acceptance to investments required to improve reliability of the electricity system. Horizon Utilities' has invested and plans to invest in the following new technologies in order to improve system reliability:

- Geospatial Information System ("GIS") Renewal (refer to Table 2-62 on page 70, Exhibit 2, Tab 6, Schedule 1)

  The scope of the GIS Renewal includes the integration and deployment of an Outage Management System ("OMS"). The principal benefits derived from the implementation of OMS are as follows:

  - a meaningful reduction in the duration of service outages for customer;
  - proactive customer communication on outages;
  - improved productivity as power outages can be identified without sending out a truck to investigate; and
  - improved productivity as a result of the elimination of the current manual process of entering outage data from Supervisory Control and Data Acquisition ("SCADA") into the Customer Information System ("CIS") and other systems to manage outages under the status quo.

  Horizon Utilities' annual investment in the GIS Renewal project is as follows:

2012 Actuals:	$ 807,000
2013 Actuals:	$1,103,442
2014 Bridge Year:	$1,869,308
2015 Test Year:	$ 205,276

  Distribution Automation (refer to page 126 in Exhibit 2, Tab 6, Schedule 3 and Appendix 2-AA on page 14 in Exhibit 2, Tab 6, Schedule 3)

  Distribution automation involves the installation of automated load break disconnect switches (i.e. the ability to remotely identify faulted areas and remotely restore service through the use of remotely controlled switches). Automated switches will be installed on the poorest performing feeders and feeders with high customer counts and long lengths. Automated switches will be installed along these feeders to provide the ability to sectionalize the feeder and at normal open points to allow for the load to be transferred to a neighbouring feeder.

Horizon Utilities' annual investment in the Distribution Automation project is as follows:

2014 : $1,250,000

2015 : $1,250,000

In addition to the Distribution Automation project identified above, Horizon Utilities' plans to incorporate automated switches in all Capital Investment Programs where applicable.

- Substation Breaker and Relay Renewal (refer to Table 2-79 on page 34 in Exhibit 2, Tab 6, Schedule 3)

The Substation Breaker and Relay Renewal project involved the renewal of end-of-life substation assets with vacuum circuit breakers and electronic protection relays providing improved operating characteristics and system protection capabilities. Horizon Utilities' annual investment in this program was as follows:

2011 Actual:	$ 223,000
2012 Actual:	$1,998,000
2013 Actual:	$3,864,456

v) Respondents were asked to select which of the following options best represents their point of view as it relates to Horizon Utilities' investment in equipment and tools:

Option 1: While Horizon Utilities should be wise with its spending, it is important that staff have the equipment and tools they need to manage the system efficiently and reliably.

Option 2: Horizon Utilities should find ways to make do with the buildings, equipment and IT systems it already has.

The first option did not implicitly omit buildings. The first option refers to "equipment and tools" which Horizon Utilities defined in the preamble to the question as "buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage service performance and customer information" as identified on page 74 of the Innovative Customer Consultation Report filed as Appendix D of Appendix 2-4. Horizon Utilities does not believe that the phrasing of the first option biased the response because "equipment and tools" was defined in the preamble to the question to include buildings.

w) Please see Horizon Utilities' response to 2-SEC-18.

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BOMA-2

Reference:

The 4kV and 8kV Conversion Program (Ex 2, Sch 6, Appendix 2-4, Appendix F, p4).

Preamble:

The 2015-2019 tranche for this program comprises $66 million of the total renewal expenditures of $148 million over the IRM term. Total IRM plan capital is $229 million including customer access, service and building capital.

The principle driver of the revenue deficiency is an increase in distribution system investments to review aging infrastructure and address declining system reliability (Ex 1, T2, Sch 6, p3 of 42).

The original (4kV/8kV) plan was initiated in 2008 using the distribution assets as the primary driver for renewal and conversion. Ibid. Appendix F

BOMA would like to have more information on the rationale for the 4kV/8kV conversion program, its history, and the calculations that demonstrate it is both necessary and desirable.

(a) Id, p3: Please provide a copy of the original plan from 2008 and the 2009 update.

(b) Id, p3: Please provide a copy of the AESI 2010 Substation Asset Condition Assessment (Id, p4).

(c) Id, p3: Please provide a copy of the design model referred to on p3 (Id, p3).

(d) Please provide in a single table, the condition assessment of the 28 substation assets, currently set out in pages 13-40 of Appendix F

(i) Please explain the "weightings" assigned to various (but often different) items in the substation ratings in pages 13-40. Provide examples to illustrate.

(ii) Please explain the difference in relative weightings of specific assets in the assessments. For example, in some of these assessments, the transformer condition is given a thirty percent weighting; in others, twenty-five percent.

(iii) How do the assessments and weightings of outdoor and indoor stations differ, eg. John versus Kenilworth?

(iv) For each station assessment in the Renewal Program compare the assessment with the assessments in the Kinetics Study.

(v) What are the factors that are used to assign ACA for stations' civil structures?

(vi) Please explain what smart grid strategies will be incorporated in each component of the 4 kV/8kV conversion programs during the term of the customized IRM, 2015-2019.

(vii) (a) Please provide a table like those on pages 43 and 44, which show for each station and feeders which originate from it, for which work will be done on the 4/8kV conversion program during the 2014-2019 period, the capital expenditure per year per system component, eg. 4 kV to 13/27/kV conversions, station switchgear, and transformer poles. For the conversion program, provide a year by year description of the planned renewal/conversion per year which shows clearly which assets are being replaced with other assets, and which existing assets are being removed and not replaced and what interim upgrades to assets that will subsequently be removed or replaced are being made .

(b) Please explain how 4/8kV the station and line components were selected for work in the 2014-2019 period. Describe each category of asset, and in each operating region separately.

(viii) Which stations and the areas covered by feeders for those stations, has 4/8kV conversion work was done once the period 2008-2014, inclusive? Please provide the data which demonstrate the impacts on frequency of outages, duration, total repair cost, as compared to the data for these stations and feeders in the years before this work took place.

(e) Preamble:

A major initiative driving the increased renewed investment are Horizon's 4 kV and 8 kV Renewal Program (Exhibit 1, Tab 2, Schedule 6, page 13).

o Exhibit 2, Tab 6, Schedule 1, page 16 of 74, Table 2-46; As noted above, the proposed 4 kV/8 kV related investments are approximately $65 million over the IR term.

o The Kinectrics Report conclusion, as summarized in part, by Horizon (Ibid, page 6 of 74) (See also Figure 2-1, Health Index of All Asset Groups, Ibid, page 6 of 74), included the statement that "Horizon Utilities substations infrastructure investments in recent years has been effective in improving the overall health of the substation asset groups as compared to the previous asset condition assessments. Substation transformers are in good shape with substation circuit breakers and switchgear being in adequate conditions. A small portion of breakers remain in poor condition."

o Against this assessment, please explain why Horizon is contemplating replacing the twenty-eight substations with higher voltage lines over a

forty year term, and $65 million worth of expenditures of over the IR term alone on that project. (See also Figure 2-1, Health Index of All Asset Groups, Ibid, page 6 of74).

o Why is it economic and necessary for Horizon to continue a program that has as one of the primary objectives the removal of the remaining twenty-eight substations?

(f) Exhibit 2, Tab 1, Schedule 1, page 1: The Conversion

"Conversion to a higher voltage line will provide greater security as the higher voltage system is designed with more redundancy, better interoperability and requires no intermediary substation assets."

Please provide a more detailed explanation of each of these advantages, including a definition of which is meant by "more redundancy and better interoperability".

(g) Ref. DSP (Appendix F) p1

Please provide data from Horizon's experience which documents the extent to which the external lines losses for 4/8kV lines are higher than from 13-8kV and 27.6kV lines.

Response:

a) Horizon Utilities provides copies of the plan from the 2008 and 2009 update as the following attachments: "BOMA-2_Attch_1_2008 Renewal Plan" and BOMA-2_Attch_2_2009 Renewal Plan.

b) Horizon Utilities provides a copy of the 2010 Substation Asset Condition Assessment ("SACA") as attachment "BOMA-2_Attch_3_ 2010 SACA".

c) Horizon Utilities does not refer to a design model on page 3 of the 4kV and 8kV Renewal Program. It does refer to a decision model which is part of the 4kV and 8kV Renewal Program and elaborated on in Section 4 – Renewal Plan Methodology on pages 7-9 of Exhibit 2, Appendix F. The renewal program methodology (i.e., decision model) is used to rank the order of conversion for Horizon Utilities' 28 stations. The decision model used to establish priorities for 4kV and 8kV station conversions considers four criteria: station asset health; associated distribution assets health: feeder dependencies; and customer impact of failure. Horizon Utilities describes each step in the decision process below:

Step 1:

a. Horizon Utilities' 28 substations are ranked from 1 to 28, with 1 representing the substation with the lowest overall health and 28 representing the substation with the highest overall health. The health of substation assets is identified in Exhibit 2, Schedule 6, Appendix 2-4, Appendix F, pages 13-40.

b. Horizon Utilities ranks the health of the distribution assets serviced by each substation from 1 to 28, with 1 representing the distribution assets with the lowest overall health and 28 representing the distribution assets with the highest overall health. These rankings are based on engineering assessments performed on a feeder-by-feeder basis.

c. Horizon Utilities determines the overall ranking for the substation and associated distribution assets based on an average of the two rankings described in Step 1a and Step 1b; the lower the total ranking, the higher the priority for conversion.

Step 2:

Substations are grouped by operating area, as discussed in Exhibit 2, Tab 6, Appendix 2-4, Appendix F, page 8, under feeder dependency. The criterion for grouping substations into the same operating area is the ability to connect and provide operating back-up to one another during emergencies or load transfers to facilitate maintenance or related activities. Substations within the same operating area have a high degree of interconnection with one another. Substations within different operating areas have little or no interconnections with one another. The operating areas are provided on page 8 of Appendix F of the DSP filed as Appendix 2-4 in Exhibit 2.

Step 3:

Operating areas are prioritized for conversion by averaging the overall substation scores for each operating area described in Step 1 above. The lower the score for the operating area, the higher the priority for conversion.

Step 4:

The ability to transfer load between feeders in an operating area mitigates the impact on service of asset failures in the operating area. Each feeder is analyzed to determine: the capacity to pick up additional load; topology constraints; and proximity to adjacent station feeders. A feeder dependency score is determined for each operating area. The lower the Feeder Dependency score, the higher the priority for conversion.

Step 5:

Horizon Utilities determines a customer impact score based on the concept of value of service as described in Exhibit 2, Tab 6, Appendix 2-4, Appendix F, page 8. The lower the customer impact score, the higher the customer impact and consequently the higher the priority for conversion.

Step 6:

Horizon Utilities determines an overall score for conversion of substations in an operating area by averaging the operating area score, feeder dependency score, and customer impact scores to arrive at a composite score for each operating area. The lower the composite score, the higher the priority for conversion. Horizon Utilities uses the total composite score to establish priorities for substation conversion.

d) Horizon Utilities has provided the asset condition assessment of the substation assets, set out in pages 13-40 of Appendix F in Table 1 below.

Table 1: Condition Assessment of 28 Horizon Utilities' Substation Assets

Station	Trans-former	Breaker	Recloser	Switch Gear	P&C	Station Service	Site & Civil	Bus, Switches & Structures	Station Health Index
Aberdeen	90%	39%	n/a	46%	35%	45%	44%	n/a	53%
Baldwin	93%	n/a	96%	n/a	67%	40%	83%	83%	84%
Grantham	82%	52%	n/a	57%	35%	63%	59%	n/a	58%
Bartonville	86%	100%	n/a	52%	90%	10%	66%	n/a	77%
Deerhurst	97%	n/a	100%	n/a	n/a	60%	69%	100%	79%
Galbraith	95%	n/a	100%	93%	100%	45%	56%	100%	91%
Vine	70%	52%	n/a	61%	50%	38%	53%	n/a	57%
Caroline	86%	51%	n/a	51%	55%	25%	64%	n/a	61%
Dewitt	82%	n/a	100%	n/a	0%	55%	65%	100%	74%
Welland	85%	60%	n/a	55%	40%	38%	45%	n/a	59%
Central	90%	46%	n/a	58%	30%	20%	62%	n/a	56%
John	80%	n/a	100%	n/a	67%	50%	95%	86%	83%
Cope	88%	100%	n/a	71%	90%	40%	82%	n/a	84%
York	88%	n/a	100%	n/a	90%	40%	73%	83%	85%
Eastmount	90%	45%	n/a	69%	45%	10%	78%	n/a	63%
Elmwood	93%	73%	n/a	55%	35%	15%	82%	n/a	65%
Highland	95%	33%	n/a	36%	25%	50%	72%	n/a	52%
Hughson	95%	79%	n/a	81%	60%	40%	55%	n/a	75%
Kenilworth	91%	100%	n/a	50%	90%	25%	61%	n/a	78%
Mohawk	85%	100%	n/a	59%	90%	25%	68%	n/a	79%
Mountain	91%	100%	n/a	57%	90%	25%	53%	n/a	79%
Ottawa	89%	100%	n/a	76%	90%	25%	86%	n/a	85%
Parkdale	100%	100%	n/a	100%	90%	25%	66%	n/a	91%
Spadina	88%	68%	n/a	79%	90%	20%	68%	n/a	77%
Strouds	85%	70%	n/a	37%	55%	25%	71%	n/a	62%
Wellington	85%	100%	n/a	59%	90%	25%	83%	n/a	81%
Wentworth	90%	82%	n/a	73%	90%	25%	64%	n/a	79%
Whitney	92%	65%	n/a	43%	45%	30%	83%	n/a	63%

d) i) Horizon Utilities uses weightings to assign the level of importance of each component to the continued reliable operation of the substation. The sum of the weightings for assets in a substation is 100%. Outdoor substations do not have breakers and as such that component receives a weighting of 0% for outdoor substations. Similarly, indoor substations do not have bus, switches and structures and as such that component receives a weighting of 0% for indoor substations.

ii) The two components that are weighted differently between indoor and outdoor stations are transformers and protection and control ("P&C") equipment. The difference in relative weightings of these components reflects their impact on the service continuity of the substation.

Transformers: Horizon Utilities' indoor substations are typically constructed with multiple transformers whereas outdoor substations have a single transformer. Failure of a single transformer has a higher impact on the overall operation for an outdoor substation as compared to an indoor station. As such, transformers have a higher weighting for outdoor substations.

P&C Equipment: P&C equipment for indoor substations is more complex and includes additional functionality as compared to outdoor substations. As such, the criticality of P&C equipment and consequently its weighting is higher in indoor substations than outdoor substations.

iii) Horizon Utilities has provided the weightings for the John (outdoor) and Kenilworth (indoor) substations in Table 2 below. See Horizon Utilities' response to parts di and dii above for the difference in the weightings between outdoor and indoor substations.

Table 2: Component Weightings for Outdoor and Indoor Substations

Components	Indoor	Outdoor
Transformer	25%	30%
Breaker	20%	n/a
Reclosers	n/a	15%
Switch Gear	20%	n/a
P&C	20%	15%
Station Service	5%	5%
Site & Civil	10%	10%
Bus, Switches & Structures	n/a	25%
Station Health Index	**100%**	**100%**

Horizon Utilities has interpreted "assessment" to mean the health index of each component. The health index of each component is not a function of whether the substation is indoors or outdoors. Overall asset health is a function of the component weightings identified in Table 2 above and the health of each component.

iv) Horizon Utilities provides a comparison of the historic scores from the 2010 SACA report to the Kinectrics' assessment in Table 3 below. It is important when reviewing the results to note that the SACA report was completed in 2010, and the Kinectrics' assessment was completed in 2013. Horizon Utilities made several investments in substation renewal as part of the 4kV and 8kV Renewal Plan over this time period. The substations for which Horizon Utilities made investments have been highlighted in yellow in Table 3.

Table 3: 2010 SACA compared to Kinectrics' Assessment

Station	Transformer		Breaker		Switchgear	
	SACA	Kinectrics	SACA	Kinectrics	SACA	Kinectrics
Aberdeen	91%	90%	31%	39%	57%	46%
Baldwin	96%	93%	0%	0%	0%	0%
Grantham	71%	82%	50%	52%	64%	57%
Bartonville	91%	86%	64%	100%	53%	52%
Deerhurst	88%	97%	0%	0%	0%	0%
Galbraith	78%	95%	0%	0%	78%	93%
Vine	62%	70%	43%	52%	65%	61%
Caroline	73%	86%	50%	51%	39%	51%
Dewitt	85%	82%	0%	0%	0%	0%
Welland	61%	85%	57%	60%	64%	55%
Central	96%	90%	60%	46%	64%	58%
John	87%	80%	0%	0%	0%	0%
Cope	89%	88%	50%	100%	56%	71%
York	89%	88%	0%	0%	0%	0%
Eastmount	70%	90%	43%	45%	67%	69%
Elmwood	87%	93%	71%	73%	64%	55%
Highland	96%	95%	40%	33%	30%	36%
Hughson	81%	95%	75%	79%	81%	81%
Kenilworth	78%	91%	57%	100%	56%	50%
Mohawk	82%	85%	51%	100%	56%	59%
Mountain	87%	91%	66%	100%	64%	57%
Ottawa	81%	89%	69%	100%	56%	76%
Parkdale	97%	100%	55%	100%	44%	100%
Spadina	89%	88%	54%	68%	48%	79%
Strouds	89%	85%	63%	70%	17%	37%
Wellington	87%	85%	50%	100%	64%	59%
Wentworth	96%	90%	75%	82%	79%	73%
Whitney	94%	92%	56%	65%	38%	43%

v) The factors that are used to assign ACA for substations' civil structures (the 'Site and Civil' component) are identified in the 2010 SACA provided in response to part 2di) and are as follows:

1) Building and Structure
2) Fences and Gates
3) Signage
4) Grounding
5) Security
6) Fire
7) Outside Access to Equipment
8) Emergency Egress from Building
9) Basement Drainage
10) Building Utilities
11) Gravel Condition in Switch Yard
12) Driveway Condition
13) Animal/Pest Issues
14) Weed and Vegetation Control
15) Switch Yard lighting
16) Buildings age
17) Building's Performance Record

vi) Horizon Utilities has incorporated automated switches to support distribution automation in projects over the 2015 to 2019 Test Years. Automated devices will be installed at feeder tie points and strategic sectionalizing points.

vii a) Horizon Utilities provides the capital expenditure per year per system component for each substation and feeders for the 4kV and 8kV Renewal Program for 2014-2019 in Table 4 attached as "BOMA-2-dviia_Table 4_Expenditure by Component". The capital expenditure for each system component is the # of components installed at the standard unit cost. The total capital expenditures for each project will not equal that identified in 2-AA. The capital expenditures in Table 4 exclude removal costs, costs of minor system components, restoration costs, management supervision and project overhead costs such as engineering design and project drafting. These costs are not allocated to major system components as identified by BOMA but are included in the overall project costs identified in Tables 1 and 2 in Appendix A of the DSP filed as Appendix 2-4 of Exhibit 2.

Horizon Utilities identifies the assets which are (i) being replaced with other assets ("RR") and (ii) being removed and not replaced ("RNR"), by year for the planned renewal/conversion in Table 5 below. Table 5 does not include assets which are incremental installations.

There are no interim upgrades required in the 2014 to 2019 time period.

Table 5

Substation	Project Name	Asset	2014		2015		2016		2017		2018		2019	
			RR	RNR	RR	RNR	RR	RNR	RR	RNR	RR	RNR	RR	RNR
Aberdeen	AB-F5 Renewal - Dundurn Street	Poles							91	0				
		Transformers							37	0				
		Devices/Switches							10	0				
		Overhead Conductor - Primary (m)							1000	0				
		Overhead Conductor - Secondary (m)							4500	0				
		Underground Cable - Primary (m)							100	0				
	AB-F2 & AB-F4 Renewal - Aberdeen East	Poles									98	0		
		Transformers									24	0		
		Devices/Switches									10	0		
		Overhead Conductor - Primary (m)									2000	1000		
		Overhead Conductor - Secondary (m)									3500	0		
		Underground Cable - Primary (m)									100	0		
	AB-F2 Renewal - Bold Street	Poles											55	0
		Transformers											11	0
		Devices/Switches											3	0
		Overhead Conductor - Primary (m)											500	0
		Overhead Conductor - Secondary (m)											2000	0
		Underground Cable - Primary (m)											20	280
Baldwin	BD-F1 Renewal - Cross Street	Poles									36	15		
		Transformers									15	0		
		Devices/Switches									15	0		
		Overhead Conductor - Primary (m)									2100	400		
		Overhead Conductor - Secondary (m)									1700	500		
		Underground Cable - Primary (m)									0	0		
	BD-F1 Renewal - Alma Street and	Poles											65	0
		Transformers											14	0
		Devices/Switches											16	0
		Overhead Conductor - Primary (m)											2500	3500
		Overhead Conductor - Secondary (m)											2500	0
		Underground Cable - Primary (m)											0	0
	BD-F2 Renewal	Poles											70	0
		Transformers											16	0
		Devices/Switches											15	0
		Overhead Conductor - Primary (m)											4500	0
		Overhead Conductor - Secondary (m)											2600	0
		Underground Cable - Primary (m)											0	0
Caroline	CA-F4	Poles	46	0										
		Transformers	15	0										
		Devices/Switches	0	0										
		Overhead Conductor - Primary (m)	1500	0										
		Overhead Conductor - Secondary (m)	1765	0										
		Underground Cable - Primary (m)	0	900										
Central	CE-F4 Renewal - Hunter/Stinson Street	Poles			67	0								
		Transformers			30	5								
		Devices/Switches			12	0								
		Overhead Conductor - Primary (m)			500	0								
		Overhead Conductor - Secondary (m)			2300	0								
		Underground Cable - Primary (m)			0	0								
	CE-F5 Renewal - Forest Ave.	Poles							55	0				
		Transformers							22	3				
		Devices/Switches							3	0				
		Overhead Conductor - Primary (m)							500	0				
		Overhead Conductor - Secondary (m)							2000	0				
		Underground Cable - Primary (m)							300	0				
	CE-F10 Renewal - John Street South	Poles									50	0		
		Transformers									20	4		
		Devices/Switches									10	2		
		Overhead Conductor - Primary (m)									2000	0		
		Overhead Conductor - Secondary (m)									2000	0		
		Underground Cable - Primary (m)									0	0		
	CE-F4 Renewal - Freeman Place	Poles											22	0
		Transformers											6	0
		Devices/Switches											2	0
		Overhead Conductor - Primary (m)											750	0
		Overhead Conductor - Secondary (m)											800	0
		Underground Cable - Primary (m)											0	0
Grantham	GR-F4 Renewal	Poles			25	0								
		Transformers			15	0								
		Devices/Switches			0	0								
		Overhead Conductor - Primary (m)			400	1000								
		Overhead Conductor - Secondary (m)			0	0								
		Underground Cable - Primary (m)			0	0								
	GR-F1 Renewal - South of Facer Street	Poles					95	0						
		Transformers					33	0						
		Devices/Switches					12	0						
		Overhead Conductor - Primary (m)					2000	0						
		Overhead Conductor - Secondary (m)					3200	0						
		Underground Cable - Primary (m)					0	0						

Substation	Project Name	Asset	2014		2015		2016		2017		2018		2019	
			RR	RNR	RR	RNR	RR	RNR	RR	RNR	RR	RNR	RR	RNR
Grantham	GR-F2 Renewal - West of Vine Avenue	Poles					65	0						
		Transformers					17	0						
		Devices/Switches					5	0						
		Overhead Conductor - Primary (m)					1000	1000						
		Overhead Conductor - Secondary (m)					2600	0						
		Underground Cable - Primary (m)					0	0						
	GR-F2 Renewal - East of Vive Avenue	Poles							50	0				
		Transformers							13	0				
		Devices/Switches							0	0				
		Overhead Conductor - Primary (m)							1500	500				
		Overhead Conductor - Secondary (m)							2600	0				
		Underground Cable - Primary (m)							100	0				
Highland	H1-F3 Renewal - Governor's Road	Poles			94	4								
		Transformers			28	2								
		Devices/Switches			0	0								
		Overhead Conductor - Primary (m)			3600	1400								
		Overhead Conductor - Secondary (m)			1000	0								
		Underground Cable - Primary (m)			0	0								
	H1-F2 Renewal - Conversion to 2D7X	Poles							34	0				
		Transformers							13	0				
		Devices/Switches							0	0				
		Overhead Conductor - Primary (m)							0	1000				
		Overhead Conductor - Secondary (m)							2400	0				
		Underground Cable - Primary (m)							0	0				
John	JN-F1 Renewal, Part 1	Poles									95	5		
		Transformers									22	0		
		Devices/Switches									7	0		
		Overhead Conductor - Primary (m)									2500	300		
		Overhead Conductor - Secondary (m)									3100	0		
		Underground Cable - Primary (m)									0	0		
	JN-F1 Renewal, Part 2	Poles											165	10
		Transformers											54	11
		Devices/Switches											19	0
		Overhead Conductor - Primary (m)											6750	0
		Overhead Conductor - Secondary (m)											9100	0
		Underground Cable - Primary (m)											0	0
	JN-F2 Renewal	Poles											55	20
		Transformers											20	0
		Devices/Switches											15	0
		Overhead Conductor - Primary (m)											3200	1800
		Overhead Conductor - Secondary (m)											2000	0
		Underground Cable - Primary (m)											0	0
Strouds	ST-F6 Renewal - Part 1, 2, & 3	Poles	94	0										
		Transformers	39	0										
		Devices/Switches	0	0										
		Overhead Conductor - Primary (m)	1500	0										
		Overhead Conductor - Secondary (m)	3000	0										
		Underground Cable - Primary (m)	30	0										
	ST-F7 Renewal - Part 1	Poles			30	0								
		Transformers			15	1								
		Devices/Switches			0	0								
		Overhead Conductor - Primary (m)			2000	0								
		Overhead Conductor - Secondary (m)			1200	0								
		Underground Cable - Primary (m)			0	0								
	ST-F7 Renewal - Part 2	Poles					70	0						
		Transformers					22	0						
		Devices/Switches					6	0						
		Overhead Conductor - Primary (m)					0	0						
		Overhead Conductor - Secondary (m)					2500	0						
		Underground Cable - Primary (m)					0	0						
	ST-F2 & ST-F6 Renewal	Poles							110	0				
		Transformers							25	0				
		Devices/Switches							12	0				
		Overhead Conductor - Primary (m)							1000	0				
		Overhead Conductor - Secondary (m)							2800	0				
		Underground Cable - Primary (m)							0	0				
	ST-F3 & ST-F4 Renewal	Poles									200	0		
		Transformers									71	4		
		Devices/Switches									12	0		
		Overhead Conductor - Primary (m)									2000	0		
		Overhead Conductor - Secondary (m)									7000	0		
		Underground Cable - Primary (m)									500	0		

Substation	Project Name	Asset	2014		2015		2016		2017		2018		2019	
			RR	RNR	RR	RNR	RR	RNR	RR	RNR	RR	RNR	RR	RNR
Vine	VE-F5 Renewal	Poles			63	0								
		Transformers			21	0								
		Devices/Switches			0	0								
		Overhead Conductor - Primary (m)			1500	0								
		Overhead Conductor - Secondary (m)			2000	0								
		Underground Cable - Primary (m)			0	0								
	VE-F5 Renewal - West of Haynes Avenue	Poles					61	0						
		Transformers					31	3						
		Devices/Switches					20	0						
		Overhead Conductor - Primary (m)					1500	500						
		Overhead Conductor - Secondary (m)					2600	0						
		Underground Cable - Primary (m)					0	0						
	VE-F3 Renewal	Poles							10	0				
		Transformers							4	0				
		Devices/Switches							12	0				
		Overhead Conductor - Primary (m)							400	0				
		Overhead Conductor - Secondary (m)							0	0				
		Underground Cable - Primary (m)							100	200				
	VE-F1 Renewal - North of Queenston Street	Poles							46	0				
		Transformers							15	1				
		Devices/Switches							6	3				
		Overhead Conductor - Primary (m)							1000	1000				
		Overhead Conductor - Secondary (m)							2000	0				
		Underground Cable - Primary (m)							0	0				
	VE-F4 Renewal - Welland and North Street	Poles							60	0				
		Transformers							24	0				
		Devices/Switches							20	0				
		Overhead Conductor - Primary (m)							1700	300				
		Overhead Conductor - Secondary (m)							2500	0				
		Underground Cable - Primary (m)							0	0				
	VE-F1 Renewal - Queenston Street	Poles							60	0				
		Transformers							19	0				
		Devices/Switches							20	0				
		Overhead Conductor - Primary (m)							1000	0				
		Overhead Conductor - Secondary (m)							2000	0				
		Underground Cable - Primary (m)							0	0				
Whitney	WH-F1 Renewal	Poles	140	0										
		Transformers	64	2										
		Devices/Switches	12	3										
		Overhead Conductor - Primary (m)	4450	0										
		Overhead Conductor - Secondary (m)	4860	0										
		Underground Cable - Primary (m)	0	0										
	WH-F3 Renewal	Poles			142	0								
		Transformers			37	0								
		Devices/Switches			0	0								
		Overhead Conductor - Primary (m)			3000	0								
		Overhead Conductor - Secondary (m)			3000	0								
		Underground Cable - Primary (m)			0	0								
	WH-F3 Renewal - Rear Lot	Poles			4	0								
		Transformers			10	0								
		Devices/Switches			0	0								
		Overhead Conductor - Primary (m)			400	500								
		Overhead Conductor - Secondary (m)			400	1600								
		Underground Cable - Primary (m)			0	0								
	WH-F5 Renewal - Main Street West	Poles					10	10						
		Transformers					20	25						
		Devices/Switches					2	4						
		Overhead Conductor - Primary (m)					2000	2000						
		Overhead Conductor - Secondary (m)					500	0						
		Underground Cable - Primary (m)					0	0						
	WH-F6 - Ewen Street	Poles							94	0				
		Transformers							22	0				
		Devices/Switches							1	0				
		Overhead Conductor - Primary (m)							2000	0				
		Overhead Conductor - Secondary (m)							3500	0				
		Underground Cable - Primary (m)							0	0				
	WH-F6 - Whitney Ave.	Poles									120	0		
		Transformers									37	0		
		Devices/Switches									12	0		
		Overhead Conductor - Primary (m)									2800	0		
		Overhead Conductor - Secondary (m)									4700	0		
		Underground Cable - Primary (m)									0	0		
York	YK-F1 Renewal - York Road	Poles									5	0		
		Transformers									5	0		
		Devices/Switches									4	1		
		Overhead Conductor - Primary (m)									500	1000		
		Overhead Conductor - Secondary (m)									150	350		
		Underground Cable - Primary (m)									0	0		

vii (b) Horizon Utilities has provided operating area specific information in the DSP, Exhibit 2, Tab 6, Appendix 2-4, pages 235-244, for 4kV and 8kV Renewal. Additional details on the specific projects are provided in Exhibit 2, Tab 6, Appendix 2-4, Appendix G on the following pages:

- 2015
    - Grantham pages 56 and 60
    - Highland pages 24 and 28
    - Strouds page 44
    - Vine page 64
    - Whitney page 48 and 52
- 2016
    - Central page 134
    - Grantham pages 164, 168, and 172
    - Strouds page 156
    - Vine page 184 and 188
    - Whitney page 160
- 2017
    - Aberdeen page 238
    - Central page 242
    - Highland page 254
    - Strouds page 278
    - Vine page 298 and 306
    - Grantham page 290
    - Whitney page 286

- 2018
    - Aberdeen page 343
    - Baldwin page 347
    - Central page 355
    - John page 379
    - Strouds page 387
    - Whitney page 349
    - York page 403
- 2019
    - Aberdeen page 442
    - Baldwin pages 446 and 450
    - Central page 454
    - John pages 477 and 481
    - York page 489

viii) Horizon Utilities provides the substations for which investments in the 4kV and 8kV Renewal Program (i) were made in 2008 to 2013 and (ii) were planned in the 2014 Bridge Year in Table 6 below.

Table 6: 4kV and 8kV Renewal Program Investment 2008 – 2014

Substation	2008	2009	2010	2011	2012	2013	2014 Bridge Year
Aberdeen S/S				AB-3 Feeder			
Caroline S/S	CA-6 Feeder	CA-8 Feeder	CA-2 Feeder	CA-3 Feeder	CA-5 Feeder		CA-4 Feeder
Halson S/S	HA-2 Feeder	HA-F1 Feeder					
Hughson S/S			HU-10 Feeder	HU-8 Feeder	HU-7 Feeder HU-6 Feeder	HU-5 Feeder HU-9 Feeder HU-11 Feeder	
Wellington S/S		WL-5 Feeder					
Taylor S/S			TA-F1 Feeder		TA-F3 Feeder TA-F2 Feeder		
Webster S/S		WB-1 Feeder		WB-2 Feeder			
Welland S/S	WE-F3 Feeder			WE-F2 Feeder		WE-F1 Feeder	WE-F4 Feeder
Whitney S/S							WH-1 Feeder
Strouds S/S							ST-6 Feeder

Horizon Utilities cannot demonstrate the impacts on outage frequency and duration, and total repair cost for prior and post conversion for the areas listed above. Pre-conversion outage information is available for a substation or substation feeder. Post-conversion outage information is not available. Substation connected feeders, when converted to a higher voltage system, are connected to multiple existing feeders on the higher voltage distribution system. A one to one mapping of data from pre to post conversion is not possible. Horizon Utilities does not record total repair costs at the substation feeder level and as such cannot identify the total repair costs pre and post conversion.

e) Horizon Utilities is proposing to decommission 28 substations with higher voltage lines over a 40-year term because it is more prudent than renewing and maintaining the substations and distribution assets at the current voltage. Generally, utilities today install higher voltage lines because at the higher voltage levels line losses are lower and it avoids the installation of costly substation assets that are not required since the higher voltage feeders can serve a large service area. The move to higher voltage lines by utilities is not new but was made possible by technological advancements and reduction of costs for insulating materials and availability of higher rated equipment over the last several decades. If one were to design a new electric distribution system one would not design a system that is based on a less efficient lower voltage and a higher cost due to substation assets.

The 4kV and 8kV Renewal Plan involves the renewal of Horizon Utilities' distribution systems and substation assets that are nearing or past end-of-life. It allows the decommissioning of Horizon Utilities' 28 substation assets over the life of the plan.

Horizon Utilities considered two options to renew these assets as identified on page 236 of the DSP filed as Appendix 2-4 of Exhibit 2:

(i) convert the 4kV and 8kV distribution system to a higher voltage; or

(ii) maintain the 4kV and 8kV distribution systems including 28 substations

Horizon Utilities chose to convert the 4kV and 8kV distribution system to a higher voltage to avoid the cost of the investment in the renewal of the substations. The proposed investments in the 4kV and 8kV Renewal Program will allow nine substations to be decommissioned between 2015 and 2019. The decommissioning of these nine substations will result in the avoided capital substation renewal investment of $22,500,000. Whether the area is converted from 4kV or 8 kV to a higher voltage, the fundamental fact is that the distribution assets (the poles and wires) need to be replaced as they have reached their end of life. The total avoided substation renewal investment over the remaining 35 years of the plan is $70,000,000 for all 28 substations.

The 4kV and 8kV Renewal Program requires the substations in the Hamilton East and Hamilton Mountain operating areas to remain in service for the majority of the 40-year renewal term. The substations renewal investments referred to by Kinectrics on page 6 of the Kinectrics' 2013 Asset Condition Assessment ("ACA") were directed at the substations in these two operating areas; they were identified in Horizon Utilities' last CoS application (EB-2010-0131). As identified by Kinectrics on page 33 of the ACA, these investments were effective in improving the overall health of the substation asset groups as compared to the previous asset condition assessments. This was the intended benefit of the investments made in 2010 to 2013.

The rationale for Horizon Utilities' 4kV and 8kV Renewal Program is on pages 235-244 of the DSP filed as Appendix 2-4 in Exhibit 2, Tab 6.

f) Horizon Utilities provides a more detailed explanation of the advantages of converting to a higher voltage below:

- Redundancy is a form of resilience that ensures system availability in the event of an asset failure. Conversion to a higher voltage provides more redundancy as follows:
    - o Horizon Utilities' experience, based on its distribution system configuration, is the higher the voltage level, the greater the number of feeder ties/interconnections. The average 4kV or 8kV feeders have 1-2 tie points, where 13.8kV or 27.6kV feeders have 4-5 tie points on average. This provides increased operational contingencies in the event of a failure.
    - o The lower voltage system is characterized by shorter feeder lines which are localized and often have isolated service areas. By converting to the higher voltage systems, customers connected to the lower voltage system are no longer part of a local or isolated network as they become part of the larger, more ubiquitous and better resourced voltage systems.
- Interoperability is the capability of neighbouring systems to interconnect and operate with one. Interoperability is dependent upon the uniformity of system components and characteristics (i.e. voltages). Conversion to a higher voltage provides better operability as follows:
    - o Voltages at different levels cannot be connected and as such parts of the distribution system can become stranded. In this case, the neighbouring system cannot be used for redundancy. Conversion to a uniform voltage also allows for more effective inventory management, uniformity on design, construction, and material standards.
- No intermediary substation assets are required
    - o Conversion of 4kV and 8kV to 13.8kV allows for the elimination of 4kV/8kV substation assets.

g) Horizon Utilities does not have line loss data at the station or feeder level. Horizon's need to renew the 4kV and 8 kV assets was not justified on lowering line losses. Horizon's need to renew these assets is based on their condition and the option to convert to a higher voltage levels is both cheaper and operationally more effective (refer to answers above) vs. replacing the assets at the existing voltage level.

That being said, the extent to which line losses for 4kV or 8kV voltages are higher than for 13.8kV or 27.6 kV voltages is a statement of fact and is a well-accepted and naturally occurring physical phenomenon that can be expressed formulaically. It is related to Ohm's Law and the law of conservation of energy.

The energy or power delivered from point A to point B over a conductor is the product of current and voltage (P = V x I). The higher the line voltage, the lower the line current required to deliver the same amount of power.

Line losses are a product of line resistance ("R") and the square of the line current ("I") (i.e. Line loss = R X I^2). The higher the line voltage, the lower the line current will be, and correspondingly the lower the line losses.

BOMA-2_Attch_1_2008 Renewal Plan

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Horizon Utilities Corporation

Distribution System Conversion Plan

4.16 kV and 8.32 kV Voltage Level

2008 – 2036

Prepared By:
Network Planning and Operating, 2007

Executive Summary

Horizon Utilities Corporation distributes electricity to around 231,000 customers in the Hamilton and St. Catharines area. Among the entire customer base, around 82,000 customers are served from the 4.16 kV and 8.32 kV voltage levels. The distribution system in these parts of the service area was mainly created sometime around the 1950s, which implies that the distribution assets are nearing their end of life. A combination of growing population in the area demanding increase in capacity and aging infrastructure makes it imperative for us to replace these assets in the near future. From an economic and capacity planning perspective, it is more beneficial for Horizon Utilities to replace the assets to the higher voltage levels of 13.8 kV or 27.6 kV from the 4.16 kV and 8.32 kV voltage levels. This 4.16 kV and 8.32 kV system conversion plan is a detailed study on the distribution system to justify and prioritize the decommissioning and capital reinvestment requirements in the Horizon Utilities Corporation service area.

The 4.16 kV and 8.32 kV voltage level conversion plan contains a specific order of suggested feeders to be converted in the next 20 years and a suggested decommissioning year for each of the 30 substations. Along with each suggested feeder due for conversion between 2009 and 2011, an explanation is provided detailing the reason of conversion, any issues that need to be considered during the design and construction process and an estimated cost of conversion. These explanations are provided to give a high level framework for the design and construction group during the undertaking of the project. A similar methodology for recommendations has been used to derive a conversion order and year for the rest of the feeders for the years 2012 to 2026.

Based on the results of the study, the distribution system fed from the following substations will be converted from the 4.16 kV to the 13.8 kV voltage level or from the 8.32 kV to the 27.6 kV voltage level in the following order between 2009 and 2026:

1. Webster
2. Grantham
3. Vine
4. Elmwood
5. Aberdeen
6. Taylor
7. Welland
8. Ottawa
9. Bartonville
10. Stroud’s Lane
11. Whitney
12. Mohawk
13. Mountain
14. Central
15. Caroline
16. Wellington
17. Wentworth
18. Hughson
19. Spadina
20. Cope
21. Parkdale
22. Eastmount
23. Kenilworth
24. Dewitt
25. York
26. Deerhurst
27. Galbraith
28. Baldwin
29. John
30. Highland

Refer to Figures 3-4 in Section 4 for a visual exemplification of the conversion rankings in terms of the geographical location of the Horizon Utilities substations based on the Geographic Information System data.

Table of Contents

1. Introduction

Horizon Utilities Corporation is the third largest municipally owned electricity distribution company in Ontario. It provides electricity and related utility services to over 231,000 residential and commercial customers in Hamilton and St. Catharines. The electricity distribution system entails several voltage levels ranging from the 4.16 kilovolts (kV) to a maximum of 27.6 kV.

Although the majority of the customer base in Hamilton and St. Catharines is served from the 13.8 kV and the 27.6 kV distribution voltage levels, there is still around 82000 customers who are served from the 4.16 kV and 8.32 kV levels. These areas include 30 substations among which 26 are in Hamilton and 4 are in St. Catharines. The conversion projects entail an upgrade of all the distribution system assets to the higher voltage standard and eventually lead to the removal of the load from the substations allowing them to be decommissioned.

The long-term vision of Horizon Utilities Corporation is to phase out the substations by converting the service areas to either of the 13.8kV or 27.6 kV voltage levels. The conversion plan will provide Horizon Utilities Corporation with a decision model to justify and prioritize capital projects by organizing capital investments in different parts of the 4.16 kV and 8.32 kV voltage service areas thus allowing us to have predictable capital expenditure levels for the next 25 years and accordingly achieve higher system reliability levels in the future.

In these service areas, the assets are nearing the end of life. This negatively affects our reliability matrices and puts us at the risk of unanticipated and high capital expenditure levels. Also, some parts of the distribution system within the 4.16 kV and the 8.32 kV voltage levels are being operated at maximum capacity with restricted backup capabilities in case of unplanned outage. Converting these parts of the system will result in lower maintenance costs, higher reliability indices and increased customer satisfaction.

Based on the information available at the time when this plan is created, the order of the feeders to be converted is suggested to be followed. But it is also essential that the engineer recognizes the scope of the conversion plan to be a high level outline of a detailed analysis required on individual feeders at the time the project is issued. It is suggested that any additional information available at the time of conversion that might affect the outcome and scope of the conversion project is utilized.

2. Conversion Plan

The list of feeders with associated explanation for the reasons of conversion and special considerations required during conversion is provided for the years 2009 to 2011. For the years 2012 – 2026 the feeders, the same methodology has been used to derive the order of conversion. It is suggested that before the project is issued, a quick feasibility analysis is conducted for the feeders in individual stations to check for change in equipment demographics, loading, backup capabilities and availability of sources around those feeders at the time of conversion. The engineer should also attend to the fact that the intention of the plan is to eliminate all 4.16 kV or 8.32 kV feeders fed from each substation one after the other for higher economic returns and efficient resource allocation. This pattern is followed as closely as possible in the conversion plan.

2.1 Conversion Plan – Year 2009

The following feeders are recommended for conversion for 4.16 kV to 13.8 kV voltage level or from 8.32 kV to 27.6 kV voltage level in 2009. The feeders to be converted are Grantham F4, Grantham F2 and Grantham F1 fed from Grantham M.S. followed by feeders Vine F3, Vine F1, Vine F5 and Vine F4 from Vine M.S. Webster 1 feeder load is suggested to be transferred over to the Deerhurst 3 feeder. Webster, Grantham and Vine substations are suggested for decommissioning.

Note: Although the order of the feeder conversion is suggested, it is not necessary to be followed strictly. It is upon the design engineer's judgment to modify it based on additional information available at the time of conversion.

i. Webster 1 – Load Transfer

This is the first feeder suggested to act upon as part of the conversion plan. The transformers are among the oldest in our system (e.g. built – 1952). The Oil Analysis results have identified the transformers to have been exposed to extremely high heat and have caused deterioration in the internal insulation. Based on the data available of the distribution system, it appears to be in decent shape. So, it is suggested that we transfer the load from Webster 1 to one of the Deerhurst feeders. The analysis on whether Deerhurst would be able to sustain the transferred load from Webster is underway. Digital Recording Ammeters (DRA) are being used to read the actual load on the Deerhurst feeders. Upon completion of this process, Webster Substation would be available for decommissioning.

ii. Grantham F4

Grantham F4 is suggested to be the first feeder in Grantham to be converted based on the lack of backup availability and cost affectivity. Grantham F2 is the only backup for Grantham F4. The distribution assets are nearing their end of life with average ages of transformers and poles being 38.8 and 44.3, respectively.

Although there is a lower impact of failure than Grantham F1 and Grantham F2, converting Grantham F4 after the other two feeders will cause it to have no backup after Grantham F2 is converted. Grantham F2 can be backed up by Grantham F1 while Grantham F4 is converted. Bunting M62, a 13.8 kV overhead conductor runs along the main feeder span along Grantham F2 and is the possible 13.8 kV source.

Grantham F4 Estimated Conversion Cost - $657,958

iii. <u>Grantham F2</u>

Grantham F2 has most of its distribution assets nearing the end of life with high probability of failure. A portion of Grantham F3 has been transferred over to Grantham F2 and this portion needs to be converted along with Grantham F2. The average ages of transformers and poles are 44.1 and 28.0, respectively. With 640 commercial customers and 118 residential customers connected to this feeder, it would have a high impact in case of failure. With Grantham F4 converted, Grantham F2 has only Grantham F1 as backup. While Grantham F2 conversion project is in progress, Grantham F1 will be backed up by Vine F3. The new 13.8 kV overhead will be extended from the Bunting M62 feeder.

Grantham F2 Estimated Conversion Cost - $1,633,096

iv. <u>Grantham F1</u>

Grantham F1 has most of its distribution assets nearing their end of life. With average ages of transformers and poles being 38.1 and 23.6, respectively and poor asset condition there is a high probability of asset failure and unanticipated capital expenditure. 726 commercial customers and 33 residential customers served from this feeder attribute to the high impact in case of failure. While Grantham F1 is converted to the 13.8 kV voltage level, its only backup in the form of Vine F3 requires another backup. The suggested solution to this is to install a temporary tie switch between Vine F4 and Vine F3 until Vine F3 is converted. As Vine F4 has high loading there might be an issue backing Vine F3 with Vine F4 and in the case this is identified at the time of the project, 4.16 kV Grantham F1 feeder needs to be retained for backup. The 13.8 kV feeders available as source for Grantham F1 are Bunting M77 and Bunting M62. This is the last Grantham feeder to be converted and after the conclusion of this project, the 4.16 kV voltage level distribution system supplied from the Grantham M.S. will be completely converted to the 13.8 kV voltage level. This will allow us to convert an entire 4.16 kV voltage distribution system connected to the Grantham M.S. and make it available for decommissioning.

Grantham F1 Estimated Conversion Cost - $1,523,047

v. Vine F3

This is the first Vine Feeder suggested for conversion to the 13.8 kV voltage level. The assets connected to the feeder are near their end of life. The average ages of transformers and poles are 35.9 and 26.9, respectively. As Vine F3 and Vine F4 are heavily loaded, retaining them as temporary backups will create restrictions for transferring the load in case of failure. The 13.8 kV feeders available as sources are Bunting M76 and Bunting M77.

Vine F3 Estimated Conversion Cost - $1,453,310.32

vi. Vine F1

Vine F1 is the second feeder from Vine M.S. suggested for conversion to the 13.8 kV voltage level due to most of the distribution assets connected to it are nearing their end of life. The average ages of transformers and poles connected to the Vine F1 feeder are 38.1 and 24, respectively. There are no anticipated backup issues due to conversion of Vine F1 as the Vine F5 load can be transferred over to Vine F4 if required. Converting Vine F1 will further provide an easily accessible 13.8 kV source for Vine F5 to be connected to when it is converted. Glendale M24 is the available 13.8 kV overhead source for conversion.

Vine F1 Estimated Conversion Cost - $1,279,303.85

vii. Vine F5

Vine F5 is the suggested for conversion from the 4.16 kV to the 13.8 kV voltage level because of the distribution assets connected to the feeder are nearing their end of life. The average age of transformers is 34.9 years and of poles is 29.0 years. Vine F5 has Vine F4 and Welland F4 as backups. After Vine F5 is converted Vine F4 will be backed up by Welland F1. Welland F4 will require a separate backup and it is suggested that a tie switch is installed between Welland F4 and Welland F3. As these feeders are not heavily loaded at the time when this plan is formed, this backup strategy is feasible. At the time of conversion it is suggested that the loading and backup capability is inspected for feasibility. Glendale M24, a 13.8 kV voltage feeder should be extended to eliminate Vine F5.

Vine F5 Estimated Conversion Cost - $1,057,611.60

viii. Vine F4

Vine F4 is the last suggested 4.16 kV distribution feeder connected to Vine M.S. to be converted. Based on a combination of higher economies of scale and high impact of failure, this is identified as an effective conversion project. This will allow us to convert an entire 4.16 kV voltage distribution system connected to the Vine M.S. and decommission the substation as part of a continuous project. The average ages of transformers and poles are 40.8 and 26.9, respectively. There are 682 commercial customers and 103 residential customers connected to this feeder. With Vine F5 converted previously, Welland F1 is the only backup for Vine F4. After the completion of Vine F4 conversion, Welland F1 will be backed up by Welland F2. Carlton M7, a 13.8 kV feeder available in the back end of Vine F4, should be extended as part of conversion. Converting this feeder upgrades the entire 4.16 kV system connected to Vine M.S. to the 13.8 kV level and makes the sub-station available for decommissioning.

Vine F4 Estimated Conversion Cost - $1,636,898.21

2.2 Conversion Plan – Year 2010

The following feeders are recommended for conversion for 4.16 kV to 13.8 kV voltage level or from 8.32 kV to 27.6 kV voltage level in 2009. The feeders to be converted are Elmwood 4, Elmwood 5, Elmwood 10, Elmwood 2, Elmwood 8, Elmwood 9, Elmwood 3 and Elmwood 7 from Elmwood substation followed by feeders Aberdeen 3 from Aberdeen substation. Elmwood substation is suggested for decommissioning.

Note: Although the order of the feeder conversion is suggested, it is not necessary to be followed strictly. It is upon the design engineer's judgment to modify it based on additional information available at the time of conversion.

i. Elmwood 4

A combination of aging assets and heavy impact of failure justifies converting Elmwood 4 from the 4.16 kV voltage level to the 13.8 kV voltage level. This would replace the transformers and poles with average ages of 37.8 and 43.8, respectively. The 35 commercial customers and 451 residential customers fed from this feeder contribute towards the high impact in case of failure. Elmwood 4 is backed up by Wellington 6 and Elmwood 7. Unless there is a substantial increase in peak loading for Wellington 6 and Elmwood 7, this conversion project will not negatively affect the backup strategy for these two feeders. 0622X is the 13.8 kV feeder that should be extended to complete the voltage conversion.

Elmwood 4 Estimated Conversion Cost - $1,437,512.55

ii. Elmwood 5 and 10

The distribution assets connected to Elmwood 5 and Elmwood 10 is nearing their end of life. These two feeders are suggested for conversion together because of two reasons. Firstly, they back each other up and so, instead of backing up one of the feeders by installing another tie-switch with a different feeder, converting both of them at the same time is financially more beneficial. Secondly, both the feeders lie on the same geographical path making it feasible from a design perspective. The average ages of transformers and poles are 34.7 and 40.9 years, respectively. These two feeders combined feed 6 commercial customers and 608 residential customers. The 13.8 kV level feeder 0622X should be extended to convert the areas to the higher voltage level.

Elmwood 5 Estimated Conversion Cost – $1,306,009.02
Elmwood 10 Estimated Conversion Cost – $464,901.34

iii. Elmwood 2

This feeder is suggested for conversion from the 4.16 kV voltage level to the 8.32 kV voltage level primarily because of its limited backup capability. Elmwood 2 has Elmwood 8 as its only back-up. If Elmwood 8 is converted before, Elmwood 2 will have no backup available. The average ages of transformer and poles connected to this feeder are 28.8 and 38.4, respectively. This indicates that these assets are nearing their end of life. There are 4 commercial and 291 residential customers fed from this feeder. After Elmwood 2 is converted, Elmwood 8 will be backed up by Elmwood 9. The 13.8 kV level feeder, 491X, which almost runs along the entire length of Elmwood 2 would be the new feeder for the converted area.

Elmwood 2 Estimated Conversion Cost - $926,093.80

iv. Elmwood 8

Aging assets that need to be replaced is the primary reason for conversion of this feeder from the 4.16 kV to the 13.8 kV voltage level. The average age of transformers and poles connected to this feeder are 33.6 and 40.0, respectively. As these assets need to be replaced in the near future through the asset renewal program, converting to the higher voltage level would provide us with the ability to serve more customers if demand increases in this area. Elwood 9 is currently backed up by Elmwood 8. After Elmwood 8 is converted to the higher voltage level, Elmwood 9 will be backed up by Wellington 10 with no perceived loading issues. 13.8 kV feeders 481X and 4111X can be extended to feed the areas previously fed from the Elmwood 8 feeder.
Elmwood 8 Estimated Conversion Cost - $1,277,960.01

v. Elmwood 9

The distribution assets connected to Elmwood 9 are also nearing their end of life. It is more beneficial to upgrade the entire feeder from the 4.16 kV voltage level to the 13.8 kV voltage level through conversion than replacing portion of the assets through renewal. The average ages of transformers and poles are 30.0 and 45.0, respectively, stressing the fact that they have almost reached their end of lives. Wellington 10, the backup for Elmwood 9, will be backed up by Wellington 8 after the voltage conversion eliminated Elmwood 9. There are 10 commercial customers and 440 residential customers connected to this feeder. The 13.8 kV feeder 0622X will be extended to replace the Elmwood 9 feeder.

Elmwood 9 Estimated Conversion Cost - $943,044.27

vi. Elmwood 3 and Elmwood 7

As these two feeders are backups for each other, converting them to the 13.8 kV voltage level together is suggested. As the rest of the feeders connected to the sub-station have been converted already, there are no other backups available around in the area. The average ages of transformers and poles are 33.2 and 43.44 years, respectively. As this would be a major project replacing around 55 transformers and 274 poles, it is suggested that the design and construction work is completed in phases. The combined project will upgrade 13 commercial and 684 residential customers from the 4.16 kV level to the 13.8 kV level. The 0622X feeder is the suggested feeder to be extended to supply these areas at the higher voltage level.

Elmwood 3 Estimated Conversion Cost – $1,281,400.48
Elmwood 7 Estimated Conversion Cost – $1,101,978.71

vii. Aberdeen 3

Aberdeen 3 is the first 4.16 kV feeder recommended for conversion to the 13.8 kV voltage level. A combination of aging assets and retaining adequate backup capability are the primary reasons for this choice. The average ages of transformers and poles are 31.8 and 45.8, respectively. This shows that these assets are nearing their end of life. Aberdeen 5 is the only backup for this feeder. So, it is recommended to be converted the earliest. After Aberdeen 3 is converted to the 13.8 kV voltage level, Aberdeen 5 will be backed up by Aberdeen 2 and Stroud’s Lane 6 Feeders. Feeder 491X will provide the necessary 13.8 kV overhead source for extension.

Aberdeen 3 Estimated Conversion Cost - $1,071,982.48

2.3 Conversion Plan – Year 2011

The following feeders are recommended for conversion for 4.16 kV to 13.8 kV voltage level or from 8.32 kV to 27.6 kV voltage level in 2012. The feeders to be converted are Aberdeen 1, Aberdeen 4, Aberdeen 2 and Aberdeen 5 from Aberdeen substation followed by Taylor F3, Taylor F2 and Taylor F1 from Taylor M.S. Welland F4 and Welland F3 from Welland M.S. is also suggested for conversion. Aberdeen and Taylor substations are suggested for decommissioning.

Note: Although the order of the feeder conversion is suggested, it is not necessary to be followed strictly. It is upon the design engineer's judgment to modify it based on additional information available at the time of conversion.

i. Aberdeen 1

Aberdeen 1 is the second feeder from Aberdeen Substation recommended for conversion because it has Aberdeen 2 as its solitary backup. Although the assets are in slightly better condition than the other Aberdeen feeders, it would be left without a backup if converted after the others. Another option is to install a tie-switch with another feeder for backup, but it will only be required for a short period till Aberdeen 1 is converted. The average life of transformers and poles are 28.4 and 40.5 years. There are 84 commercial and 629 residential customer services fed from this feeder, which would result to a high impact in case of failure. After the conversion of Aberdeen 1, Aberdeen 2 will be backed up by other feeders. The 13.8 kV feeder 282X is suggested as source for conversion.

Aberdeen 1 Estimated Conversion Cost - $940,284.73

ii. Aberdeen 4

A majority of the assets connected to Aberdeen 4 are nearing the end of their life. As these assets are due to be replaced through asset renewal, it would be more beneficial to completely upgrade this part of the system to the 13.8 kV level. The average age of transformers and poles are 30.8 and 48.6, emphasizing the fact that the assets are due for replacement in the near future. 12 commercial and 509 residential customers are supplied from this feeder. Caroline 5 is the only backup for Aberdeen 4. Converting this feeder will also provide a 13.8 kV source for Aberdeen 2, which is the next feeder to be converted. After the area supplied form Aberdeen 4 has been upgraded, Caroline 5 will still have Caroline 3 and Central 2 as backup. The feeders 282X and 222X should be extended to upgrade the distribution system to the 13.8 kV voltage level.

Aberdeen 4 Estimated Conversion Cost – $1,406,078.43

iii. Aberdeen 2

The distribution assets are nearing their end of life in the area. There is also a high impact in case of failure and adequate backup availability. These reasons combines makes this feeder suitable for conversion to the higher voltage level. The average life of transformers and poles are 27.3 and 51.3 years, respectively. There are 41 commercial and 724 residential customers served from this feeder. Aberdeen 5 and Caroline 3 are the backups for Aberdeen 2. After conversion, Aberdeen 5 and Caroline 3 will have other feeders to back them up. The area would be upgraded to the 13.8 kV level by extending the 282X feeder.

Aberdeen 2 Estimated Conversion Cost - $1,067,137.61

iv. Aberdeen 5

This is the last feeder from the Aberdeen substation that is recommended for upgrade. It is economically more beneficial to eliminate all the feeders from each station and eventually decommission the station to ensure that one whole area is upgraded. The average age of transformers and poles are 25.3 and 36.1 years respectively. There is also a high impact of failure as 59 commercial and 716 residential customers served from this feeder. Stroud's Lane 6, which is the backup for Aberdeen 5, will be backed up by Stroud's Lane 7 after the voltage conversion project. 222X has to be extended to upgrade the area to 13.8 kV voltage level. This will convert the entire are covered by Aberdeen substation from the 4.16 kV voltage level to the 13.8 kV voltage level making the substation available for decommissioning.

Aberdeen 5 Estimated Conversion Cost - $1,776,473.87

v. Taylor F3

Taylor F3 is the first 4.16 kV level feeders recommended from conversion to the 13.8 kV level. The distribution assets are aged and backup incapability has brought this feeder to the top of the list among Taylor M.S. feeders. The substation itself is in very poor condition with a few safety and environmental concerns that need attention. The average age of the transformers and poles are 38.8 and 33.4 years, respectively. As all 3 feeders in Taylor back each other up, eliminating the highest loaded feeder Taylor F3 is suggested as the first project. This would prevent any further backup issues in any other feeders. There are currently 976 commercial customers and 51 residential customers served from the Taylor F3 feeder. The Carleton M7 feeder is suggested to be extended to upgrade the area to the 13.8 kV voltage level.

Taylor F3 Estimated Conversion Cost - $1,704,864.14

vi. Taylor F2

The distribution assets connected to Taylor F2 are in very poor condition and are due to replaced in the near future. The average age of transformers and poles are 39.0 and 32.7 years, indicating that the assets are nearing their end of life. Through this conversion 442 commercial and 52 residential customers will be served from the 13.8 kV voltage level. Taylor F1 and Taylor F3 will back each other up after Taylor F2 has been eliminated. There is already a 13.8 kV overhead source running along the main feeder span. After the conversion 442 commercial customers and 52 residential customers will be supplied from the 13.8 kV voltage level. Carlton M7 is the suggested 13.8 kV feeder to feed the area after the project is completed.

Taylor F2 Estimated Conversion Cost - $852,819.80

vii. Taylor F1

Converting Taylor F1 would completely upgrade the area served from Taylor M.S. to the 13.8 kV voltage level. Similar to the other Taylor feeders, the distribution assets in Taylor F1 is also in very poor condition. The average age of both transformers and poles is approximately 40.0 years. This shows that these assets are due for replacement soon. It is also economically more beneficial for us to sequentially upgrade all the feeders from one station. This project, when completed, will serve another 343 commercial customers and 8 residential customers to the 13.8 kV voltage level and make Taylor M.S. available for decommissioning. The Carleton M11 feeder is to be extended to upgrade the area to the 13.8 kV voltage level.

Taylor F1 Estimated Conversion Cost - $670,849.14

viii. Welland F4 and Welland F3

Welland F4 and Welland F3 are suggested for combined conversion to the 13.8 kV level. Whether the suggestion of installing a tie switch between Welland F3 and Welland F4 during the Vine F4 conversion project was followed or not, needs to be considered during this project. If it was, then there wouldn't have been any backup issues from then to the time of the current project. Although the assets connected to these are in better condition that the other Welland feeders, it is imperative that this one is converted to the 13.8 kV level in order to have adequate backup provisions. These two feeders combined have average transformer and pole ages of 38.7 and 24.9. Upon completion of this project, another 287 commercial customers and 283 residential customers will be served from the new 13.8 kV system. The Glendale M24 feeder, originally extended to convert the area covered by Vine F5, can be extended to convert the areas covered by these two feeders.

Wellend F4 Estimated Conversion Cost – $389,050.94

Welland F3 Estimated Conversion Cost – $368,565.31

2.4 Conversion Plan – Year 2012 – 2026

The following are the feeder conversion recommendations between the years 2012 and 2026.

Conversion Plan – Year 2012

i. Welland F1 and F2, Welland F1 Estimated Conversion Cost – $1,147,152.22 and Welland F2 Estimated Conversion Cost – $1,259,998.01; These two feeders are suggested for conversion together to avoid additional expenditure required to install a tie-switch for Spadina 7 backup
ii. Mohawk 9, Estimated Conversion Cost - $1,072,463.69
iii. Ottawa 2, Estimated Conversion Cost - $773,796.97
iv. Ottawa 4, Estimated Conversion Cost - $1,089,550,78
v. Ottawa 8 and Ottawa 1, Estimated Conversion Cost - $1,543,026.17
vi. Ottawa 7 and Spadina 7, Ottawa 7 Estimated Conversion Cost - $1,172,687.11, Spadina 7 Estimated Conversion Cost - $1,050,293.58; These two feeders are suggested for conversion together to avoid additional expenditure required to install a tie-switch for Spadina 7 backup
vii. Ottawa 3, Estimated Conversion Cost - $993,582.74

Welland substation is suggested for decommissioning.

Conversion Plan – Year 2013

i. Wellington 6, Estimated Conversion Cost - $1,422,276.04
ii. Ottawa 6, Estimated Conversion Cost - $1,314,231.61
iii. Ottawa 5, Estimated Conversion Cost - $1,301,732.91
iv. Bartonville 7, Estimated Conversion Cost - $820,757.99
v. Bartonville 3, Estimated Conversion Cost - $406,424.91
vi. Bartonville 4, Estimated Conversion Cost - $1,254,024.05
vii. Wellington 2, Conversion Cost - $1,028,253.24
viii. Bartonville 1, Estimated Conversion Cost - $927,544.24
ix. Bartonville 2, Estimated Conversion Cost - $818,453.14
x. Stroud’s Lane 2, Estimated Conversion Cost - $976,995.66

Ottawa and Bartonville substations are suggested for decommissioning.

Conversion Plan – Year 2014

i. Stroud's Lane 3, Estimated Conversion Cost - $1,029,163.52
ii. Stroud's Lane 7, Estimated Conersion Cost - $1,342,577.61
iii. Wellington 9, Estimated Conversion Cost – $1,248,925.64
iv. Stroud's Lane 6, Estimated Conversion Cost - $1,188,604.43
v. Stroud's Lane 4, Estimated Conversion Cost - $1,274,117.65
vi. Whitney 3, Estimated Conversion Cost - $1,141,468.69
vii. Whitney 6 and Whitney 2, Estimated Conversion Cost – 1,816,473.81; these two are suggested for conversion together for adequate backup requirements.
viii. Wentworth 1, Estimated Conversion Cost - $1,075,933.38

Stroud's Lane substation is suggested for decommissioning.

Conversion Plan – Year 2015

i. Whitney 5, Estimated Conversion Cost - $1,398,705.51
ii. Whitney 1, Estimated Conversion Cost - $1,285,827.49
iii. Whitney 4, Estimated Conversion Cost - $1,033,843.14
iv. Mohawk 1, Estimated Conversion Cost - $1,521,593.88
v. Wentworth 9, Conversion Cost – $1,095,862
vi. Mohawk 11, Estimated Conversion Cost - $1,367,255.45; Eastmount 1 feeder needs tie-switch connected to Eastmount 7 for future backup capabilities.
vii. Mohawk 10, Estimated Conversion Cost - $1,842,030.83
viii. Mohawk 5, Estimated Conversion Cost - $667,544.93

Whitney substation is suggested for decommissioning.

Conversion Plan – Year 2016

i. Mohawk 6, Estimated Conversion Cost - $917,243.38
ii. Mohawk 3, Estimated Conversion Cost - $1,231,499.72
iii. Mohawk 2, Estimated Conversion Cost - $1,198,939.70
iv. Mountain 2 and Mountain 3, Estimated Conversion Cost - $1,781,474.00; these two feeders are suggested for conversion together to have adequate backup capability in case of failure.
v. Mountain 9, Estimated Conversion Cost - $1,350,998.16
vi. Mountain 4, Estimated Conversion Cost - $1,165,266.55
vii. Mountain 11, Estimated Conversion Cost - $54,895.94

viii. Mountain 10, Estimated Conversion Cost - $1,168,917.78
ix. Mountain 5, Estimated Conversion Cost - $815,145.77
x. Mountain 6, Estimated Conversion Cost - $1,064,079.94

Mohawk and Mountain substations are suggested for decommissioning.

Conversion Plan – Year 2017

i. Central 8, Estimated Conversion Cost - $649,532.81
ii. Central 11, Estimated Conversion Cost – $610,121.79
iii. Central 4 and Central 5, Estimated Conversion Cost - $1,753,080.94; these two feeders are suggested for conversion together to have adequate backup capability in case of failure.
iv. Central 3, Estimated Conversion Cost - $921,529.62
v. Central 10, Estimated Conversion Cost - $1,032,723.81
vi. Central 6, Estimated Conversion Cost - $674,514.79
vii. Central 1, Estimated Conversion Cost - $312,191.51
viii. Central 2, Estimated Conversion Cost - $1,046,661.98
ix. Central 9, Estimated Conversion Cost - $521,978.11
x. Hughson 5, Estimated Conversion Cost – $1,181,775.43; this feeder is required so that Caroline 4, the next feeder does not leave Hughson 5 without a backup. The alternate option of installing a tie-switch to backup Hughson 5 for another 6 years till its converted is not economical.
xi. Caroline 4, Estimated Conversion Cost - $1,316,757.22

Central Substation is provided for decommissioning.

Conversion Plan – Year 2018

i. Caroline 3 and Caroline 5, Estimated Conversion Cost – $2,606,749.56; these two feeders are suggested for conversion together to have adequate backup capability in case of failure.
ii. Caroline 6 and Caroline 8, Estimated Conversion Cost – $1,868,780.30; these two feeders are suggested for conversion together to have adequate backup capability in case of failure.
iii. Caroline 7, Estimated Conversion Cost - $1,343,889.69
iv. Caroline 2, Estimated Conversion Cost - $269,841.35; this feeder only supplies street lights
v. Wellington 11, Estimated Conversion Cost - $1,314,931.08

vi. Wellington 10, Estimated Conversion Cost - $755,732.15
vii. Wellington 1, Estimated Conversion Cost - $1,013,041.43
viii. Wellington 3 and Wellington 4, Estimated Conversion Cost – $1,914,209.64

Caroline substation is suggested for decommissioning.

Conversion Plan – Year 2019

i. Wellington 8 and Wellington 5, Estimated Conversion Cost - $2,178,407.11; these two feeders are suggested to be decommissioned to have adequate backup and avoid investment in a tie-switch installation. A portion of Wellington 5 feeder has been identified for conversion in 2008.
ii. Wentworth 5, Estimated Conversion Cost - $1,875,872.99
iii. Wentworth 11 and Wentworth 2, Estimated Conversion Cost - $1,676,295.58; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
iv. Wentworth 3 and Wentworth 4, Estimated Conversion Cost - $2,520,980.94; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
v. Wentworth 8, Estimated Conversion Cost - $815,231.43
vi. Wentworth 10, Estimated Conversion Cost – $1,465,711.21

Wellington and Wentworth substations are suggested for decommissioning.

Conversion Plan – Year 2020

i. Wentworth 6 and Wentworth 12, Estimated Conversion Cost – $1,925,176.08; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
ii. Hughson 6, Estimated Conversion Cost - $1,474,719.01
iii. Hughson 7, Estimated Conversion Cost - $1,003,834.00
iv. Hughson 9, Estimated Conversion Cost - $580,865.81
v. Hughson 11, Estimated Conversion Cost - $971,363.59
vi. Spadina 6, Estimated Conversion Cost – $1,234,108.40
vii. Spadina 4, Estimated Conversion Cost - $761,819.79
viii. Spadina 3 and Spadina 10, Estimated Conversion Cost - $1,783,955.22; these two feeders are suggested for conversion together to have adequate backup capability in case of failure

Hughson substation is suggested for decommissioning.

Conversion Plan – Year 2021

i. Spadina 1, Estimated Conversion Cost - $1,274,567.79
ii. Spadina 2 and Spadina 5, Estimated Conversion Cost - $2,495,850.51; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
iii. Cope 7, Estimated Conversion Cost - $1,381,592.08
iv. Cope 2 and Cope 8, Estimated Conversion Cost - $2,521,739.02; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
v. Cope 9, Estimated Conversion Cost - $1,725,591.17
vi. Cope 3, Estimated Conversion Cost - $727,593.77

Spadina substation is suggested for decommissioning.

Conversion Plan – Year 2022

i. Cope 1 and Kenilworth 2, Estimated Conversion Cost - $2,153,733.41
ii. Cope 5 and Cope 6, Estimated Conversion Cost - $1,431,382.26; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
iii. Cope 4 and Parkdale 3, Estimated Conversion Cost - $1,775,970.58; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
iv. Parkdale 6, Estimated Conversion Cost - $816,410.94
v. Parkdale 11, Estimated Conversion Cost - $520,394.45
vi. Parkdale 4, Estimated Conversion Cost - $1,021,811.30
vii. Parkdale 7, Estimated Conversion Cost - $884,884.16
viii. Eastmount 1, Estimated Conversion Cost - $1,125,143.69

Cope substation is suggested for conversion.

Conversion Plan – Year 2023

i. Parkdale 10 and Parkdale 5, Estimated Conversion Cost - $3,686,665.14; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
ii. Parkdale 8 and Parkdale 9, Estimated Conversion Cost - $1,760,739.03; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
iii. Eastmount 3 and Eastmount 8, Estimated Conversion Cost - $3,659,421.93; these two feeders are suggested for conversion together to have adequate backup capability in case of failure

i. Eastmount 7 and Eastmount 9, Estimated Conversion Cost - $2,229,431.77; these two feeders are suggested for conversion together to have adequate backup capability in case of failure

Parkdale substation is suggested for conversion.

Conversion Plan – Year 2024

i. Eastmount 2 and Eastmount 10, Estimated Conversion Cost - $2,395,997.89; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
ii. Eastmount 11, Estimated Conversion Cost - $1,249,996.30
iii. Kenilworth 1, Estimated Conversion Cost - $1,170,783.09
iv. Kenilworth 6, Estimated Conversion Cost - $1,059,559.26
v. Eastmount 4 and Eastmount 6, Estimated Conversion Cost - $1,946,170.51; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
vi. Kenilworth 3, Estimated Conversion Cost – $1,572,589.81

Eastmount and Kenilworth substations are suggested for decommissioning.

Conversion Plan – Year 2025

i. Kenilworth 4 and Kenilworth 5, Estimated Conversion Cost - $1,444,153.09
ii. Dewitt 2, Estimated Conversion Cost – $396,583.01
iii. Dewitt 1 and Dewitt 3, Estimated Conversion Cost - $1,588,776.53; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
iv. York 2 and York 1, Estimated Conversion Cost - $2,047,812.53; these two feeders are suggested for conversion together to have adequate backup capability in case of failure
v. Deerhurst 3, Estimated Conversion Cost - $980,540.22
vi. Deerhurst 1, Estimated Conversion Cost - $1,182,558.79

Dewitt and York substations are suggested for decommissioning.

Conversion Plan – Year 2026

i. Deerhurst 2, Estimated Conversion Cost - $571,343.87
ii. Galbraith 1 and Galbraith 2, Estimated Conversion Cost - $1,337,927.31
iii. Baldwin 1 and Baldwin 2, Estimated Conversion Cost - $2,237,680
iv. John 1 and John 2, Estimated Conversion Cost - $2,108,721.46

v. Highland 3, Estimated Conversion Cost - $1,881,232.11
vi. Highland 1, Estimated Conversion Cost - $544,414.81
vii. Highland 2, Estimated Conversion Cost - $339,915.61

Deerhurst, Galbraith, Baldwin, John and Highland substations are suggested for decommissioning.

This concludes the list of feeder recommendations in the 4.16 kV and the 8.32 kV voltage level for conversion. By completing the conversion process, Horizon Utilities would successfully transfer all the customers currently in the Hamilton and St. Catharine service area from the 4.16 kV or 8.32 kV voltage levels to the 13.8 kV and 27.6 kV voltage levels, respectively.

3. Conversion Plan – Design Criteria and Methodology

The 4.16 kV and 8.32 kV voltage level conversion plan entails a list of feeders in the order of recommendation of conversion to the 13.8 kV and 27.6 kV voltage level. The feeder order of recommendation is based on the drivers that have been identified as design criteria to provide the most suitable justification for undertaking the conversion projects. These drivers are utilized in various ways in the different stages of development to derive a detailed scoring methodology to analyze each of these feeders. Based on this scoring methodology, the feeders are evaluated in comparison to each other leading to a final feeder ranking. The year of conversion is derived based on the ranking, suitable time of asset renewal and an anticipated level of capital expenditure available at the time of conversion. The methodology of the conversion plan is broken down into the Feeder Ranking, Substation Condition Scoring, Cost Analysis and Recommendation Feasibility Analysis procedures. The criteria are used as inputs to each of these design procedures to provide adequate results to derive the outputs used eventually to come up with the final plan.

3.1 Criteria

Following are each of the criteria and their contributions in the different stages of the design methodology procedures:

Distribution Asset Age

Upgrading the aging distribution assets is the major driver behind the conversion projects in Horizon Utilities. The distribution assets in the 4.16 kV and 8.32 kV voltage level service areas are nearing their end of life and in some cases running at capacity. So, it is economically more beneficial to replace the assets to meet the higher voltage standards and avoid the risk associated to unplanned outages due to failure. Based on the demographics of the distribution assets found of the Geographic Information System (GIS), not adopting a proactive replacement strategy would cause major unplanned outages, high levels of capital expenditures and higher operating and maintenance costs. The conversion plan accommodates the proactive replacement of these aging assets. The assets considered are transformers, poles, conductors and cables. Under the Substation Ranking procedure, the average age and probabilities of failure of these assets are utilized to come up with a weighted score that has been created to evaluate each of the substation's condition relative against each other. This was used to derive a substation conversion rank and eventually utilized in the final conversion plan.

Substation Asset Condition

The major assets in a distribution substation are power transformer, Bus Bar, Circuit Breakers and Feeder Cables. The substation assets are managed through extensive maintenance programs and analysis of the results are used to predict failure modes in small time frames. Capital Investments on substation assets are difficult to predict for longer periods of time and is suggested that the assets requiring immediate attention be repaired when such failure modes are observed. For the purpose of capturing the substation condition to justify the year of decommissioning, the substations have been individually visited with expert substation crews to document the overall facility condition, safety and environmental concerns, past records of major failure and recent or impending major investments. These factors are all integrated as best suitable in the final plan in the form a high level Substation Condition Scorecards. It is suggested that these scorecards are referred to when the substations are being decommissioned. Refer to Section 6 to view these Substation Scorecards.

Feeder dependency and reliability

Horizon Utilities distribution feeders are operated with a detailed contingency plan allowing a sufficient amount of redundancy and capability of load transfers in case of feeder failure. This strategy to enable higher reliability indices and greater customer satisfaction has been considered thoroughly to derive the system conversion plan. Before a feeder has been recommended for conversion, the feeder for which it is a backup for has been checked to see whether it has adequate transfer capabilities or not. This has eventually in some cases lead to better condition feeders to be recommended for conversion before another feeder of worse shape. It has also created situations where it has been recommended that either two feeders are converted together or that a tie-switch is installed to the backup feeder while one feeder is being converted. This has been the major consideration in the Feeder Ranking procedure conducted on each feeder and eventually used to create the final conversion plan.

Customer Impact

The number of customers connected into each feeder has been considered in the conversion plan. The customer score has been created weighting the commercial customers higher than the residential customers. This has been accommodated in the final conversion plan in the Feeder Ranking procedure. In situations where two feeders are compared having distribution similar distribution asset condition, the feeder with higher customer score has ranked higher in terms of conversion. The reasoning behind this is justified because of the fact that when an outage occurs to a feeder supplying a higher number of customers, the reliability indices of the company suffers more.

Source Availability

Availability of a 13.8 kV or 27.6 kV voltage source in the area of conversion has been considered to derive the final conversion plan. This criterion utilized GIS to provide its input to the Recommendation Feasibility Analysis procedure to check whether in the suggested time of conversion, a higher voltage source in available in the area to eliminate the feeder. This plays a crucial role in justifying the design criteria of the conversion project and avoids cases of expensive overbuilding required to bring the higher voltage source to the feeder suggested for conversion. This check has been conducted for every feeder based on the order of conversion recommendation.

Cost of Conversion

The cost of conversion is another major driver in the conversion process as well as the final suggested time of conversion of the feeders. The conversion costs were evaluated based on a like for like replacement of major distribution assets. An innovative automated cost estimated tool was created to evaluate the conversion costs for each feeder. The tool can be used for estimating feeder conversion cost, anticipated capital expenditure levels for each substation and costs of deferring conversion. Based on the feeder ranks, conversion cost estimate and anticipated expenditure levels in the future the final suggested year of conversion was derived.

3.2 Methodology

As mentioned earlier, the Conversion Plan is developed based on the Feeder Ranking, Substation Condition Score, Cost Analysis and Recommendation Feasibility Analysis procedures. The following is a detailed explanation of these procedures and how they were each utilized to derive the final conversion plan and feeder conversion recommendations.

Feeder Ranking

The final conversion plan is based on the results of the overall feeder ranking procedure. In this procedure, initially, the GIS information on major distribution assets connected to each feeder has been captured together in one database to provide adequate scoring capabilities. For each feeder the data captured is for distribution transformers, poles, conductors and cables. For each of these assets, the data collected are Asset ID, Probability of Failure and Replacement Costs. Based on the average probability of failure and adequate weighting for each asset class based on their costs and impact of failure, a final weighted probability of failure of assets has been calculated for each substation. This resulted to the overall substation probability of failures and decommissioning ranks. Based on these decommissioning rankings, all the feeders from each substation are compared with each other to derive the feeder conversion rankings. Finally, these feeder rankings were used integrally in the final system conversion plan detailed in Section 2.

Substation Condition Scoring

The substations were inspected individually with expert members of the substation crew to develop a substation condition scorecard. The scorecard has been developed to document the overall facility condition, safety and environmental concerns, past records of major failure and recent or impending major investments. It also captures the feeder backup capabilities and the most importantly any special considerations required during the substation decommissioning process. Considering each of these factors, a substation condition score has been produced to rate the substations relative to each other. These factors have also been considered to cross-verify the distribution feeder rankings to derive the eventual feeder conversion rank and suggested conversion year.

Note: Refer to Section 5 for the Substation Condition Scorecards. This information is useful during the decommissioning of the station.

Cost Analysis

An innovative and automated Cost Analysis tool has been developed to calculate the feeder conversion costs. All the substation and distribution Asset ID, Probability of Failure and Conversion Cost have been captured in one database. Then the analysis tool has been developed to use all this data to calculate the total cost of feeder conversion, project Capital Expenditure levels for each substation and the cost of deferring conversion for each substation. The Cost Analysis tool is completely dynamic and if in the future if this plan is re-evaluated, this tool can be used again with updated information available at that time to re-calculate the Conversion Costs. The results of the tool have been cross-verified with project estimates conducted by the Engineering Design group to check its accuracy. It has been observed to be accurate and comparable to the estimates, validating its methodology and approach of the calculation procedure. The results from the Cost Analysis procedure has been compared against expected expenditure levels in the future to develop the conversion year recommendations.

This tool has also been used to generate a graphical comparison between the capital expenditure levels between planned and unplanned conversion levels. The graph indicates that the conversion plan recommended would allow us to invest on a relatively constant level in the next 20 years making it affordable and justifiable. This would also ensure that we avoid undue reliability risk by retaining assets which are near or over their end of life and can fail unpredictably. Refer to Figure 5 for a graphical representation of this comparison.

Recommendation Feasibility Analysis

The feeders recommended from the Feeder Ranking procedure have been evaluated through the Recommendation Feasibility Analysis procedure. As part of the procedure, all the feeders from each substation have been checked for backup and source availability. An overall geographical analysis has been conducted on the GIS to develop a high-level conversion design model. This design model checks whether the feeders being converted leaves adequate backup capabilities for it's after during and after conversion. This is essential to maintain the redundancy and load transfer capabilities in feeders in case of failures. This also aids towards maintaining high reliability indices for Horizon Utilities. The check has resulted in suggestions of installing a tie-switch to provide backups for certain feeders during a project and in some cases suggestions of converting two feeders together to prevent expensive additional investment in installing a tie-switch. This procedure also entailed checking whether a 13.8 kV or 27.6 kV voltage source is available to extend to eliminate a certain feeder being converted. This is essential to prevent unnecessary investments to bring a 13.8 kV or 27.6 kV voltage source to the project location. The result of this procedure determined the final feeder ranking that has been detailed in Section 2.

A final verification check has been conducted to verify whether the feeder conversion year recommendations are making sure that the distribution assets are being replaced within their defined end of life. The end of life cut-off is set to 50 years for transformers and 60 years for poles. This cut-off age is not very conservative because of the fact that many of our assets have exceeded that age without major failures and also for the fact that if the end of lives are set to lower values it would imply that our capital expenditure levels are exceptionally high. The results of this procedure indicated that only 8 of the 170 feeders would have average transformer and pole lives exceed slightly over this cut-off age. These results adequately verified the validity of the recommendations. It also proved the recommendations were congruent with the intentions of the conversion plan to allocate resources in the different areas of the grid in a fashion that we would be able to eliminate risks in retaining old assets in our distribution system and have high unanticipated capital expenditure levels at some point in the future.

4. Conversion Maps – Horizon Service Area

The following are the GIS Maps showing the areas served by the 4.16 kV and 8.32 kV voltage levels in the Horizon Utilities Corporation Service area.

4.1 Service area – Hamilton

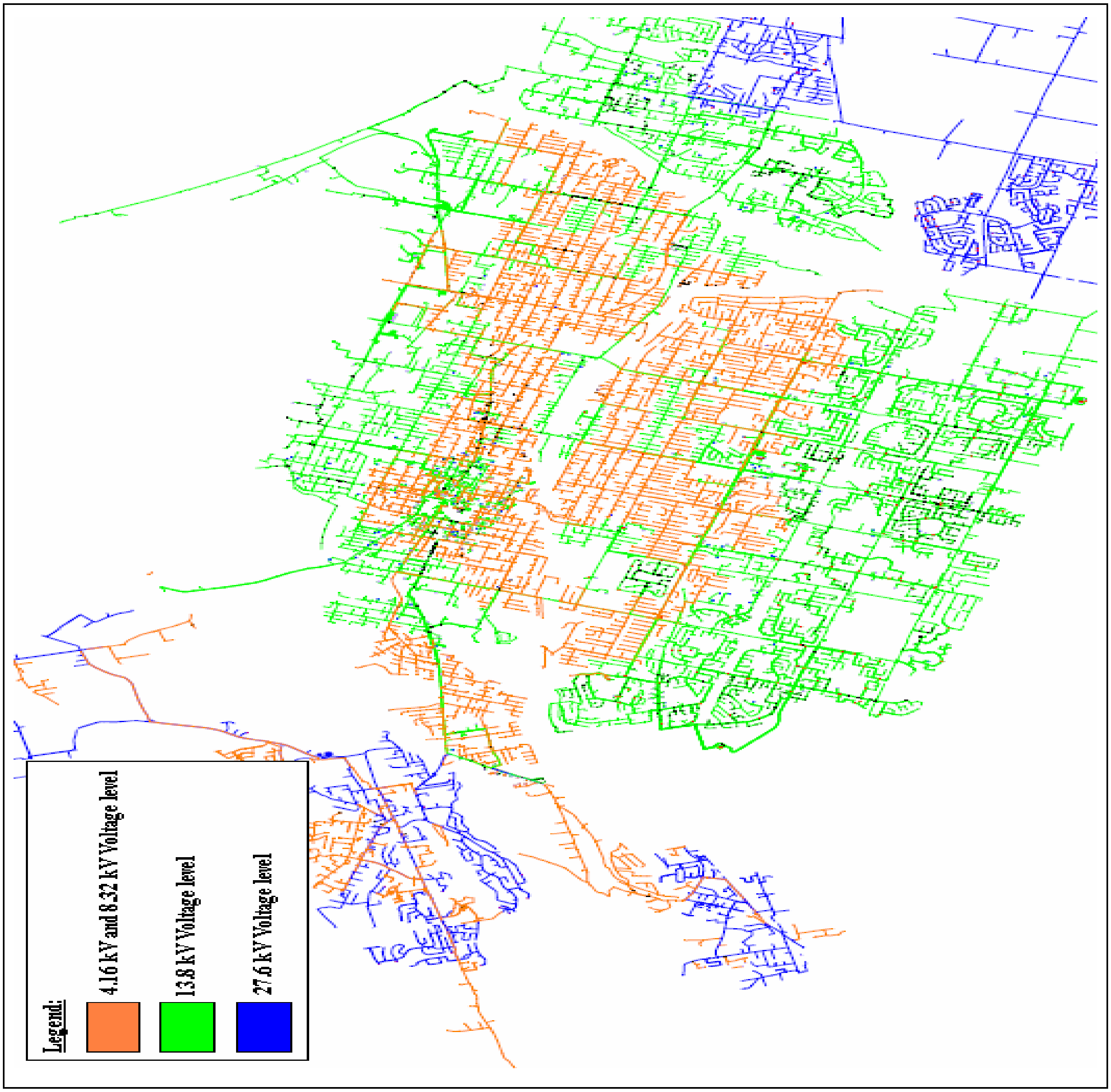

Figure 1

4.2 Service area – St. Catharines

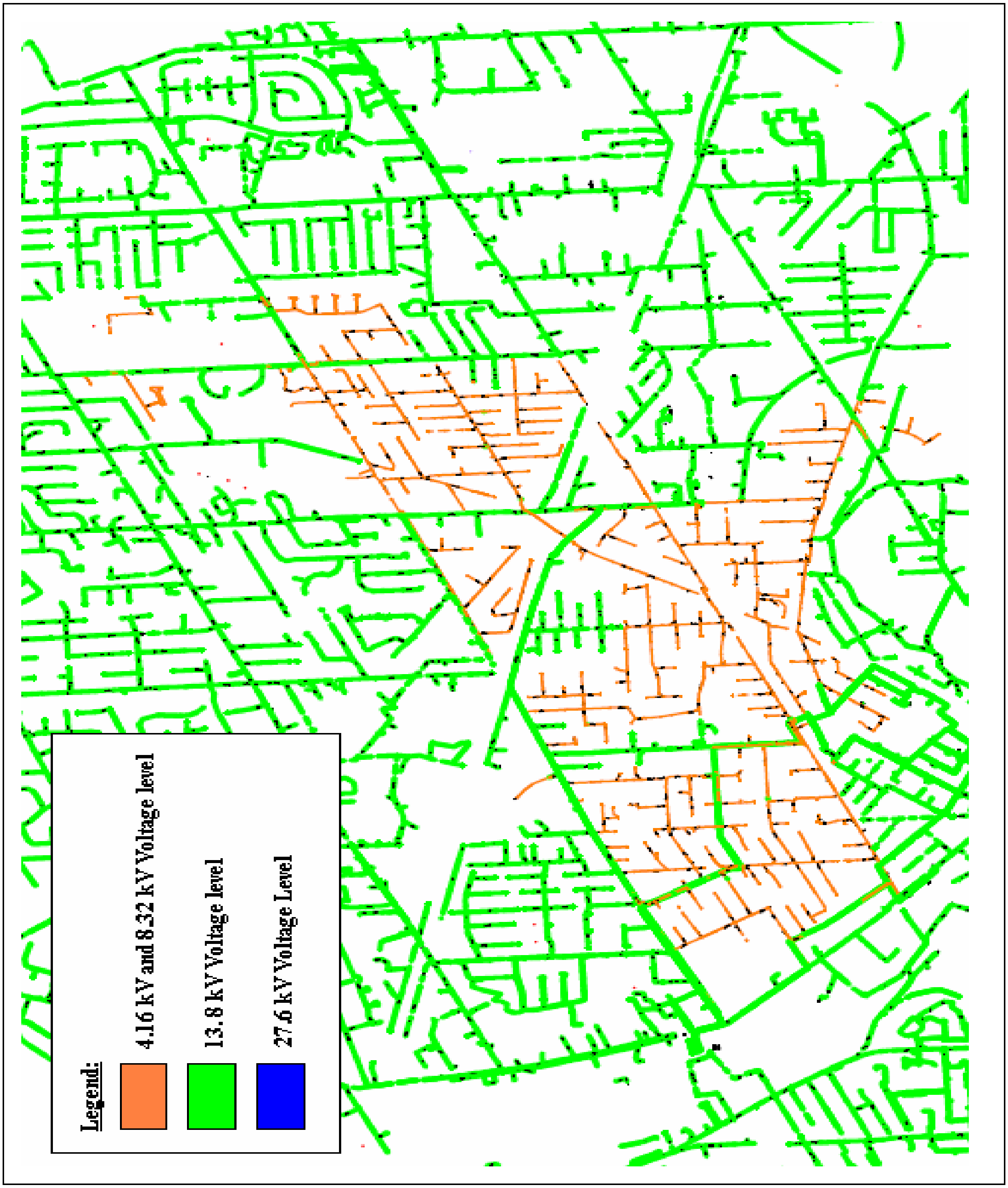

Figure 2

4.3 Conversion Ranking Map – Hamilton

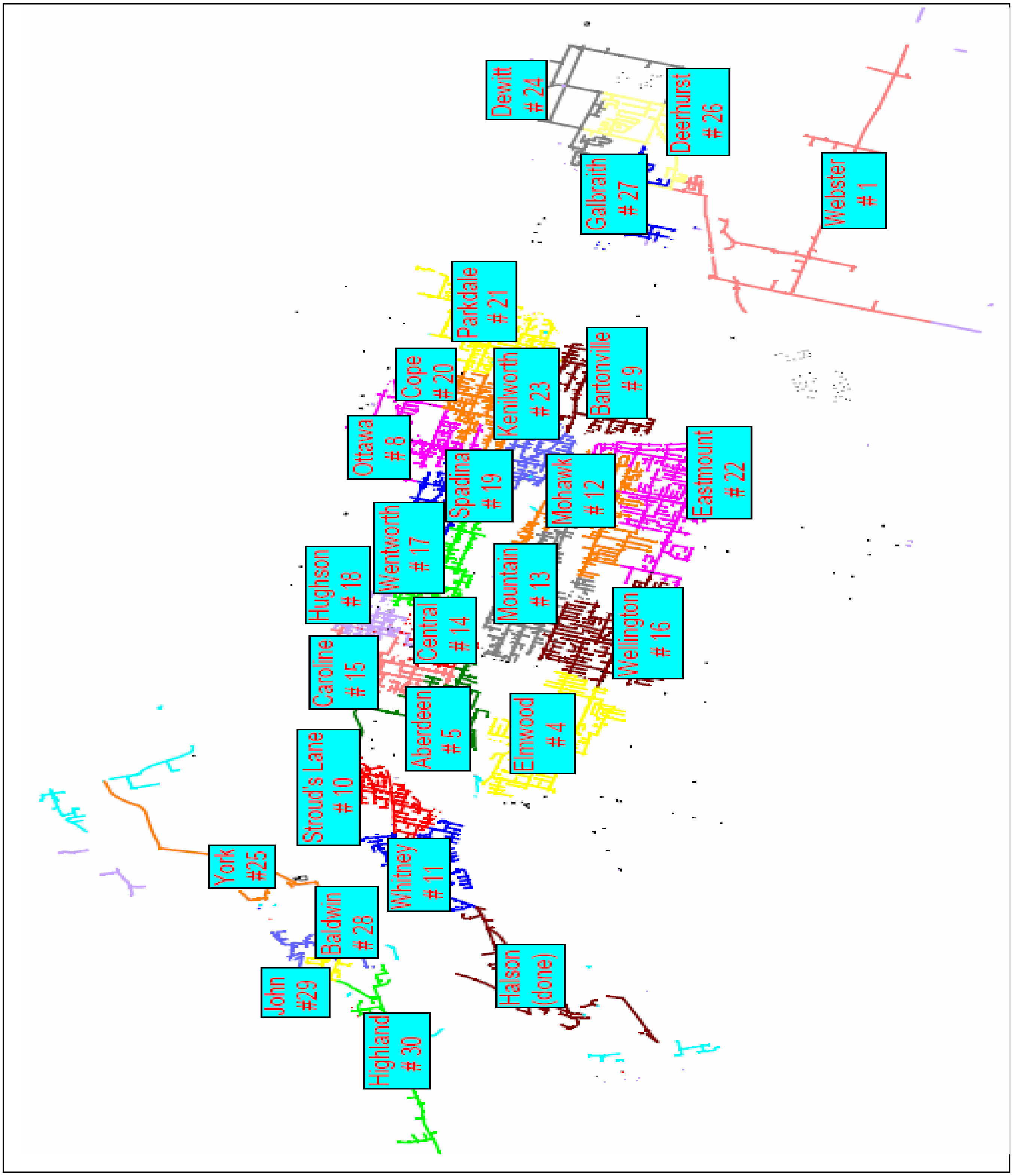

Figure 3

4.4 Conversion Ranking Map – St. Catharines

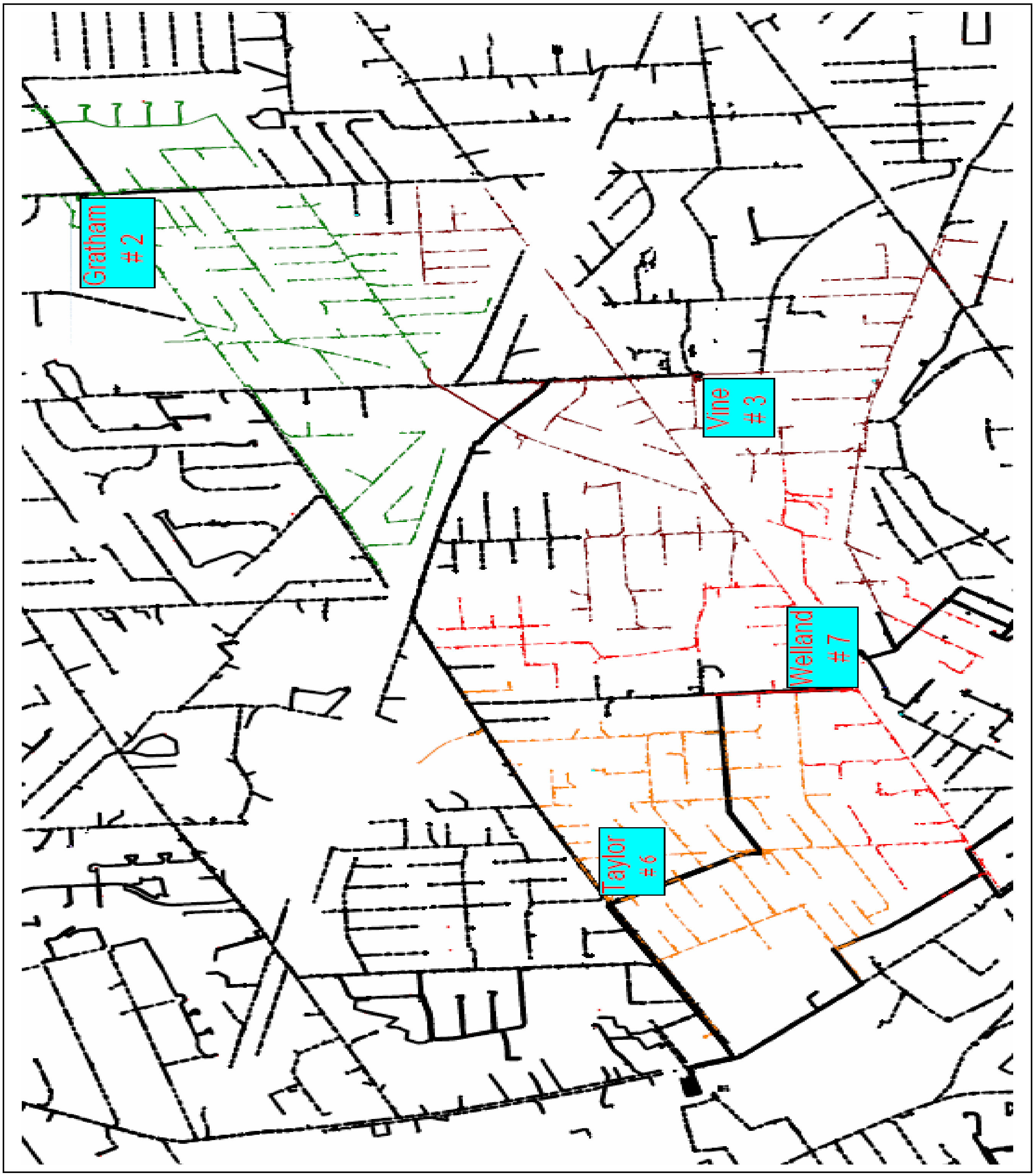

Figure 4

5. Expected Expenditure levels of Conversion – Year 2007 - 2026

The following figure is a snapshot of the capital expenditure levels of conversion between the years 2007 and 2026. In blue is the capital expenditure level of unplanned conversion and in maroon is the suggested capital expenditure level.

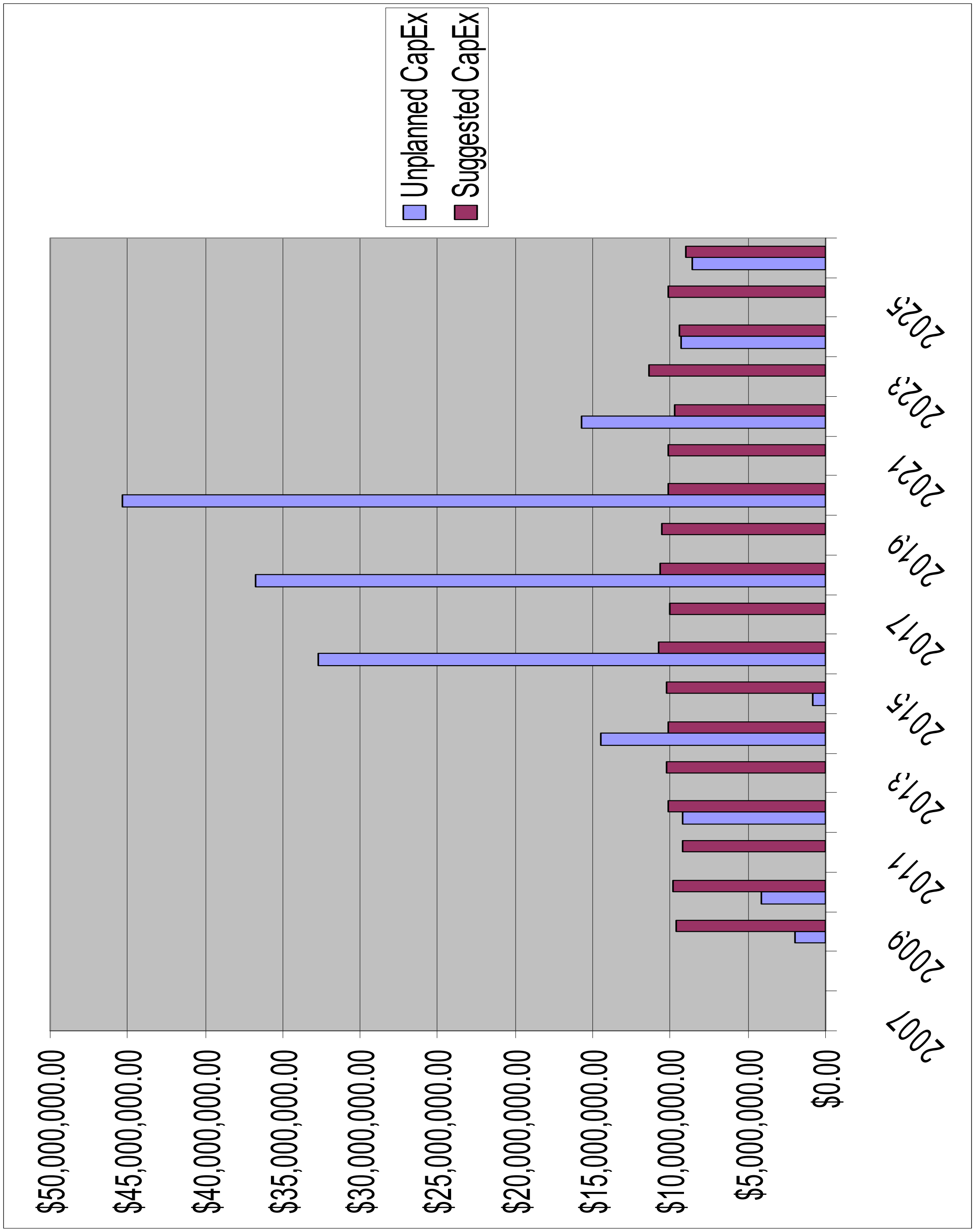

Figure 5

6. Substation Condition Reports

The following are the substation condition reports for the 30 substations in the Horizon Utilities Corporation's service area. It is suggested that these scorecards are referred to during the time of station decommissioning to be aware of any safety, environmental or special considerations that need to be attended to during the decommissioning procedure.

Aberdeen

Year Built: 1969

Address: 416 ABERDEEN AVENUE, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8/10

Condition Assessment / Comments

The facility has slite roof which is harder and more expensive to maintain. It also has a blast wall installed to protect the neighbors' in case of transformer explosion.

Then breakers are in pretty good shape. They have been overhauled recently. The parts for these kinds of circuit breakers are hard to find in case of required replacements. There are a couple of spare circuit breakers in this substation. The batteries for the station service transformer have been changed recently.

The transformers are in really good condition. There had been hot spots reported in them in a past thermography test result. These issues had been dealt with from them. They are overall in pretty good condition.

There are access issues to this substation in winter because the entrance is through the back and the Hamilton city is responsible for clearing the snow in the backyard, which is not conducted regularly making maintenance during winter troublesome as well as risky.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
AB-1	1775	AB-2	
AB-2	1371	CA-3	AB-1, AB-5
AB-3	1486	AB-5	
AB-4	1646	CA-5	
AB-5	1820	AB-6	

Conversion Rank: 4
Suggested Decommissioning Year: 2012

Baldwin

Year Built: UNKNOWN

Address: UNKNOWN

Facility: OUTDOOR S/S

Facility Condition Score: 7.5 / 10

Condition Assessment / Comments

Standard outdoor station build standard. Past corrective maintenance has entailed occasional recloser switching issues caused by delayed hydraulic reaction times for switch closing. This is mainly caused by unbalanced oil pressure which has caused issued regarding variable resetting times.

Rusting on the support structure may be an issue to look into in the future. This location has seen fewer effects of theft and vandalism primarily due to the secluded nature of the property and unexposed boundaries on 3 sides.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
BD-1	2,485	BD-2	JN-1, JN-2
BD-2	940	YK-2	BD-1

Conversion Rank: 27

Suggested Decommissioning Year: 2036

Bartonville

Year Built: 1952

Address: 2355 KING STREET EAST, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8 / 10

Condition Assessment / Comments

The facility has slite roof which is harder and more expensive to maintain.

There is 1 transformer in the station and has been very reliable in the past. This substation houses 1 spare transformer. The transformer is relatively new (built – 1985) and is in very good condition. There is no spill containment in the transformer base and is a possible environmental issue to be noticed.

The Oil Circuit Breakers (OCB) are free breathers and absorb moisture from the atmosphere. This makes them more expensive to maintain. They are in a 3 year maintenance cycle and the ones in this station will be replaced by the end of the year.

There are three 13 kV sources coming into the station which provides it with greater redundancy and reduces the amount of risk associated to the station. 13 kV and 4 kV cables are being redone so that in case of transformer failure, the load can be easily transferred.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
BA-1	1305	BA-4, PA-5	BA-2
BA-2	928	BA-1	KE-5
BA-3	559	BA-4, BA-7	
BA-4	1743		BA-1, BA-3, KE-6
BA-7	971		BA-3

Conversion Rank: 8

Suggested Conversion Year: 2016

Caroline

Year Built: 1955

Address: 117 MARKET STREET,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 6.5 / 10

Condition Assessment / Comments

Both the transformers are in pretty bad shape. Pyro wires have blown in the past and have been taken off completely. The fans are not working and the gauges are broken. Heavy corrosion is visible on the conduits, studs and fittings are broken. There are signs of oil-leaks and are weeping down the gaskets. The relays mounted on the transformers are extremely old. Overall the transformers are extremely rusty with signs of oil-leak on the body and ground. Maintenance work is also difficult because of condition.

Air Circuit Breakers in this Substation are in extremely good condition and are suggested to be stored as replacements for other stations having similar equipment. This is due to their reliability and efficiency in maintenance procedures.

The electrical panel is relatively new in this substation.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
CA-3	1442	CA-5	AB-2
CA-4	2216	HU-6	HU-4, HU-5
CA-5	1232	CE-2	AB-4, CA-3
CA-6	1233	CA-8	
CA-7 / HU-12	362		
CA-8	374		CA-6

Conversion Rank: 14

Suggested Decommissioning Year: 2018

Central

Year Built: 1950

Address: 193 JOHN STREET SOUTH, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8 / 10

Condition Assessment / Comments

Transformers are relatively newer (1980s). One transformer blew up about 12 years ago and was replaced and this station hasn't faced any transformer related issues since then.

Breakers in this station have faced operating issues and might require maintenance in the near future. The metal clad is old with inefficient creaking and unimpressive mechanical fit and finish. This causes inefficient maintenance operations.

The electrical panels have been replaced about 10 years ago. New batteries have installed recently.

There is a manhole going from the basement of the station to the street side. An added consideration if property sold including the building.

The station overall is very clean. The station is in much better shape and condition with new equipment than other stations.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
CE-1	671		
CE-2	1100	CE-8	CA-5
CE-3	1056	CE-10, CE-8	
CE-4	1431	CE-11	CE-5
CE-5	390	CE-4	
CE-6	225		
CE-8	834		CE-2, CE-3
CE-9	137		
CE-10	1458		CE-3, MT-10
CE-11	1102	CE-4	

Conversion Rank: 13

Suggested Decommissioning Year: 2017

Cope

Year Built: 1965

Address: 1430 BARTON STREET EAST, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8.5 / 10

Condition Assessment / Comments

The Transformers and Air Circuit Breakers (ACB) in this station have been very reliable in the past. No instances of major maintenance work have been done. One of the transformers has been recognized as noisy but has sound functional integrity. The transformers in the transformer bay are close to each other and do not abide the present transformer positioning standards followed while building new substations.

This station has a Fiber-Optic junction point and is a consideration while Conversion as we have to provide them an early notification to relocate it.

Overall, the facility is in very good shape with no major issues to be aware of.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
CP-1	997	CP-9, PA-5	KE-2
CP-2	1802	CP-8	
CP-3	999	PA-9	
CP-4	651	PA-3	CP-7
CP-5	1938	CP-6, OT-5	
CP-6	1046		CP-5
CP-7	1543	CP-4	OT-4
CP-8	673		CP-2
CP-9	1807		CP-1

Conversion Rank: 20

Suggested Decommissioning Year: 2022

Deerhurst

Year Built: UNKNOWN

Address: 357 Hwy # 8

Facility: OUTDOOR S/S

Facility Condition Score: 9 / 10

Condition Assessment / Comments

This outdoor property is leased. The station is functionally very sound with no major issues experienced in the past. The transformer is in very good condition

The current transformers are not working properly and are under investigation.

The single phase reclosers are suggested to be replaced by three phase reclosers to increase reliability. Overall, there is no safety, reliability or environmental issues in this station. This station has been identified as one of our best substations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
DH-1	2766	DH-2, DW-2, DW-3	
DH-2	1268	GA-2	DH-1, DW-1
DH-3	3343	GA-2	WB-2

Conversion Rank: 26

Suggested Decommissioning Year: 2026

Dewitt

Year Built: UNKNOWN

Address: DEWITT ROAD, STONEY CREEK

Facility: OUTDOOR S/S

Facility Condition Score: 8 / 10

Condition Assessment / Comments

The transformers have automatic tap changers and are hard to maintain. These transformers are in pretty good condition and have performed reliably in the past. The equipment are mounted on the old structure going from over the transformer and in case of transformer replacement, this part of the structure has to be disassembled.

This station also has single phase reclosers which are suggested to be replaced by three phase reclosers to increase reliability of the station and have minimal impact on three phase commercial customers in the case of failure. There is a dysfunctional insulator caused by an electrical flash over.

This is a lightly loaded station and poses very little cause of concern. The station is exposed to salt and debris because of the location of the station beside the QEW. There is no sign of theft or vandalism in this station as seen by some other outdoor substations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
DW-1	2,299	DH-2, DW-2, DW-3	DW-3
DW-2	144	DW-3	DH-1, DW-1, DW-3
DW-3	1,440	DW-1, DW-2	DH-1, DW-1, DW-2

Conversion Rank: 24

Suggested Decommissioning Year: 2025

Eastmount

Year Built: 1959

Address: 856 MOHAWK ROAD EAST,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 7 / 10

Condition Assessment / Comments

Window operators don't work causing lack of ventilation in the premises.

The Air Circuit Breakers have experienced reeking problems causing maintenance issues.

A lot of oil has leaked from the transformers and is an issue to look further into in the future. Environmental assessments and heavy clean-up is required as part of the Conversion procedure.

Fiber-wired junction point exists in the building and they should be notified well ahead of Conversion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
EA-1	1035	MK-1	MK-11
EA-2	1378	EA-10	MK-2
EA-3	1771		EA-8, MK-10
EA-4	680	EA-6, EA-11	
EA-6	1568		EA-4
EA-7	1192	EA-9	
EA-8	1819	EA-3	
EA-9	1394		EA-7, MK-6
EA-10	1250		EA-2
EA-11	1381		EA-4

Conversion Rank: 22

Suggested Decommissioning Year: 2024

Elmwood

Year Built: 1958

Address: 218 WEST 19TH STREET,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8.5 / 10

Condition Assessment / Comments

This station has a blast wall installed to protect neighbors in case of a transformer explosion.

Air Circuit Breakers are in good shape and have been overhauled last year.

There is a fiber-wired junction point inside this station. This is a special consideration during Conversion as they would need early notification to relocate it.

The transformers are leaky and have been identified for maintenance next year. Overall, the transformers are in pretty solid condition with no known history of failure or defect.

The batteries are in good shape. The station service transformers, like all other stations, have no spill-containment and in a possible hazard to be looked into.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
EL-2	1087	EL-8	
EL-3	1038	EL-7	
EL-4	1331	WL-6	EL-7
EL-5	1543	EL-10	
EL-7	1219	EL-4	EL-3
EL-8	1387	EL-9	EL-2
EL-9	908	WL-10	EL-8
EL-10	374		EL-5

Conversion Rank: 4

Suggested Decommissioning Year: 2010

Galbraith

Year Built: 1959

Address: 16 GALBRAITH DRIVE,
STONEY CREEK

Facility: OUTDOOR S/S

Facility Condition Score: 8 / 10

Condition Assessment / Comments

This station Oil Circuit Breakers (OCB) housed inside metal enclosures. They are in relatively good shape and functionally sound. There is minimal maintenance required in the substation.

The transformers have performed reliably in the past and are in pretty good condition.

There are extensive effects of copper theft and vandalism in the station based on its location and neighborhood.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
GA-1	156	GA-2	GA-2
GA-2	407	GA-1	DH-2, DH-3, GA-1, GA-3, WB-2
GA-3	2	GA-2	

Conversion Rank: 27

Suggested Decommissioning Year: 2026

Highland

Year Built: 1977

Address: 259 GOVERNORS ROAD, DUNDAS

Facility: INDOOR S/S

Facility Condition Score: 6 / 10

Condition Assessment / Comments

Facility is shared with Hamilton Waterworks housing a water pumping station. This will require special consideration during the whole decommission procedure as we don't have access to there part of the facility and holds parts of our equipment. The water pump is fed off our feeder and will need to be recognized as part of the upgrade.

New batteries for Circuit Breakers will be installed soon. Unique auto-recloser feature installed with circuit breakers.

This substation has experienced signs of extreme vandalism and theft in the past in the form of shots from air soft guns from the neighborhood and fenced being cut off from the property. There is also animal intervention in the property. As the property is below ground level, during winter large amounts of snow piles up around the transformer bank which makes it potentially hazardous. These environmental aspects make maintenance procedures extremely difficult and major safety threats ensue.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
HI-1	743		
HI-2	670	JN-1	HI-1, HI-3
HI-3	1133	HI-2	

Conversion Rank: 30

Suggested Decommissioning Year: 2026

Hughson

Year Built: 1926

Address: 48 HUGHSON STREET NORTH,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 7 / 10

Condition Assessment / Comments

Transformer T-2 is not very reliable. Vibro-Acoustic testing on the transformer has indicated loose winding in the transformer. All four transformers are housed inside enclosed transformer bay which make maintenance work difficult and also hazardous in case transformer catches fire. Risk can be reduced if one transformer is taken-off as this is station is lightly loaded. The oil will also spill into the basement causing massive safety issues.

Plastic Pellet switches inside the air circuit breakers (ACB) have been found broken and has required replacement several times in the past. There have been no other issues experienced regarding the ACBs and are generally very reliable.

The SCADA interface cabinet for all stations is housed in this station facility and is extremely sensitive to any kind of failure and will cause major disruption to our system operation.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
HU-2	600		
HU-4	1048	CA-4	
HU-5	1287	CA-4	
HU-6	1600	HU-7, HU-11	
HU-7	1216	HU-11	HU-6
HU-8	155		
HU-9	208		
HU-10	519		
HU-11	1490	WT-10	HU-6, HU-7

Conversion Rank: 18

Suggested Decommissioning Year: 2020

John

Year Built: 1985

Address: 150 HATT STREET,
DUNDAS

Facility: OUTDOOR S/S

Facility Condition Score: 6.5 / 10

Condition Assessment / Comments

This substation has the same outdoor station structure as Baldwin S/S and York S/S.

Facility houses 1 spare transformer. Premise has been affected by extremely vandalism in the past in the form of stolen fences and stones being hurled at the equipment.

New switches and fuses have been installed in the near past.

Equipment overall are rusty and damp from leaks. These are mainly caused by environmental exposure and location near lake. On the contrary, transformer is in pretty good shape with no visible leaks.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
JN-1	1982	JN-2, BD-1	HI-2
JN-2	383	BD-2	JN-1

Conversion Rank: 29

Suggested Decommissioning Year: 2026

Kenilworth

Year Built: 1960

Address: 96 KENILWORTH AVENUE SOUTH,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8.5 / 10

Condition Assessment / Comments

This indoor facility has a slite roof which is harder and more expensive to maintain.

Asbestos is found on the wall and has been patched to avoid exposure.

There is no spill containment in the base of the transformers and could be a possible environmental issue. The station is heavily loaded and has experienced high peaks during the summer months. The transformers are very close to the building which makes them harder to do maintenance work on them. However, they have been very reliable in the past with so major issues experienced. There are no safety issues based on exposure to the surroundings.

The Air Circuit Breakers (ACB) have been very reliable as usual and are also easily maintained. The electrical wiring for the station has been done in the last 10 years.

There is a manhole leading to the roadside in the basement and is an issue to be recognized in case the property is considered for resale.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
KE-1	1813	KE-6, SP-3, OT-6	KE-3, KE-4
KE-2	937	CP-1	
KE-3	1768	KE-1, KE-5	
KE-4	1579	KE-1, KE-5	
KE-5	600	BA-2	KE-3, KE-4
KE-6	1510	BA-4	KE-1

Conversion Rank: 23

Suggested Decommissioning Year: 2024

Mohawk

Year Built: 1953

Address: 709 UPPER GAGE,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 7 / 10

Condition Assessment / Comments

New feeder wraps and duct seals have been installed on the transformers. Station service equipment has been rewired in the near past.

This premise houses 1 spare air circuit breaker and oil circuit breaker each. New batteries for circuit breakers have been installed recently.

The property is pretty big and will bring in a lot of revenue if sold off after Conversion. The substation is in pretty good overall condition will minor spill from conductors in the basement.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
MK-1	1831	MK-9	MK-9, EA-1
MK-2	1185	EA-2, MK-5, MK-6, MT-6	
MK-3	1656		MT-2, MT-3
MK-5	492		MK-2
MK-6	1118	EA-9	MK-2
MK-9	1125	MK-1, MT-3	MK-1
MK-10	2041	EA-3	
MK-11	2172	EA-1	

Conversion Rank: 12

Suggested Decommissioning Year: 2016

Mountain

Year Built: 1965

Address: 510 UPPER WENTWORTH, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 6 / 10

Condition Assessment / Comments

The facility has slite roof which is harder and more expensive to maintain.

Bus work was redone on the 13 kV side last 10 years but nothing has been done on the 4 kV side.

Station service electrical work has been done recently. Breaker panels have been redone. One spare air circuit breaker and oil circuit breaker is housed in this station. Batteries for the breakers have been recently installed.

Directional blocking switches have been kept open because of lack of investigation and reason as to why the station goes down when they are closed.

There are 3 power transformers in this station among which 2 are newer than the other. 2 spare transformers are also housed in the transformer bay. The older one has new feeder wraps.

The physical condition of the walls is very poor with signs asbestos. There is a lot of oil and water leak in the basement wall from conductors.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
MT-2	1342	MT-3, MK-3	
MT-3	1537	MK-3	MT-2, MK-9
MT-4	1757	MT-9, MT-10, MT-11	MT-5
MT-5	1399	MT-4, MT-6, MT-10	WL-9
MT-6	1547		MK-2, MT-5, MT-9, WL-2, WL-4
MT-9	1695	MT-6	MT-4
MT-10	1611	CE-10	MT-5, MT-11
MT-11		MT-10	MT-4

Conversion Rank: 13

Suggested Decommissioning Year: 2016

Ottawa

Year Built: 1967

Address: 64 DALKEITH STREET,
HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8.5 / 10

Condition Assessment / Comments

This station has a standard Air Circuit Breaker setup with relatively new metal-clad and equipments.

This station has been extremely reliable with no major failures. Three power-transformers are housed in the bay which were installed in the 1960s and are still in pretty good condition. There is also a slot open to house another power-transformer in the bay.

There have been no effects of theft or vandalism. The substation is very clean and physically in very sound condition.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
OT-1	595	OT-2	OT-8
OT-2	1087		OT-1
OT-3	1348	OT-4	KE-1, SP-1
OT-4	1709	CP-7	OT-3
OT-5	1102	OT-6	CP-5
OT-6	148		OT-5
OT-7	1267	SP-7	
OT-8	795	OT-1	

Conversion Rank: 8

Suggested Decommissioning Year: 2013

Parkdale

Year Built: 1924

Address: 300 PARKDALE AVENUE NORTH, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 7.5 / 10

Condition Assessment / Comments

The transformers are in the parking lot and are a potential safety issue.

There is a combination of Air Circuit Breakers and Oil Circuit Breakers in this substation. The metal clad is relatively new. The electrical panels are old and might require attention in the future.

There are multiple 13 kV sources in this substation which improves the redundancy and reduces the risk associated to this substation. Overall, the station is pretty reliable and functionally stable.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
PA-3	858		CP-4
PA-4	1497	PA-7	
PA-5	1660	PA-10	BA-1, CP-1, PA-1
PA-6	448	PA-8	
PA-7	1382	PA-8	PA-4
PA-8	1501		PA-6, PA-7, PA-9, PA-11
PA-9	619	PA-8	CP-3
PA-10	1352	PA-5	
PA-11	641	PA-8	

Conversion Rank: 21

Suggested Decommissioning Year: 2023

Spadina

Year Built: 1930

Address: 994 KING STREET EAST, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 7.5 / 10

Condition Assessment / Comments

A transformer had failed in the past exploding through glass windows. The glass windows on the transformer bay side has been shut will steel plates ever since. As precaution, a blast wall will be built soon to provide protective shield to protect the neighbors in case another explosion occurs. The transformer has not been replaced and the load was transferred over.

The bus cover and metal-clad was replaced around 20 years ago. New breaker batteries were installed in 2004.

The station has been generally very reliable with no recollection of major cable faults or breaker failure.

This station is used as a training facility for the underground splicing crew. There is a roadside man-hole from the basement of this substation. These are added considerations during Conversion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
SP-1	1516	SP-5	OT-3
SP-2	1709	WT-9	SP-5
SP-3	1418	SP-4, SP-10	WT-10
SP-4	831	SP-6	SP-3
SP-5	1786	SP-1, SP-2	SP-9
SP-6	1986		KE-1, SP-4
SP-7	765		OT-7
SP-10	667		SP-3

Conversion Rank: 19

Suggested Decommissioning Year: 2021

Stroud's Lane

Year Built: 1938

Address: 1225 MAIN STREET EAST,
HAMILTON

Street Names: MAIN & STROUD'S LANE

Facility: INDOOR S/S

Facility Condition Score: 7.5 / 10

Condition Assessment / Comments

No maintenance on the bus work has been conducted in the past. The low loading on the station dictates the good condition of the bus work.

Premise has a consistent foul odor and might be caused by a possible gas leak. This requires further investigation.

Fiber-wired junction point inside the station and requires consideration when the station will be decommissioned. Early relocation notification should be given to them while engineering is working on the Conversion.

There are 2 transformers in the substation and are in fairly good condition. The station is in good overall condition.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
ST-2	1325	ST-7	
ST-3	1364	ST-4	
ST-4	1112	WH-2	ST-3, WH-1
ST-6	1516	ST-7	AB-5
ST-7	1273		ST-2, ST-6

Conversion Rank: 10

Suggested Decommissioning Year: 2014

Webster

Year Built: UNKNOWN

Address: 86 WEBSTER ROAD, STONEY CREEK

Facility: OUTDOOR S/S

Facility Condition Score: 6 / 10

Condition Assessment / Comments

This outdoor station has been identified as high risk condition.

The transformers are among the oldest in our system (e.g. built – 1952). The Oil Analysis results have identified the transformers to have been exposed to extremely high heat and have caused deterioration in the paper insulation. This might cause transformer to fail and cause major outage. Replacing the transformers will be costly and time consuming.

There are 3 13kv sources coming into the station and feeding the transformers. This might be an issue with three phase commercial customers in the case a transformer fails. The bushings styles installed in this station are hard to replace.

The single phase reclosers are very old and don’t have any spares. These are also not easily available in the market to replace. This is another issue that has been identified. Replacement will also be time consuming and expensive.

There is however no theft or vandalism in this substation as seen in some other outdoor stations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WB-1	479.5	WB-2	
WB-2	684	DH-3, GA-2	WB-1

Conversion Rank: 1

Suggested Decommissioning Year: 2009

Wellington

Year Built: 1960

Address: 227 MOHAWK ROAD EAST, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8 / 10

Condition Assessment / Comments

This facility is used as a storage / workshop for repairs on different equipment. This station has a huge amount of supplies, tools and gear which would require tremendous amount of relocation effort to an alternate facility where the work can be conducted. This is a severe consideration in the Conversion procedure.

The circuit breakers in this station are functionally problematic. Issues with the cell hardware and the relays have been evident in the past. The coils in the breakers burn up and require regular maintenance. The breakers deteriorate pretty fast while they are stagnated and freeze up.

This station is in overall good condition with no major failures in the recent past. There is a blast wall installed in the station to protect public safely in case of transformer explosion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WL-1	974	WL-8	
WL-2	1622	WL-9	
WL-3	868	WL-4	
WL-4	966	MT-6	WL-4
WL-5	1720	WL-11, WL-8	
WL-6	1474	WL-7, WL-9	EL-4
WL-8	1268	WL-10	WL-1, WL-5
WL-9	1442	MT-5	WL-2, WL-6
WL-10	773		EL-9, WL-8
WL-11	1699		WL-5

Conversion Rank: 16

Suggested Decommissioning Year: 2019

Wentworth

Year Built: 1930

Address: 681 KING STREET EAST, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 7 / 10

Condition Assessment / Comments

The station is extremely warm inside. This is caused by the windows shutout with steel plates to avoid vandalism. There have been various incidents of copper ground wires being cut out and stolen from the transformers. This has been done by climbing over a school side fence that separates the transformer bay and the school premises. This is also a potentially hazardous location to transformer failure and might be considered for building a blast wall.

The station has been very reliable with fairly new installations and metal-clad. The basement is dirty with signs of leaks from conductors.

There is a high pressure water pipe going through the basement of the substation which is in very bad physical condition. If this pipe ruptures it will cause the station to flood and will cause major equipment failure and potentially hazardous situation. There is a fiber-wired hub in the substation. There is a manhole from the basement leading to the street. These are major considerations that need to be attended for safety and Conversion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WT-1	1204	WT-11	WT-6
WT-2	1708	WT-11	
WT-3	1583		WT-4, WT-9
WT-4	1416	WT-3	
WT-5	1892	SP-3	
WT-6	1023	WT-1, WT-12	
WT-8	678		
WT-9	1057	SP-9, WT-3	SP-2
WT-10	992	HU-11	WT-12
WT-11	515		WT-1, WT-2
WT-12	631	WT-10	WT-6

Conversion Rank: 17

Suggested Decommissioning Year: 2019

Whitney

Year Built: 1963

Address: 252 WHITNEY AVENUE, HAMILTON

Facility: INDOOR S/S

Facility Condition Score: 8.5 / 10

Condition Assessment / Comments

This station has a similar indoor station setup to Stroud's Lane. The structure of the building is clean and stable.

Batteries of Circuit Breakers are nearing the end of life and will be changed soon.

The transformers are relatively new and in good condition. There have been no hardware issues in this station in the near past and functionally has been very stable.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WH-1	1545	ST-4, WH-4	
WH-2	1106	WH-6	ST-4
WH-3	1385	WH-4	
WH-4	644	WH-5	WH-1, WH-3
WH-5	1428	HA-1	WH-4, HA-1
WH-6	744		WH-2

Conversion Rank: 11

Suggested Decommissioning Year: 2015

York

Year Built: UNKNOWN

Address: 230 YORK ROAD, DUNDAS

Facility: OUTDOOR S/S

Facility Condition Score: 7 / 10

Condition Assessment / Comments

Recloser oil is leaking. This most probably is caused by oil-overflow.

The station has been functionally very stable with no major hardware failure. There is less effects of vandalism and theft in this station compared to other stations because of the secluded location of the property.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
YK-1	448	YK-2, YK-2.1	
YK-2	795	YK-1.1	YK-1

Conversion Rank: 25

Suggested Decommissioning Year: 2025

Grantham

Year Built: 1965

Address: 319 ½ GRANTHAM AVE.

Facility: INDOOR S/S

Facility Condition Score: 7.5 / 10

Condition Assessment / Comments

This station housed General Electric Circuit Breakers which have been problematic in the past. These are scheduled to be maintained next year.

The transformers are in pretty good functional and physical shape. The transformer T-2 is a bit noisy but is functionally stable. The transformer bay requires regular debris cleaning with is a maintenance issue that is troublesome.

There are new batteries for the station service transformer.

The station is in overall good condition.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
GRF1	3458	VEF3, GRF2	VEF3, GRF2
GRF2	2882	GRF1, GRF4	GRF1, GRF4
GRF4	2738	GRF2	

Conversion Rank: 1

Suggested Decommissioning Year: 2009

Taylor

Year Built:

Address: 100 CARLTON STREET

Facility: OUTDOOR S/S

Facility Condition Score: 5.5 / 10

Condition Assessment / Comments

The transformers in this station are the oldest in the system. The vibro acoustic test results show they are in okay condition. But the oil test results indicate that their insulation has experienced heavy degradation.

Automatic reclosers have been used to replace the breakers in this station. This has converted it to a potentially outdoor station, with the building having no functional use.

The transformer expulsion pipes point at each other and are thus a critical safety hazard in case of transformer failure. The oil from one transformer will be projected towards another one making it extremely dangerous. The outdoor structure housing the transformers is set up such that if one transformer fails, the other one has to be removed to replace the other one. This might cause long duration of downtime in case the issue arises. The complexity of the structure also makes it hard to maintain.

Overall, the station is very old and functionally risky. As mentioned above, major safety hazards are eminent in this station. The high voltage equipment is in easy access from the neighborhood. There are heavy signs of theft and vandalism in this station.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
TAF1	966	TAF2, TAF3	TAF2, TAF3
TAF2	966	TAF1, TAF3	TAF1, TAF3
TAF3	2204	TAF2, WEF2	TAF2, WEF2

Conversion Rank: 6

Suggested Decommissioning Year: 2011

Vine

Year Built: 1959

Address: 95 VINE STREET

Facility: INDOOR S/S

Facility Condition Score: 6.5 / 10

Condition Assessment / Comments

Vibro Acoustic Tests haven't been done on the transformers because it is not possible to run the test on this type of body structure. There is asbestos on the cable wrappings. These transformers have open conductors on top and are a potential safety hazard.

The expulsion pipe of one transformer points to another so, in case of explosion, all the oil from one transformer will be projected towards the other. This is a severe safety concern and needs to be attended to while transformer conditions deteriorate.

Circuit Breakers have been identified as functionally stable in the maintenance procedure. These breakers do have a lot of corrosion on their body. New batteries for the station service transformer have been installed.

This station has experience multiple occasions of copper theft in the past.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
VEF1	1945	VEF5	VEF5
VEF3	1441	GRF1	
VEF4	2579	VEF5, WEF1	VEF5, WEF1
VEF5	1873	VEF1, VEF4	VEF1, VEF4

Conversion Rank: 3

Suggested Decommissioning Year: 2009

Welland

Year Built:

Address: 136 WELLAND AVE.

Facility: INDOOR S/S

Facility Condition Score: 6 / 10

Condition Assessment / Comments

The conductors on top of the transformers are bare and are a potential safety hazard because this property is easily accessible from the roof of the neighboring building. There aren't any blast walls installed in this station.

The transformers in this station are functionally good. The vibro acoustic tests haven't been conducted on T-3 because it is not possible to conduct the test of this type of transformer body structure. The thermography test results have indicated absence of hot spots, so, they are not identified as immediate threats.

There is an open 4 kV bus bar inside the station which is also a major safety hazard. But this has been dealt with by installing a caution fenced door to restrict exposure.

The air circuit breakers have maintenance scheduled for next month. They have in the past shown sticky contacts and deteriorate fast when stagnated.

Although this station is pretty good physical and function condition, it has major safety issues associated to it.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
WEF1	1239	WEF2, VEF4	WEF2, VEF4
WEF2	1441	WEF1, TAF3	WEF1, TAF3
WEF4	720	VEF5	VEF5

Conversion Rank: 7

Suggested Decommissioning Year: 2012

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Horizon Utilities Corporation

4kV & 8kV Renewal 2009

Prepared By:
Network Department

Executive Summary

Horizon Utilities Corporation distributes electricity to approximately 233,000 customers in the Hamilton and St. Catharines area. Among the entire customer base, 82,000 customers are served from the 4.16 kV and 8.32 kV voltage levels. The distribution system in these parts of the service area was mainly created in the 1950s, which implies that the distribution assets are nearing the end of reasonable life span thus exposing Horizon to high risks and consequences of failure. A combination of growing population in the area demanding increase in capacity, changing distribution system standards and aging infrastructure makes it imperative to replace these assets. Continuing to sustain this old infrastructure will cause the reliability levels to degrade as unplanned outages due to defective equipments increase.

These aging assets are not required in the future and will provide capital savings opportunities, system efficiencies can be achieved with lesser substation transformer losses, operating efficiencies will be gained with lower response times to system emergencies and security improved through reduction in boundary areas by having more ties to adjacent feeders. Thus it is more beneficial for Horizon Utilities to replace the assets to the higher voltage levels of 13.8 kV or 27.6 kV from the 4.16 kV and 8.32 kV voltage levels. This 4.16 kV and 8.32 kV system renewal plan is a detailed study on the distribution system to justify and prioritize the decommissioning and capital reinvestment requirements in these Horizon Utilities Corporation service areas.

The 4.16 kV and 8.32 kV voltage level renewal plan outlined in Section 3 contains a specific order of suggested areas to be renewed. This area-wide renewal approach is based on operating and backup capabilities within the substations that reside in these areas. As Horizon Utilities is the amalgamation of 6 different cities and through expansion and acquisition, the 4.16 kV and 8.32 kV areas take the shape of operating "Neighborhood Clusters" wherein the substations within each area back each other up. Thus it makes inherent sense to initiate the renewal with an area-wide focus. It is recommended adequate backup capability be maintained within the areas as they are renewed.

Based on the results of the study, the distribution system fed from the following substations will be renewed by converting from the 4.16 kV to the 13.8 kV voltage level or from the 8.32 kV to the 27.6 kV voltage level in the following order:

St. Catharines
Hamilton Downtown
Hamilton West
Hamilton Mountain
Hamilton East
Stoney Creek
Dundas

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1. Introduction

Horizon Utilities Corporation is the third largest municipally owned electricity distribution company in Ontario. It provides electricity and related utility services to over 233,000 residential and commercial customers in Hamilton and St. Catharines. The electricity distribution system entails several voltage levels ranging from 4.16 kilovolts (kV) to a maximum of 27.6 kV.

Although the majority of the customer base in Hamilton and St. Catharines is served from the 13.8 kV and the 27.6 kV distribution voltage levels, approximately 82000 customers are served from the 4.16 kV and 8.32 kV levels. These areas include 30 substations among which 26 are in Hamilton and 4 are in St. Catharines. In these service areas, the assets are nearing the end of life. This poses the threat of incurring unanticipated outages due to equipment failure and high capital expenditure levels. Also, some parts of the distribution system within the 4.16 kV and the 8.32 kV voltage levels are being operated at maximum capacity with restricted backup capabilities in case of unplanned outages. Renewing assets by converting these parts of the system to a higher voltage will result in lower maintenance costs, higher reliability indices and increased customer satisfaction and avoid capital and maintenance costs associated with maintaining aged station assets. The renewal projects entail an upgrade of all the distribution system assets to the higher voltage standard and the removal of load from the substations allowing them to be decommissioned.

The plan provides Horizon Utilities Corporation with a decision model to justify and prioritize capital projects by organizing capital investments in different parts of the 4.16 kV and 8.32 kV voltage service areas allowing Horizon Utilities to have predictable capital expenditure levels for the future and achieve and sustain higher system reliability levels.

Based on the information available at this time, it is suggested that the recommended conversion area order be followed. But it is also essential to recognize the scope of the renewal plan to be a high level outline. Detailed analysis is required on individual feeders at the time projects are to be issued. It is recommended that any additional information available at the time of renewal that might affect the outcome and scope of the conversion project be utilized.

Similarly, with the progress of Asset Management Implementation Program better asset nameplate, maintenance data and condition data available should be incorporated into the data analysis. This would enable better condition assessment of the assets and enable more timely investment decisions on the 4.16 kV and 8.32 kV system renewals.

2. Background

This 4.16 kV and 8.32 kV renewal plan is a system-wide study on the 4.16 kV and 8.32 kV voltage level service areas to prioritize capital investments requirements and develop recommendations regarding decommissioning of each of the 30 substations in the Horizon Utilities service area.

The plan has been based on the results of the following projects:

- **Health Index Model** – The health index model had been previously generated for transformers, poles and cables to capture the different variables affecting the end of life of the assets. This end of life criteria has been used to predict an approximate replacement date for the assets. The final renewal plan has been developed to consider the time when majority of the assets tied to a feeder are due for replacement. This process is utilized to ensure that the 4.16 kV and 8.32 kV distribution areas are converted to the higher voltage levels before the majority of the distribution assets have reached their end of life and would pose a risk of failure. It is also economical to upgrade these service areas to the higher voltage levels instead of replacing the assets through the regular asset renewal process. When better condition data has been captured, the health model needs to be re-evaluated to better represent the renewal needs of the service area.

- **Station Condition Evaluation** – The substation assets in Horizon are maintained through a regular maintenance cycle. It is suggested that any foreseeable failure condition for the assets is attended to on a prioritization basis. A formulated condition evaluation of substation is required to capture the actual condition of these substations. In order to incorporate the condition of each substation as a driver for the plan development and in the absence of actual condition assessment data, each substation was evaluated on a 5-point condition rating ranging from excellent to critical based on the criteria building access, physical facility condition, power transformer, switchgear and safety / environmental. These ratings were then weighted to derive a final condition score for the substation.

- **Age Estimation Report** – The age estimation report has estimated the age of major assets in our distribution area that had missing installation dates associated to them. These estimated ages have been used along with end of life criteria to derive the replacement date for the major asset classes. This replacement date has been used to develop the final renewal plan.

- **System Operability Analysis** – The Horizon distribution grid contains multiple self-contained clustered areas. All the substations within each area back each other up through feeder-ties. This system structure led us to the deduction that the conversion needs to be done on an area-wide basis where the operability is maintained as the conversion proceeds. That is why an area score has been developed to come up with the renewal order.

The key parameters of the project are:

- Distribution Asset Age
- Substation Asset Condition
- Distribution System Arrangement
- Feeder Dependency
- Customer Impact
- Source Availability
- Cost of renewal
- Safety and environmental risks

The assumptions used in the process of developing the renewal plan and they are as follows:

- The design group will assess every feeder in detail to develop a conversion design at the time of renewal.
- The renewal plan is developed based on a like-for-like replacement for distribution assets.
- The asset condition data not available currently will be incorporated in future periodic reevaluations of the plan once Asset Management processes have been clearly defined and established.
- If any major assets in the substations fail or load capacity increase is required, the plan should be re-evaluated to justify the conversion of the whole feeder or parts of the feeder and accordingly the plan should be adjusted to capture the effects of the change.
- GIS data used in the renewal plan is somewhat reliable and in the case additional information is available, it should be incorporated into the plan.

This plan is based on GIS data and a combination of past initiatives like Health Index Model and Asset Age Estimation report. The substation condition has been developed through a condition matrix developed through rating attributes associated to each station. The renewal plan is suggested to incorporate the Asset Management data-collection initiatives which will provide improved justification for the capital expenditures identified in future periodic re-evaluations of the plan.

3. Renewal Plan

The final area score derived through the methodology described in section 4 will enable Horizon to focus renewal activities in those areas. Based on the current data availability, the analysis results in a score for each identified area as follows:

St. Catharines
Hamilton Downtown
Hamilton West
Hamilton Mountain
Hamilton East
Stoney Creek
Dundas

These results bring certain issues into specific relief:

1. The combined and individual evaluations of distribution assets and station assets clearly point to St.Catharines as the area that appears by a definite margin to have the most urgent need for renewal.

2. The station evaluations point to the substations Taylor, Webster, Caroline and Hughson as having significantly greater need for either renewal or decommissioning than many others in the Horizon 4.16 kV and 8.32 kV areas.

Recommendations:

1. Horizon Utilities should adopt voltage conversion as the organization's strategy for 4.16 kV and 8.32 kV Asset Renewal.

2. This strategy should commence with the 2009 construction year focusing on the areas of greatest or most urgent need, namely St.Catharines and Hamilton Downtown.

3. The organization should determine an appropriate rate of progress for the program and accordingly involve resources to this renewal program.

4. The organization should include in its future capital plans a program of investment in substation assets that will ensure the reliable performance of the stations until their anticipated decommissioning dates.

5. Adequate maintenance programs should continue in these areas throughout the life of the renewal program.

6. That substation transformer testing is continued on a regular basis at a frequency consistent with the risk.

7. That the organization acquire detailed substation condition evaluations from an independent expert source in order to improve the quality of data used in the renewal prioritization model.

4. Renewal Plan – Design Criteria and Methodology

The 4.16 kV and 8.32 kV voltage level renewal plan entails recommended order of conversion to the 13.8 kV or 27.6 kV voltage level. The replacement of the 4.16 kV and 8.32 kV assets is according to a logical plan – that reduces risk by replacement in an order that minimizes the risk of end of life failures and minimizes investments in the station assets. The order of recommendation is based on the drivers that have been identified as design criteria to provide the most suitable justification for undertaking the conversion projects. These drivers are utilized in various ways in the different stages of plan development to derive a detailed scoring methodology to analyze each of these feeders. Based on this scoring methodology, the feeders are evaluated in comparison to each other leading to a final area ranking. The methodology of the renewal plan is broken down into the Feeder Ranking, Substation Condition Scoring, Cost Analysis and Recommendation Feasibility Analysis procedures. The criteria are used as inputs to each of these design procedures to provide adequate results to derive the outputs used eventually to come up with the final plan.

4.1. Criteria

Following are each of the criteria and their contributions in the different stages of the design methodology procedures:

Distribution Asset Age

Upgrading the aging distribution assets is one of the major drivers behind the conversion projects in Horizon Utilities. The distribution assets in the 4.16 kV and 8.32 kV voltage level service areas are nearing their end of life and in some cases running at capacity. The Security Planning process ensures that we reduce the impact of unplanned outages due to the failure. Based on the demographics of the distribution assets found in the GIS, not adopting a proactive replacement strategy would result in high levels of capital expenditures and higher operating and maintenance costs as reactive replacements is more expensive that planned replacement. It is also inefficient to replace each asset individually via existing renewal program and through this renewal plan the replacement time will be optimized thus allowing effective decommissioning of the stations. The renewal plan accommodates the proactive replacement of these aging assets. The assets considered are transformers, poles, conductors and cables. Under the Substation Ranking procedure, the average age and probabilities of failure of these assets are utilized to come up with a weighted score that has been created to evaluate each of the substation area condition relative against each other. This was used to derive a substation area conversion rank and eventually utilized in the final renewal plan.

Substation Asset Condition

The major assets in a distribution substation are power transformer, Bus Bar, Circuit Breakers, Feeder Cables and physical facility. The substation assets are managed through extensive maintenance programs and analyses of the results are used to predict failure modes. Long-Term capital Investments on substation assets are difficult to predict and it is suggested to continue to attend to the assets requiring immediate attention be repaired when such failure modes are observed. For the purpose of capturing the substation condition to justify the year of decommissioning, the substations have been individually visited to document the overall facility condition, safety and environmental concerns, past records of major failure and recent or impending major investments. These visual observations are documented in section 7 of this report.

Development of an accurate health index for station assets requires an independent examination and assessment of station assets to determine areas of greatest risk and impact and it is recommended this be achieved over the next 3-5 years, resulting in continually more accurate assessments of which assets are in greatest need of replacement. For initial consideration in the plan, a substation condition matrix was developed which rates each substation based on five different condition criteria ranging from excellent to critical condition. The Horizon Substation Manager, possessing the most immediate comprehensive knowledge of the substation asset conditions, rated each substation based on each of these attributes. The attributes are substation access, physical building condition, power transformer condition, switchgear condition and safety / environmental risk. The ratings are documented with adequate reasoning. All these ratings were weighted based on relative importance to derive a final substation condition score.

At present, we have a simplified in-house assessment of the major factors outlined earlier. It is proposed that this assessment form the basis for the initial years of the renewal program, but that it is revisited as independent survey data is acquired for each station.

Feeder dependency

Horizon Utilities 4.16 kV and 8.32 kV distribution feeders are operated with a detailed contingency plan ensuring redundancy and load transfers capabilities in case of failure. The Horizon distribution area, when studied for backup feasibility, shows that there exists an area based structure where a group of substations back each other up through tie points between feeders. This makes the areas or clustered primarily self-contained with minimal backup between the areas. This prompted development of an area-based ranking that ensures that the operability is maintained while the feeders are renewed at the higher voltage.

An analysis of feeders which have ties to adjacent substations identifies that the 30 substations remaining in the system can be broken into the following operating areas–

Dundas (4 stations – Baldwin, Highland, John and York)
West Hamilton (2 stations – Stroud's Lane, Whitney)
Downtown Hamilton (4 stations – Aberdeen, Hughson, Central, Caroline)
East Hamilton (7 stations – Bartonville, Cope, Kenilworth, Ottawa, Parkdale, Spadina, Wentworth)
Hamilton Mountain (5 stations – Eastmount, Elmwood, Mountain, Mohawk, Wellington)
Stoney Creek (4 stations – Deerhurst, Dewitt, Galbraith, Webster)
St. Catharines (4 stations – Grantham, Welland, Vine, Taylor)

Each of these areas is more or less islanded from other operating areas, but contains multiple ties to other feeders within the same area. Accordingly, it is believed that by assessment of total health indices for the area, rather than by individual station areas or feeder areas, it is possible to ensure that as the program progresses, support from other feeders within the same operating area will be available and consequently, security of supply to all customers is retained.

Customer Impact

The number of customers connected into each feeder has been considered in the renewal plan. The customer score has been created weighting the commercial customers higher than the residential customers. This has been accommodated in the final renewal plan in the distribution feeder weighted probability of failure. The reasoning behind this is that there is a higher impact of failure for a feeder supplying a higher number of customers.

It is understood that converting to the higher voltage level negatively affects the reliability statistics because a fault in any part of a 13.8 kV or 27.6 kV voltage levels would affect a large number of customers. As a renewal project would entail replacing all assets in an area, it is expected that outages caused by defective equipment will be reduced in the process. With the progress of the Smart Grid Strategy Implementation, other solutions such as installing mid-line reclosers, remote operable switches etc. will allow better maintenance of reliability levels.

Cost of Renewal

The cost of renewal is another major driver in the renewal process as well as the final suggested time of conversion of the feeders. The renewal costs were evaluated based on a like for like replacement of major distribution assets. An innovative automated cost estimated tool was created to evaluate the conversion costs for each feeder. The tool can be used for estimating feeder renewal cost, anticipated capital expenditure levels for each substation and costs of deferring renewal.

Cost of Substation Upgrade

The major substation assets like power transformers, breakers based on the number of feeders have been used as an estimate of the cost of substation upgrade. This would be used as a major consideration to decide between investment in the distribution system renewal in the form of conversion and substation upgrade by replacing assets.

4.2. Methodology

As mentioned earlier, the Renewal Plan is based on the area ranking that shows the order in which the area within the 4.16 kV and 8.32 kV distribution grids needs to be converted. This Area Score is derived from a combination of the Feeder Weighted Probability of Failure, Substation Condition Score, Feeder Conversion Cost and Substation Upgrade Cost. The following is a detailed explanation of how these were utilized to derive the area-based final renewal plan.

Feeder Weighted Probability of Failure

The feeder weighted probability of failure is developed through a weighted sum of median probability of failure of all units of transformer, poles and sections of cables and conductors. In this procedure, initially, the GIS information on major distribution assets connected to each feeder has been captured together in one database to provide adequate scoring capabilities. For each of these assets, the data collected are Asset ID, Probability of Failure and Replacement Costs. Based on the average probability of failure and adequate weighting for each asset class based on their costs and impact of failure, a final weighted probability of failure of assets has been calculated for each substation. This resulted to the overall substation probability of failures and decommissioning ranks.

Substation Condition Scoring

Each substation was ranked based on scores received on five different attributes that characterize the condition of the substation. The attributes are substation access, physical building condition, power transformers, switchgear and safety / environmental condition. Each attribute was rated based on a five-level criteria ranging from excellent to critical. Based on the rating on each criterion, a final weighted condition score was derived for each substation.

Note: Refer to Section 7 for the Substation Condition Scorecards. This information is useful during the decommissioning of the station.

Feeder Conversion Cost

An innovative and automated Cost Analysis tool has been developed to calculate the feeder conversion costs. All the substation and distribution Asset ID, Probability of Failure and Conversion Cost have been captured in one database. Then the analysis tool has been developed to use all this data to calculate the total cost of feeder conversion, project Capital Expenditure levels for each substation and the cost of deferring conversion for each substation. The Cost Analysis tool is completely dynamic and if in the future if this plan is re-evaluated, this tool can be used again with updated information available at that time to re-calculate the Conversion Costs. The results of the tool have been cross-verified with project estimates conducted by the Engineering Design group to check its accuracy. It has been observed to be accurate and comparable to the estimates, validating its methodology and approach of the calculation procedure.

Substation Upgrade Cost

The substation upgrade cost is used to estimate the value of the substation assets. This estimate is based on the cost of replacing major assets like the power transformer and switchgear.

Area Score

The final area score has been developed by combining the weighted probability of failure score for distribution assets connected to each substation and the substation condition score.

The range of values for the probability of failure score and the substation condition score are normalized to bring the order of the numbers to a similar range. Then these values are weighted based on the ratio of the cost of the replacement of the assets to finally combine to an area score. This final area score rates the operating clusters within the Horizon network into a final rank by calculating the average station area score. The results are presented in Sections 3 of this report.

5. Conversion Maps – Horizon Service Area

The following are the GIS Maps showing the areas served by the 4.16 kV and 8.32 kV voltage levels in the Horizon Utilities Corporation Service area.

Service area – Hamilton

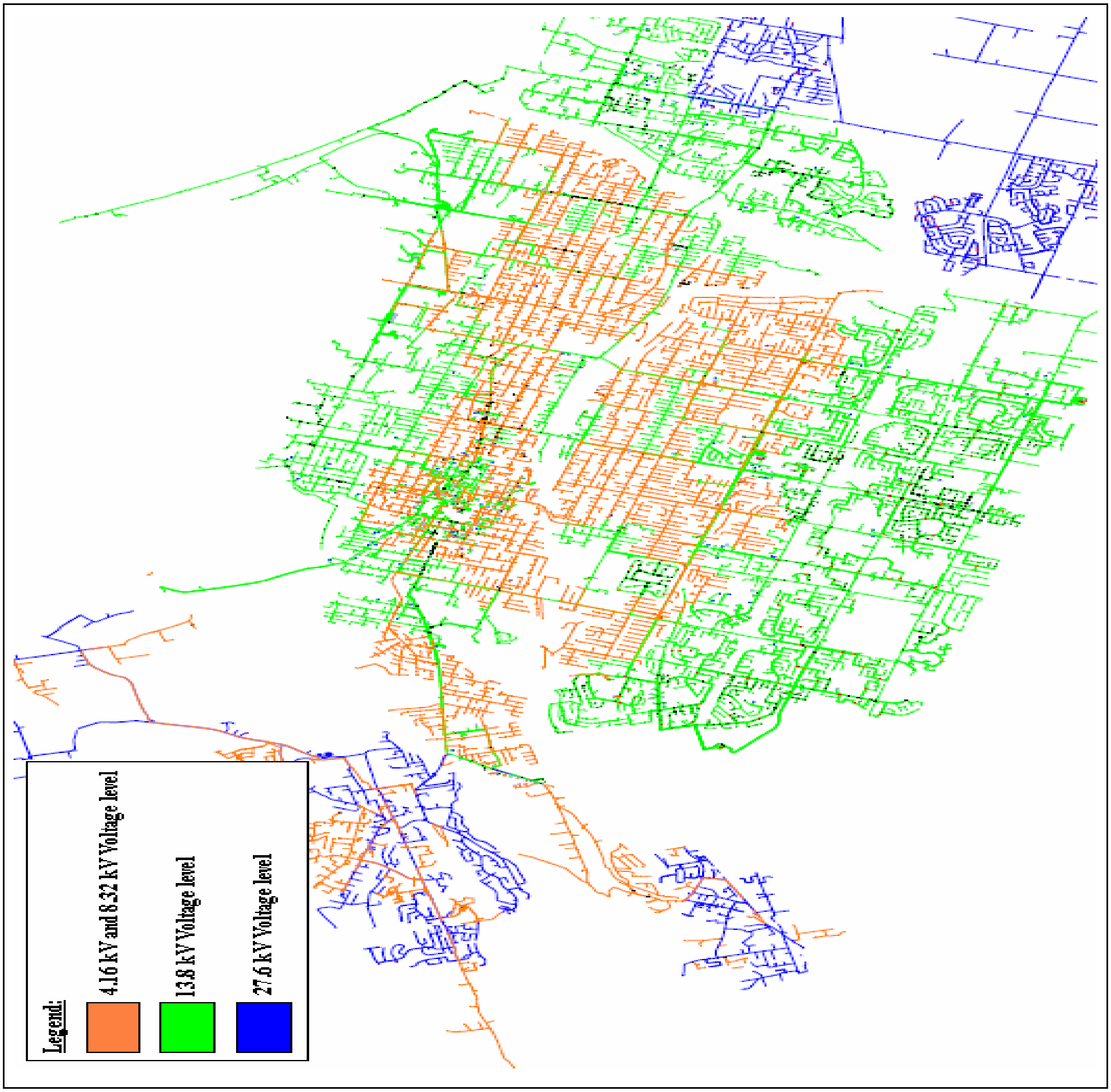


Figure 1

Service area – St. Catharines

Figure 2

Hamilton Area Operating Clusters

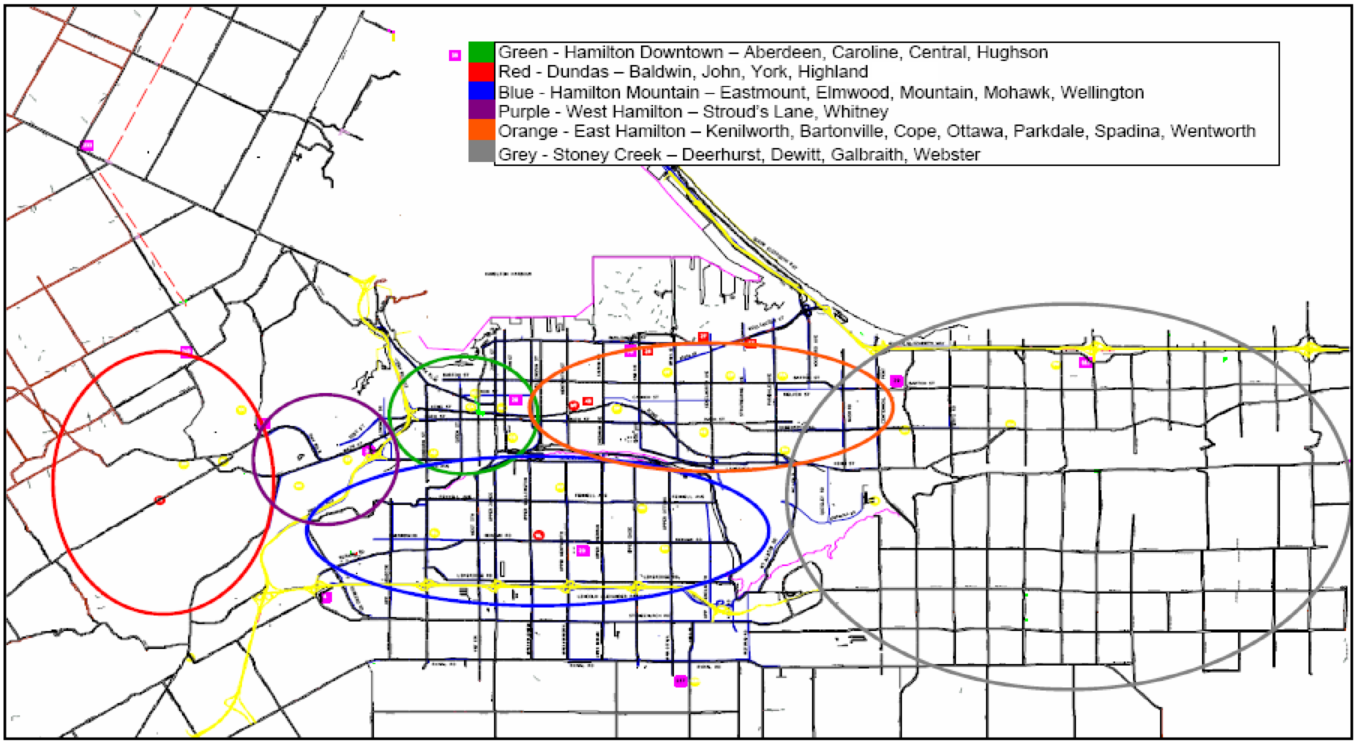
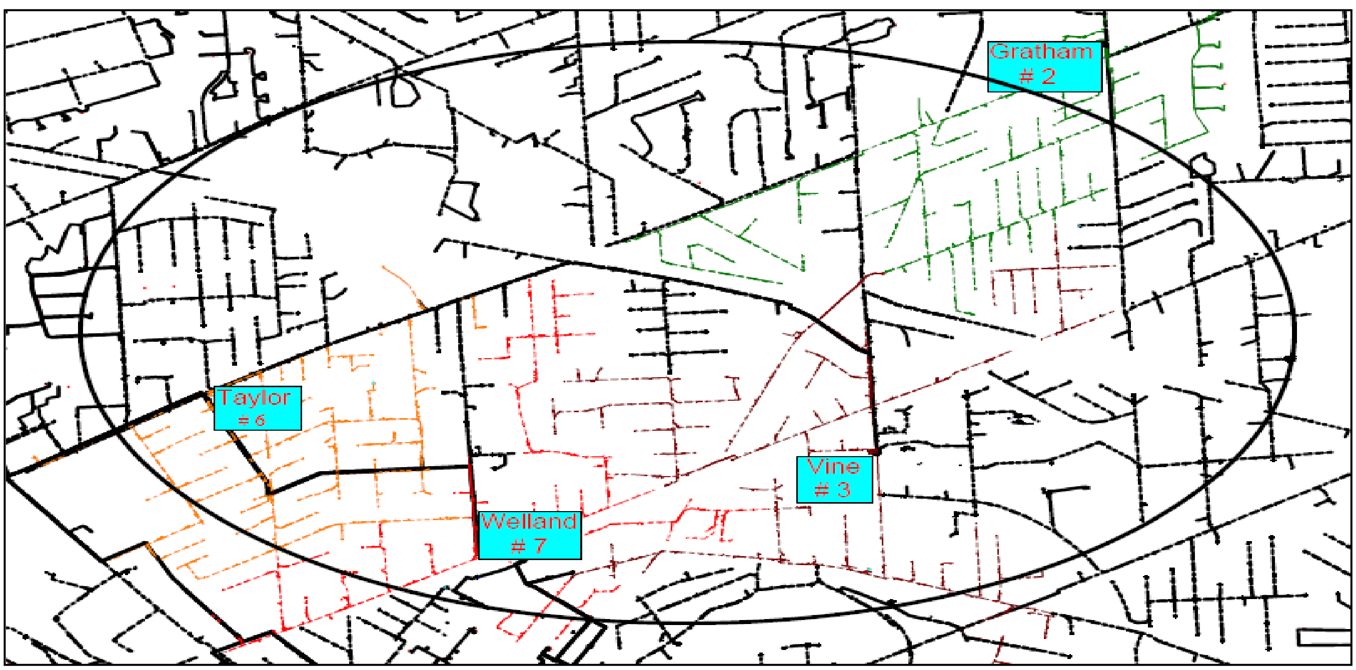


Figure 3

St. Catharines Area Operating Cluster



Aberdeen

Year Built: 1969

Address: 416 ABERDEEN AVENUE, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

The facility has slite roof which is harder and more expensive to maintain. It also has a blast wall installed to protect the neighbors' in case of transformer explosion.

Then breakers are in pretty good shape. They have been overhauled recently. The parts for these kinds of circuit breakers are hard to find in case of required replacements. There are a couple of spare circuit breakers in this substation. The batteries for the station service transformer have been changed recently.

The transformers are in really good condition. There had been hot spots reported in them in a past thermography test result. These issues had been dealt with from them. They are overall in pretty good condition.

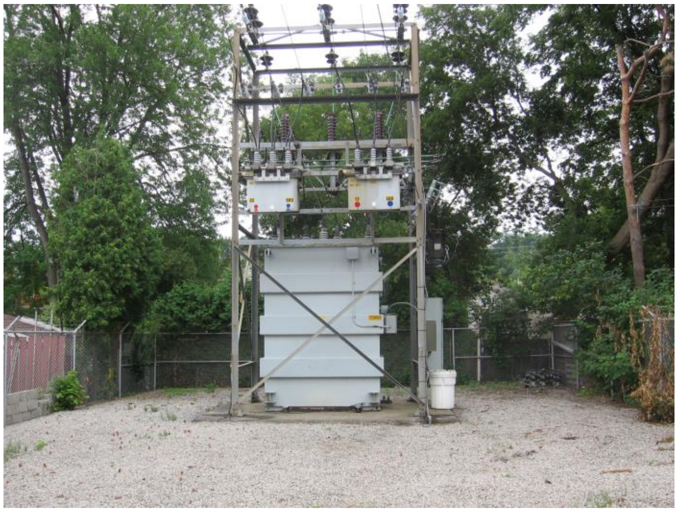
Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
AB-1	1775	AB-2	
AB-2	1371	CA-3	AB-1, AB-5
AB-3	1486	AB-5	
AB-4	1646	CA-5	
AB-5	1820	AB-6	

Substation Name: Aberdeen S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)		X			X
Condition: 2 (Good)				X	
Condition: 3 (Fair)			X		
Condition: 4 (Poor)	X				
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Alley, Bus Route, Confined Space		Pin Hole, Leak Detected in T2	ACBs installed	Asbestos is present but managed

Baldwin



Year Built: UNKNOWN

Address: UNKNOWN

Facility: OUTDOOR S/S

Visual Assessment / Comments

Standard outdoor station build standard. Past corrective maintenance has entailed occasional recloser switching issues caused by delayed hydraulic reaction times for switch closing. This is mainly caused by unbalanced oil pressure which has caused issued regarding variable resetting times.

Rusting on the support structure may be an issue to look into in the future. This location has seen fewer effects of theft and vandalism primarily due to the secluded nature of the property and unexposed boundaries on 3 sides.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
BD-1	2,485	BD-2	JN-1, JN-2
BD-2	940	YK-2	BD-1

Substation Name: Baldwin S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X				
Condition: 3 (Fair)		X	X		
Condition: 4 (Poor)				X	X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Vegetation problems due to close garden			Oil Reclosers are used	Close to neighborhood

Bartonville

Year Built: 1952

Address: 2355 KING STREET EAST, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

The facility has slite roof, which is harder and more expensive to maintain.

There is 1 transformer in the station and has been very reliable in the past. This substation houses 1 spare transformer. The transformer is relatively new (built – 1985) and is in very good condition. There is no spill containment in the transformer base and is a possible environmental issue to be noticed.

The Oil Circuit Breakers (OCB) are free breathers and absorb moisture from the atmosphere. This makes them more expensive to maintain. They are in a 3-year maintenance cycle and the ones in this station will be replaced by the end of the 2007.

There are three 13.8 kV sources coming into the station which provides it with greater redundancy and reduces the amount of risk associated to the station. The end of 2007 as backup to reduce risk associated to transformer failure is connecting the existing spare transformer in this substation.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
BA-1	1305	BA-4, PA-5	BA-2
BA-2	928	BA-1	KE-5
BA-3	559	BA-4, BA-7	
BA-4	1743		BA-1, BA-3, KE-6
BA-7	971		BA-3

Substation Name: Bartonville S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)	X	X	X		
Condition: 2 (Good)					X
Condition: 3 (Fair)				X	
Condition: 4 (Poor)					
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason					

Caroline

Year Built: 1955

Address: 117 MARKET STREET,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

Both the transformers are in pretty bad shape. Pyro wires have blown in the past and have been taken off completely. The fans are not working and the gauges are broken. Heavy corrosion is visible on the conduits, studs and fittings are broken. There are signs of oil-leaks and are weeping down the gaskets. The relays mounted on the transformers are extremely old. Overall the transformers are extremely rusty with signs of oil-leak on the body and ground. Maintenance work is also difficult because of condition.

Air Circuit Breakers in this Substation are in extremely good condition and are suggested to be stored as replacements for other stations having similar equipment. This is due to their reliability and efficiency in maintenance procedures.

The electrical panel is relatively new in this substation.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
CA-3	1442	CA-5	AB-2
CA-4	2216	HU-6	HU-4, HU-5
CA-5	1232	CE-2	AB-4, CA-3
CA-6	1233	CA-8	
CA-7 / HU-12	362		
CA-8	374		CA-6

Substation Name: Caroline S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					
Condition: 3 (Fair)		X			
Condition: 4 (Poor)	X				
Condition: 5 (Critical)			X	X	X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Access close to public		Oil leaks on both, is being managed	Signs of overheating on alternate bus	No blast walls, vandalism, exposure to neighbor

Central

Year Built: 1950

Address: 193 JOHN STREET SOUTH,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

Transformers are relatively newer (1980s). One transformer failed in 1995 and was replaced. This station hasn't faced any transformer related issues since 1995.

Breakers in this station have posed operating issues and might require maintenance in the near future. The metal clad is old with unimpressive mechanical fit and finish. This causes inefficient maintenance operations.

The electrical panels were replaced in 1997. New batteries have installed in 2006.

There is a manhole going from the basement of the station to the street side. An added consideration if property sold including the building.

The station overall is very clean. The station is in much better shape and condition with new equipment than other stations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
CE-1	671		
CE-2	1100	CE-8	CA-5
CE-3	1056	CE-10, CE-8	
CE-4	1431	CE-11	CE-5
CE-5	390	CE-4	
CE-6	225		
CE-8	834		CE-2, CE-3
CE-9	137		
CE-10	1458		CE-3, MT-10
CE-11	1102	CE-4	

Substation Name: Central S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					
Condition: 3 (Fair)		X	X		X
Condition: 4 (Poor)	X				
Condition: 5 (Critical)				X	
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Access share with staff parking lot		Transformer on slant	OCBs and ACBs, have to use deathsticks	

Cope

Year Built: 1965

Address: 1430 BARTON STREET EAST,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

The Transformers and Air Circuit Breakers (ACBs) in this station have been very reliable in the past. No instances of major maintenance work have been done. One of the transformers has been recognized as noisy but has sound functional integrity.

This station has a Fiber-Optic junction point and is a consideration during conversion, as an early notification is required to relocate it.

Overall, the facility is in very good shape with no major issues to be aware of.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
CP-1	997	CP-9, PA-5	KE-2
CP-2	1802	CP-8	
CP-3	999	PA-9	
CP-4	651	PA-3	CP-7
CP-5	1938	CP-6, OT-5	
CP-6	1046		CP-5
CP-7	1543	CP-4	OT-4
CP-8	673		CP-2
CP-9	1807		CP-1

Substation Name: Cope S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X	X			
Condition: 3 (Fair)					X
Condition: 4 (Poor)			X	X	
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason			1 noisy transformer in bay	ACB's need new contacts	

Deerhurst

Year Built: UNKNOWN

Address: 357 Hwy # 8

Facility: OUTDOOR S/S

Visual Assessment / Comments

This outdoor property is leased. The station is functionally very sound with no major issues experienced in the past. The transformer is in very good condition

The current transformers are not working properly and are under investigation.

The single-phase reclosers are suggested for replacement by three phase reclosers to increase reliability. Overall, there is no safety, reliability or environmental issues in this station. This station has been identified as one of our best substations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
DH-1	2766	DH-2, DW-2, DW-3	
DH-2	1268	GA-2	DH-1, DW-1
DH-3	3343	GA-2	WB-2

Substation Name: Deerhurst S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)		X			
Condition: 2 (Good)			X		
Condition: 3 (Fair)					
Condition: 4 (Poor)				X	X
Condition: 5 (Critical)	X				
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Difficult access with heavy equipment, some vandalism			3 ph and 1 ph reclosers	Close to neighbor, birds nesting

Dewitt

Year Built: UNKNOWN

Address: DEWITT ROAD, STONEY CREEK

Facility: OUTDOOR S/S

Visual Assessment / Comments

The transformers have automatic tap changers and are hard to maintain. These transformers are in pretty good condition and have performed reliably in the past. The equipment are mounted on the old structure going from over the transformer and in case of transformer replacement, this part of the structure has to be disassembled.

This station also has single-phase reclosers that are suggested for replacement by three phase reclosers to increase reliability of the station and have minimal impact on three phase commercial customers in the case of failure.

This is a lightly loaded station and poses very little cause of concern. The station is exposed to salt and debris because of the location of the station beside the QEW. There is no sign of theft or vandalism in this station as seen by some other outdoor substations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
DW-1	2,299	DH-2, DW-2, DW-3	DW-3
DW-2	144	DW-3	DH-1, DW-1, DW-3
DW-3	1,440	DW-1, DW-2	DH-1, DW-1, DW-2

Substation Name: Dewitt S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)			X		
Condition: 3 (Fair)					
Condition: 4 (Poor)	X	X		X	X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Close to industry, fence damage, soft ground (low & wet)		Only TX with ULTC active	1 ph recloser, old	Close to industry, QEW highway

Eastmount

Year Built: 1959

Address: 856 MOHAWK ROAD EAST,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

Window operators don't work causing lack of ventilation in the premises.

The Air Circuit Breakers have experienced reeking problems causing maintenance issues.

A lot of oil has leaked from the transformers and is an issue to look further into in the future. Environmental assessments and heavy clean up is required as part of the Conversion procedure.

Fiber-wired junction point exists in the building and they should be notified well ahead of Conversion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
EA-1	1035	MK-1	MK-11
EA-2	1378	EA-10	MK-2
EA-3	1771		EA-8, MK-10
EA-4	680	EA-6, EA-11	
EA-6	1568		EA-4
EA-7	1192	EA-9	
EA-8	1819	EA-3	
EA-9	1394		EA-7, MK-6
EA-10	1250		EA-2
EA-11	1381		EA-4

Substation Name: Eastmount S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)			X	X	X
Condition: 3 (Fair)	X	X			
Condition: 4 (Poor)					
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason					

Elmwood

Year Built: 1958

Address: 218 WEST 19TH STREET,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

This station has a blast wall installed to protect neighbors in case of a transformer explosion.

Air Circuit Breakers are in good shape and have been overhauled last year.

There is a fiber-wired junction point inside this station. This is a special consideration during conversion, as early notification to relocate it is required.

The transformers are leaky and have been identified for maintenance next year. Overall, the transformers are in pretty solid condition with no known history of failure or defect.

The batteries are in good shape. The station service transformers, like all other stations, have no spill-containment and in a possible hazard to be looked into.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
EL-2	1087	EL-8	
EL-3	1038	EL-7	
EL-4	1331	WL-6	EL-7
EL-5	1543	EL-10	
EL-7	1219	EL-4	EL-3
EL-8	1387	EL-9	EL-2
EL-9	908	WL-10	EL-8
EL-10	374		EL-5

Substation Name: Elmwood S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)		X	X		X
Condition: 3 (Fair)				X	
Condition: 4 (Poor)	X				
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Access for heavy vehicles is difficult			Issues with relays	

Galbraith

Year Built: 1959

Address: 16 GALBRAITH DRIVE,
STONEY CREEK

Facility: OUTDOOR S/S

Visual Assessment / Comments

This station Oil Circuit Breakers (OCB) housed inside metal enclosures. They are in relatively good shape and functionally sound. There is minimal maintenance required in the substation.

The transformers have performed reliably in the past and are in pretty good condition.

There are extensive effects of copper theft and vandalism in the station based on its location and neighborhood.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
GA-1	156	GA-2	GA-2
GA-2	407	GA-1	DH-2, DH-3, GA-1, GA-3, WB-2
GA-3	2	GA-2	

Substation Name: Galbraith S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)	X				
Condition: 2 (Good)			X		
Condition: 3 (Fair)		X			
Condition: 4 (Poor)					X
Condition: 5 (Critical)				X	
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Vandalism			1 of a kind recloser, heavy maintenance required	In park setting, close to public & Hwy 8

Highland

Year Built: 1977

Address: 259 GOVERNORS ROAD,
DUNDAS

Facility: INDOOR S/S

Visual Assessment / Comments

Facility is shared with Hamilton Waterworks housing a water pumping station. This will require special consideration during the whole decommission procedure as we don't have access to there part of the facility and holds parts of our equipment. The water pump is fed off our feeder and will need to be recognized as part of the upgrade.

New batteries for Circuit Breakers will be installed soon. Unique auto-recloser feature installed with circuit breakers.

This substation has experienced signs of extreme vandalism and theft in the past in the form of shots from air soft guns from the neighborhood and fenced being cut off from the property. There is also animal intervention in the property. As the property is below ground level, during winter large amounts of snow piles up around the transformer bank, which makes it potentially hazardous. These environmental aspects make maintenance procedures extremely difficult and major safety threats ensue.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
HI-1	743		
HI-2	670	JN-1	HI-1, HI-3
HI-3	1133	HI-2	

Substation Name: Highland S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)			X	X	
Condition: 3 (Fair)		X			
Condition: 4 (Poor)					
Condition: 5 (Critical)	X				X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Some vandalism, rodents. Due to slope, building below surrounding grade, access is difficult.			ACB's, electronic recloser.	Close to home, Low area, possible flooding, pumping station

Hughson

Year Built: 1926

Address: 48 HUGHSON STREET NORTH,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

Transformer T-2 is not very reliable. Vibro-Acoustic testing on the transformer has indicated loose winding in the transformer. All four transformers are housed inside enclosed transformer bay which make maintenance work difficult and also hazardous in case transformer catches fire. Risk can be reduced if one transformer is taken-off as this is station is lightly loaded. The oil will also spill into the basement causing massive safety issues.

Plastic Pellet switches inside the air circuit breakers (ACB) have been found broken and has required replacement several times in the past. There have been no other issues experienced regarding the ACBs and are generally very reliable.

The SCADA interface cabinet for all stations is housed in this station facility and is extremely sensitive to any kind of failure and will cause major disruption to our system operation.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
HU-2	600		
HU-4	1048	CA-4	
HU-5	1287	CA-4	
HU-6	1600	HU-7, HU-11	
HU-7	1216	HU-11	HU-6
HU-8	155		
HU-9	208		
HU-10	519		
HU-11	1490	WT-10	HU-6, HU-7

Substation Name: Hughson S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)				X	
Condition: 3 (Fair)					
Condition: 4 (Poor)	X	X	X		
Condition: 5 (Critical)					X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Share access with office TX removal difficult		T2 – Suspect loose windows	New ACBs parts are plastic and brittle	TX oil spill / fire will be catastrophic

John

Year Built: 1985

Address: 150 HATT STREET,
DUNDAS

Facility: OUTDOOR S/S

Visual Assessment / Comments

This substation has the same outdoor station structure as Baldwin S/S and York S/S.

Facility houses 1 spare transformer. Premise has been affected by extremely vandalism in the past in the form of stolen fences and stones being hurled at the equipment.

New switches and fuses have been installed in the near past.

Equipment overall are rusty and damp from leaks. These are mainly caused by environmental exposure and location near lake. On the contrary, transformer is in pretty good shape with no visible leaks.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
JN-1	1982	JN-2, BD-1	HI-2
JN-2	383	BD-2	JN-1

Substation Name: John S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					
Condition: 3 (Fair)			X		
Condition: 4 (Poor)	X	X		X	X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Vandalism, Close to arena				Close to neighbor

Kenilworth

Year Built: 1960

Address: 96 KENILWORTH AVENUE SOUTH, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

This indoor facility has a slite roof which is harder and more expensive to maintain.

Asbestos is found on the wall and has been patched to avoid exposure.

There is no spill containment in the base of the transformers and could be a possible environmental issue. The station is heavily loaded and has experienced high peaks during the summer months. The transformers are very close to the building which makes them harder to do maintenance work on them. However, they have been very reliable in the past with so major issues experienced. There are no safety issues based on exposure to the surroundings.

The Air Circuit Breakers (ACB) have been very reliable as usual and are also easily maintained. The electrical wiring for the station has been done in the last 10 years.

There is a manhole leading to the roadside in the basement and is an issue to be recognized in case the property is considered for resale.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
KE-1	1813	KE-6, SP-3, OT-6	KE-3, KE-4
KE-2	937	CP-1	
KE-3	1768	KE-1, KE-5	
KE-4	1579	KE-1, KE-5	
KE-5	600	BA-2	KE-3, KE-4
KE-6	1510	BA-4	KE-1

Substation Name: Kenilworth S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)		X		X	
Condition: 3 (Fair)			X		
Condition: 4 (Poor)					X
Condition: 5 (Critical)	X				
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Confined space, access to bay is difficult		Historic overloads		

Mohawk

Year Built: 1953

Address: 709 UPPER GAGE,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

New feeder wraps and duct seals have been installed on the transformers. Station service equipment has been rewired in the near past.

This premise houses 1 spare air circuit breaker and oil circuit breaker each. New batteries for circuit breakers have been installed recently.

The property is pretty big and will bring in a lot of revenue if sold off after Conversion. The substation is in pretty good overall condition will minor spill from conductors in the basement.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
MK-1	1831	MK-9	MK-9, EA-1
MK-2	1185	EA-2, MK-5, MK-6, MT-6	
MK-3	1656		MT-2, MT-3
MK-5	492		MK-2
MK-6	1118	EA-9	MK-2
MK-9	1125	MK-1, MT-3	MK-1
MK-10	2041	EA-3	
MK-11	2172	EA-1	

Substation Name: Mohawk S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)	X				
Condition: 2 (Good)		X		X	
Condition: 3 (Fair)					
Condition: 4 (Poor)			X		X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Easy access		Oil leak - managed	ACBs and OCBs. OCB contacts need replacing	Close to public

Mountain

Year Built: 1965

Address: 510 UPPER WENTWORTH, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

The facility has slite roof which is harder and more expensive to maintain.

Bus work was redone on the 13 kV side last 10 years but nothing has been done on the 4 kV side.

Station service electrical work has been done recently. Breaker panels have been redone. One spare air circuit breaker and oil circuit breaker is housed in this station. Batteries for the breakers have been recently installed.

Directional blocking switches have been kept open because of lack of investigation and reason as to why the station goes down when they are closed.

There are 3 power transformers in this station among which 2 are newer than the other. 2 spare transformers are also housed in the transformer bay. The older one has new feeder wraps.

The physical condition of the walls is very poor with signs asbestos. There is a lot of oil and water leak in the basement wall from conductors.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
MT-2	1342	MT-3, MK-3	
MT-3	1537	MK-3	MT-2, MK-9
MT-4	1757	MT-9, MT-10, MT-11	MT-5
MT-5	1399	MT-4, MT-6, MT-10	WL-9
MT-6	1547		MK-2, MT-5, MT-9, WL-2, WL-4
MT-9	1695	MT-6	MT-4
MT-10	1611	CE-10	MT-5, MT-11
MT-11		MT-10	MT-4

Substation Name: Mountain S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X	X			
Condition: 3 (Fair)			X	X	
Condition: 4 (Poor)					X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Large lot			ACBs and OCBs. OCB contacts need replacing	Close to public, no transformer bay, asbestos managed

Ottawa

Year Built: 1967

Address: 64 DALKEITH STREET,
HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

This station has a standard Air Circuit Breaker setup with relatively new metal-clad and equipments.

This station has been extremely reliable with no major failures. Three power-transformers are housed in the bay which were installed in the 1960s and are still in pretty good condition. There is also a slot open to house another power-transformer in the bay.

There have been no effects of theft or vandalism. The substation is very clean and physically in very sound condition.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
OT-1	595	OT-2	OT-8
OT-2	1087		OT-1
OT-3	1348	OT-4	KE-1, SP-1
OT-4	1709	CP-7	OT-3
OT-5	1102	OT-6	CP-5
OT-6	148		OT-5
OT-7	1267	SP-7	
OT-8	795	OT-1	

Substation Name: Ottawa S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)		X		X	
Condition: 3 (Fair)					X
Condition: 4 (Poor)	X		X		
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Access poor due to location		Some historical leaks and suspect repairs	ACBs	

Parkdale

Year Built: 1924

Address: 300 PARKDALE AVENUE NORTH, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

The transformers are in the parking lot and are a potential safety issue.

There is a combination of Air Circuit Breakers and Oil Circuit Breakers in this substation. The metal clad is relatively new. The electrical panels are old and might require attention in the future.

There are multiple 13 kV sources in this substation which improves the redundancy and reduces the risk associated to this substation. Overall, the station is pretty reliable and functionally stable.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
PA-3	858		CP-4
PA-4	1497	PA-7	
PA-5	1660	PA-10	BA-1, CP-1, PA-1
PA-6	448	PA-8	
PA-7	1382	PA-8	PA-4
PA-8	1501		PA-6, PA-7, PA-9, PA-11
PA-9	619	PA-8	CP-3
PA-10	1352	PA-5	
PA-11	641	PA-8	

Substation Name: Parkdale S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					
Condition: 3 (Fair)		X		X	
Condition: 4 (Poor)	X		X		X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Poor access, close to heavy traffic		Valve leak – managed, close to road	OCB contacts replaced	Oil spill directly to sewer

Spadina

Year Built: 1930

Address: 994 KING STREET EAST, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

A transformer had failed in the past exploding through glass windows. The glass windows on the transformer bay side has been shut will steel plates ever since. As precaution, a blast wall will be built soon to provide protective shield to protect the neighbors in case another explosion occurs. The transformer has not been replaced and the load was transferred over.

The bus cover and metal-clad was replaced around 20 years ago. New breaker batteries were installed in 2004.

The station has been generally very reliable with no recollection of major cable faults or breaker failure.

This station is used as a training facility for the underground splicing crew. There is a roadside man-hole from the basement of this substation. These are added considerations during Conversion.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
SP-1	1516	SP-5	OT-3
SP-2	1709	WT-9	SP-5
SP-3	1418	SP-4, SP-10	WT-10
SP-4	831	SP-6	SP-3
SP-5	1786	SP-1, SP-2	SP-9
SP-6	1986		KE-1, SP-4
SP-7	765		OT-7
SP-10	667		SP-3

Substation Name: Spadina S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)			X		
Condition: 3 (Fair)					X
Condition: 4 (Poor)	X	X		X	
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Due to age and design			T3 bus to be condemned, OCBs	

Stroud's Lane

Year Built: 1938

Address: 1225 MAIN STREET EAST,
HAMILTON

Street Names: MAIN & STROUD'S LANE

Facility: INDOOR S/S

Visual Assessment / Comments

No maintenance on the bus work has been conducted in the past. The low loading on the station dictates the good condition of the bus work.

Premise has a consistent foul odor and might be caused by a possible gas leak. This requires further investigation.

Fiber-wired junction point inside the station and requires consideration when the station will be decommissioned. Early relocation notification should be given to them while engineering is working on the Conversion.

There are 2 transformers in the substation and are in fairly good condition. The station is in good overall condition.

Dependency / Loading

Feeder	**Loading (kVA)**	**Backed Up By**	**Back-Up For**
ST-2	1325	ST-7	
ST-3	1364	ST-4	
ST-4	1112	WH-2	ST-3, WH-1
ST-6	1516	ST-7	AB-5
ST-7	1273		ST-2, ST-6

Substation Name: Stroud's Lane S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					X
Condition: 3 (Fair)	X		X		
Condition: 4 (Poor)		X		X	
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Flooding issues during rainfall			ACB's – CT issues	

Webster

Year Built: UNKNOWN

Address: 86 WEBSTER ROAD, STONEY CREEK

Facility: OUTDOOR S/S

Visual Assessment / Comments

This outdoor station has been identified as high risk condition.

The transformers are among the oldest in our system (e.g. built – 1952). The Oil Analysis results have identified the transformers to have been exposed to extremely high heat and have caused deterioration in the paper insulation. This might cause transformer to fail and cause major outage. Replacing the transformers will be costly and time consuming.

There are 3 13kv sources coming into the station and feeding the transformers. This might be an issue with three phase commercial customers in the case a transformer fails. The bushings styles installed in this station are hard to replace.

The single phase reclosers are very old and don't have any spares. These are also not easily available in the market to replace. This is another issue that has been identified. Replacement will also be time consuming and expensive.

There is however no theft or vandalism in this substation as seen in some other outdoor stations.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WB-1	479.5	WB-2	
WB-2	684	DH-3, GA-2	WB-1

Substation Name: Webster S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					
Condition: 3 (Fair)					
Condition: 4 (Poor)	X	X			
Condition: 5 (Critical)			X	X	X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Structure needs painting, becoming worse with housing growth		Overloaded 3 1ph TX, 2nd oldest in system, bad oil results	1 ph reclosers, lack of spare, flashed over in May 2007	Close to public, Close to Hwy 20

Wellington

Year Built: 1960

Address: 227 MOHAWK ROAD EAST, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

This facility is used as a storage / workshop for repairs on different equipment. This station has a huge amount of supplies, tools and gear which would require tremendous amount of relocation effort to an alternate facility where the work can be conducted. This is a severe consideration in the Conversion procedure.

The circuit breakers in this station are functionally problematic. Issues with the cell hardware and the relays have been evident in the past. The coils in the breakers burn up and require regular maintenance. The breakers deteriorate pretty fast while they are stagnated and freeze up.

This station is in overall good condition with no major failures in the recent past. There is a blast wall installed in the station to protect public safely in case of transformer explosion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WL-1	974	WL-8	
WL-2	1622	WL-9	
WL-3	868	WL-4	
WL-4	966	MT-6	WL-4
WL-5	1720	WL-11, WL-8	
WL-6	1474	WL-7, WL-9	EL-4
WL-8	1268	WL-10	WL-1, WL-5
WL-9	1442	MT-5	WL-2, WL-6
WL-10	773		EL-9, WL-8
WL-11	1699		WL-5

Substation Name: Wellington S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X	X			X
Condition: 3 (Fair)			X	X	
Condition: 4 (Poor)					
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason				GE – New bearing required on all ACBs	

Wentworth

Year Built: 1930

Address: 681 KING STREET EAST, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

The station is extremely warm inside. This is caused by the windows shutout with steel plates to avoid vandalism. There have been various incidents of copper ground wires being cut out and stolen from the transformers. This has been done by climbing over a school side fence that separates the transformer bay and the school premises. This is also a potentially hazardous location to transformer failure and might be considered for building a blast wall.

The station has been very reliable with fairly new installations and metal-clad. The basement is dirty with signs of leaks from conductors.

There is a high pressure water pipe going through the basement of the substation which is in very bad physical condition. If this pipe ruptures it will cause the station to flood and will cause major equipment failure and potentially hazardous situation. There is a fiber-wired hub in the substation. There is a manhole from the basement leading to the street. These are major considerations that need to be attended for safety and Conversion.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WT-1	1204	WT-11	WT-6
WT-2	1708	WT-11	
WT-3	1583		WT-4, WT-9
WT-4	1416	WT-3	
WT-5	1892	SP-3	
WT-6	1023	WT-1, WT-12	
WT-8	678		
WT-9	1057	SP-9, WT-3	SP-2
WT-10	992	HU-11	WT-12
WT-11	515		WT-1, WT-2
WT-12	631	WT-10	WT-6

Substation Name: Wentworth S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)				**X**	
Condition: 2 (Good)			X		
Condition: 3 (Fair)					
Condition: 4 (Poor)	X	X			
Condition: 5 (Critical)					X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Poor due to age and design			ACBs are new	No blast wall, day care beside, oil spill to sewer, asbestos present

Whitney

Year Built: 1963

Address: 252 WHITNEY AVENUE, HAMILTON

Facility: INDOOR S/S

Visual Assessment / Comments

This station has a similar indoor station setup to Stroud's Lane. The structure of the building is clean and stable.

Batteries of Circuit Breakers are nearing the end of life and will be changed soon.

The transformers are relatively new and in good condition. There have been no hardware issues in this station in the near past and functionally has been very stable.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WH-1	1545	ST-4, WH-4	
WH-2	1106	WH-6	ST-4
WH-3	1385	WH-4	
WH-4	644	WH-5	WH-1, WH-3
WH-5	1428	HA-1	WH-4, HA-1
WH-6	744		WH-2

Substation Name: Whitney S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)		X	X	X	
Condition: 3 (Fair)					X
Condition: 4 (Poor)	X				
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Access – heavy equipment difficult through front door			ACBs	

York

Year Built: UNKNOWN

Address: 230 YORK ROAD, DUNDAS

Facility: OUTDOOR S/S

Visual Assessment / Comments

Recloser oil is leaking. This most probably is caused by oil-overflow.

The station has been functionally very stable with no major hardware failure. There is less effects of vandalism and theft in this station compared to other stations because of the secluded location of the property.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
YK-1	448	YK-2, YK-2.1	
YK-2	795	YK-1.1	YK-1

Substation Name: York S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X	X	X		
Condition: 3 (Fair)					
Condition: 4 (Poor)				X	X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Some vandalism		No issues	Oil recloser	Top of escarpment, environmental issues

Grantham

Year Built: 1965

Address: 319 ½ GRANTHAM AVE.

Facility: INDOOR S/S

Visual Assessment / Comments

This station housed General Electric Circuit Breakers which have been problematic in the past. These are scheduled to be maintained next year.

The transformers are in pretty good functional and physical shape. The transformer T-2 is a bit noisy but is functionally stable. The transformer bay requires regular debris cleaning with is a maintenance issue that is troublesome.

There are new batteries for the station service transformer.

The station is in overall good condition.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
GRF1	3458	VEF3, GRF2	VEF3, GRF2
GRF2	2882	GRF1, GRF4	GRF1, GRF4
GRF4	2738	GRF2	

Substation Name: Grantham S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X	X			
Condition: 3 (Fair)					
Condition: 4 (Poor)			X	X	X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	No basement, cable pits		HV & LV terms exposed	G.E. – sticky bearings, Lack of available spares, some P&C issues	TXs close together, HV exposed terms

Taylor

Year Built:

Address: 100 CARLTON STREET

Facility: OUTDOOR S/S

Visual Assessment / Comments

The transformers in this station are the oldest in the system. The vibro acoustic test results show they are in okay condition. But the oil test results indicate that their insulation has experienced heavy degradation.

Automatic reclosers have been used to replace the breakers in this station. This has converted it to a potentially outdoor station, with the building having no functional use.

The transformer expulsion pipes point at each other and are thus a critical safety hazard in case of transformer failure. The oil from one transformer will be projected towards another one making it extremely dangerous. The outdoor structure housing the transformers is set up such that if one transformer fails, the other one has to be removed to replace the other one. This might cause long duration of downtime in case the issue arises. The complexity of the structure also makes it hard to maintain.

Overall, the station is very old and functionally risky. As mentioned above, major safety hazards are eminent in this station. The high voltage equipment is in easy access from the neighborhood. There are heavy signs of theft and vandalism in this station.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
TAF1	966	TAF2, TAF3	TAF2, TAF3
TAF2	966	TAF1, TAF3	TAF1, TAF3
TAF3	2204	TAF2, WEF2	TAF2, WEF2

Substation Name: Taylor S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)					
Condition: 3 (Fair)					
Condition: 4 (Poor)					
Condition: 5 (Critical)	X	X	X	X	X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Building wall needs work, access very difficult for TX replace		Oldest TXs in system, overheated, overloaded, bird nesting	Squirrel, all HV terms exposed, very old bus work	Poor public safety, close to fence, TX vent directed at neighbor’s garage

Vine

Year Built: 1959

Address: 95 VINE STREET

Facility: INDOOR S/S

Visual Assessment / Comments

Vibro Acoustic Tests haven't been done on the transformers because it is not possible to run the test on this type of body structure. There is asbestos on the cable wrappings. These transformers have open conductors on top and are a potential safety hazard.

The expulsion pipe of one transformer points to another so, in case of explosion, all the oil from one transformer will be projected towards the other. This is a severe safety concern and needs to be attended to while transformer conditions deteriorate.

Circuit Breakers have been identified as functionally stable in the maintenance procedure. These breakers do have a lot of corrosion on their body. New batteries for the station service transformer have been installed.

This station has experience multiple occasions of copper theft in the past.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
VEF1	1945	VEF5	VEF5
VEF3	1441	GRF1	
VEF4	2579	VEF5, WEF1	VEF5, WEF1
VEF5	1873	VEF1, VEF4	VEF1, VEF4

Substation Name: Vine S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X				
Condition: 3 (Fair)					
Condition: 4 (Poor)		X	X	X	X
Condition: 5 (Critical)					
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	No basement, Vandalism, Large lot		Overloaded heaviest in system, overheated, bird nests	Inside of cells and ACB surface, rust, No spares	Public safety risk close to sidewalk, copper theft

Welland

Year Built:

Address: 136 WELLAND AVE.

Facility: INDOOR S/S

Visual Assessment / Comments

The conductors on top of the transformers are bare and are a potential safety hazard because this property is easily accessible from the roof of the neighboring building. There aren't any blast walls installed in this station.

The transformers in this station are functionally good. The vibro acoustic tests haven't been conducted on T-3 because it is not possible to conduct the test of this type of transformer body structure. The thermography test results have indicated absence of hot spots, so, they are not identified as immediate threats.

There is an open 4 kV bus bar inside the station, which is also a major safety hazard. But this has been dealt with by installing a caution-fenced door to restrict exposure.

The air circuit breakers have maintenance scheduled for next month. They have in the past shown sticky contacts and deteriorate fast when stagnated.

Although this station is pretty good physical and function condition, it has major safety issues associated to it.

Dependency / Loading

Feeder	Loading (kVA)	Backed Up By	Back-Up For
WEF1	1239	WEF2, VEF4	WEF2, VEF4
WEF2	1441	WEF1, TAF3	WEF1, TAF3
WEF4	720	VEF5	VEF5

Substation Name: Welland S/S

Parameters	Facility		Power Transformer	Switchgear	Safety / Environmental
Condition (Excellent)	**Criteria:** No access issues, Building in very good condition and Minimal repairs required		**Criteria:** Relatively new or recently refurbished, no visible oil spill, loading < nameplate and Good historical test results	**Criteria:** Relatively new, parts readily available, Air Circuit Breaker, Low # of operations, Good maintenance history	**Criteria:** Oil spill containment in place, Neighbors not exposed, no exposure to pollutants and PCB / Asbestos not present
	Access	**Building Condition**			
Condition: 1 (Excellent)					
Condition: 2 (Good)	X				
Condition: 3 (Fair)				X	
Condition: 4 (Poor)		X			
Condition: 5 (Critical)			X		X
Condition (Critical)	**Criteria:** Very poor access, facility in very poor condition with major repairs required		**Criteria:** Very old, big oil spill visible, loading > nameplate and past test results show poor condition	**Criteria:** Very old breaker or recloser, replacement parts not available, high number of operations and bad maintenance record	**Criteria:** No Oil Spill containment, neighborhood exposed to high voltage equipment, heavy exposure to pollutants and PCB/Asbestos is present
Reason	Copper theft, graffiti, poor plumbing, exposed 4 kV bus in building		TX's poor shape, close to each other, HV LV terms exposed	Spares not available	Close neighbor, 406, Public close to HV term if on roof

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Horizon Utilities Corporation

Station Asset Condition Assessment Report 2010

Prepared By:
Networks
April 9, 2010

horizon UTILITIES Looking beyond...

Executive Summary

This report is a summary of Asset Condition Data gathered on Horizon Utilities Corporations 30 municipal substations. It includes analysis of the data as well as a strategic replacement plan for different asset types.

The Asset Condition Data was gathered and scored by Spyros Kapodistrias of Acumen Engineered Solutions International Inc. (AESI). He is considered a subject matter expert on electrical utility substations as he has over 25 years experience working as a substation engineer with Toronto Hydro Electric System. The condition assessments were based on predictive testing data on the substation equipment and a visual inspection.

The Asset Condition Assessment highlights the necessity for Horizon Utilties Corporation to invest in substation infrastructure to ensure it is decommissioned in line with the 4kV & 8 kV Renewal Plan.

The report highlights replacement strategies for Power Transformers, Circuit Breakers, Switchgear, and Other Substation Equipment. The replacement strategies consider replacement costs, life expectancy of both the existing and new product, station decommission dates, criticality to operation, and condition score.

Based on this report a total expenditure of approximately $4-6M in substations is required over the next 5 years for continuing operation of station assets until they are decommissioned.

Contents

1.0 Introduction

Horizon Utilities Corporation is the fourth largest municipally owned electricity distribution company in Ontario. It provides electricity and related utility services to over 231,000 residential and commercial customers in Hamilton and St. Catharines. The electricity distribution system voltage levels range from 4160 volts (4.16kV) to a maximum of 27600 volts (27.6kV).

Although the majority of the customer base in Hamilton and St. Catharines is served from the 13.8kV and the 27.6kV distribution voltage levels, approximately 82,000 customers are served from the 4.16kV and 8.32kV levels. These areas include 30 substations among which 26 are in Hamilton and 4 are in St. Catharines. More than 50% of these substations are greater then 50 years old and are nearing the end of life (EOL). This poses the threat of incurring unanticipated outages due to equipment failure and high capital expenditure levels. In addition, certain components have test results showing signs of stress and damage which increases the chance of failure.

In 2008 Horizon Utilities prepared a report to address the 4kV and 8kV system with an objective to renew/convert the assets to a higher voltage distribution supplied directly from the Transformer Stations. The elimination of 4kV will permit the removal of load from the affected 4k and 8kV substations and allow them to be decommissioned.

Until the 4kV and 8kV Renewal/Conversion Plan is completed, these stations are an integral part of the distribution system, and it is essential that they be maintained and refurbished or replaced before EOL is reached. It became evident in this assessment that our past maintenance of these stations has been appropriately planned and completed by our Stations Department. However, the results of this assessment report identify various station components that require replacement or refurbishment if we are to avoid future outages that would negatively impact our reliability indices. Certain components in our system, namely breakers and relays, require extensive time and attention by our stations staff. New technology such as vacuum circuit breakers and electronic relays are close to maintenance free, in addition the newer equipment will improve performance, and reliability.

There is no doubt that the future conversion of 4kV and the elimination of Horizons 4 kV infrastructure is inevitable, but the scope of work to accomplish this over the short term is beyond the financial and resource capabilities of Horizon Utilities. Voltage conversions tend to be expensive and technically challenging and it’s not unreasonable to expect them to be carried out as a multi-year program. Therefore it’s important to ensure that the existing 4kV and 8kV substations will remain reliable and functional until conversion allows them to be decommissioned.

2.0 Background

Horizon has a total of 31 substations in their distribution system and this report will present results of station assessments completed on 30 those stations (Halson SS decommissioned in the same year as the study). The assessment consisted of a site inspection by an experienced substation engineer with over 25 years of past experience with Toronto Hydro in their stations department. Site inspections were followed by interrogation of office records including past test reports and equipment history to provide an accurate assessment and ranking of key individual components within each of the eight (8) identified equipment types critical to the operation of a substation.

The distribution assets within a typical distribution station were grouped into asset classes. A weighting was assigned to each class based on their individual contributing impact on the company. Impacts on the company were based on the values that drive utilities and are supported by Horizon's Vision and Mission statement. They include safety, reliability, regulatory compliance, efficiency, financial and reputation. A weighting scale developed with AESI for each asset class was applied universally throughout the station assessment process.

Proper asset management strategy dictates that assets be rehabilitated or replaced before and as close as possible to the 'End of Life' (EOL) of the asset. The majority of 4kV and 8kV station assets range from 1950 to 1967 well past EOL, and are fully depreciated. The objective of this Asset Condition Assessment (ACA) is to provide a measure of health for each station as well as the individual components within it and to provide some indication of remaining life expectancy. The ACA process also strives to provide a measure of station health relative to other stations so that allocation of budget funding can be properly prioritized.

Horizon's 4kV and 8kV Renewal Plan which commenced in 2008 originally provided only a general station condition assessment of each substation. This report provides a detailed assessment of each class of equipment within a substation. This will enable Horizon to develop a substation renewal plan that considers the health index of each station and allow them to coordinate replacement with scheduled decommission. In addition, this assessment will be a substation database which can be used by substation and engineering services for planning and analysis.

As previously mentioned, the aging substations and 4kV and 8kV infrastructure requires voltage conversion to either 13.8KV or 27.6KV. Based on the results of the ACA, the 2008 4kV and 8kV Renewal Plan was revised to include the new substation assessments. The 30 substations were grouped into 7 distribution neighbourhoods and ranked from worst (1) to best (7) as seen below:

1) St. Catharines (Worst)

2) Hamilton Downtown

3) Hamilton West

4) Hamilton Mountain

5) Hamilton East

6) Stoney Creek

7) Dundas (Best)

The 2009 renewal plan and this report outline both a conversion and replacement plan, these two plans have been aligned to ensure that the pace of conversion and replacement is cost-effect and efficient. This report will not only outline the ACA results but also recommend asset replacement strategies for poor substation equipment.

3.0 Methodology

To perform an ACA on Horizons' stations AESI broke down each station into (8) different major equipment types and each equipment type was further broken down into individual components or component test results. The overall station health index considers ratings of each individual component within each of the 8 equipment types in a substation and each rating is based on pre-established rating criteria which provides consistency between station assessments.

The 8 equipment types and their associated components are as follows:

1) Transformers (19 components rated)
2) Breakers (10 components rated)
3) Switchgear (7 components rated)
4) Site & Civil (17 components rated)
5) P & C (7 components rated)
6) Station Service (9 components rated)
7) Reclosers (8 components rated)
8) Bus, Switches & Structure (9 components rated)

For a complete assessment of a station such as Eastmount substation with 3 station transformers and 2 switchgear line-ups, a total of 123 components are individually assessed. Drilling down and assessing multiple individual components within each equipment class strives to ensure the best possible accuracy of the station rating, otherwise known as the Station Health Index. AESI performed an inspection at each station and analyzed historical testing data when performing its ACA. Each component is assigned a rating based on either pre-established criteria (IEEE, CSA, ESA) or AESI developed ranking. Each component is rated as critical, fair or good condition. Appendix A: Asset Condition Assessment Criteria shows the rating criteria established for each component within each of the 8 equipment types and the weighting assigned to each individual component as prepared by AESI. The assessment is based on a visual inspection and test results where available. Each rating criteria started with a general base as follows:

Poor
Asset has less than 5 years of remaining life and needs more extensive detailed inspection and/or testing to determine what is required in terms of replacement or rehabilitation. It's critical that the detailed inspection and follow up plan be initiated immediately.

Fair
Assets rated fair should not require major component replacement within 5 years and usually only routine and scheduled maintenance. A new ACA after 5 years should be conducted to monitor its condition and determine the extent of component replacement required.

Good
Assets rated good have an expected EOL in excess of 15 years and usually only routine and scheduled maintenance.

The scope of this ACA includes all 4kV and 8 kV stations in Horizon's service territory. This report will attempt to quantify the health of the asset based on visual and predictive test results (where applicable), and provide details on availability of spare parts, technical obsolescence, age, performance of the asset, and ongoing maintenance costs.

Major Assets Assessed in this Report

Asset Class	Type	Units Assessed By AESI
Power Transformer (approx $250K / unit)	27.6 kV / 4.16 kV	7
	27.6 kV / 8 kV	4
	13.8 kV / 4.16 kV	64
	Subtotal:	**75**
Breakers (approx $30K / unit)	Oil	52
	Air	240
	Subtotal:	**293**
Switchgear (approx $2.5M / unit)	15 kV Bus	11
	4kV Bus	31
	Subtotal:	**42**
Site and Structures (approx $1.5 M - $2.5M / structure)	27.6kV / 8.3 kV	9
	13.8kV / 4.16 kV	1
	Subtotal:	**10**

4.0 Assessment Results for Equipment Types

An overall station condition health listing can be found in Appendix B: Overall Station Health, it is broken up into both indoor and outdoor stations and a combined station listing. The overall condition score is a weighting sum of all assets according to the 8 equipment types listed in the Methodology section.

4.1 Overall Station Weighting

AESI and Horizon staff agreed that the 8 equipment types vary in criticality to station performance for both outdoor and indoor substations. Below is the overall equipment weighting for both substation types.

Equipment Type	Indoor Substation Weighting	Outdoor Substation Weighting
Transformer	25%	30%
Breaker	20%	0%
Recloser	0%	15%
Switchgear	20%	0%
Protection and Control	20%	15%
Station Service	5%	5%
Site and Civil	10%	10%
Bus, Switches, and Structure	0%	25%
Total	100%	100%

4.2 Power Transformer Assessment

Transformers are considered one of the most important and critical equipment types in a substation. Depending on the configuration of a substation and the number of power transformers in the line up, a transformer failure can result in part or all of the substation being removed from service. In addition, transformers are expensive with a 5MVA unit estimated at approximately $250K and in excess of 12 months lead time for delivery (not including specification preparation and requisitioning lead times). Repair costs usually involve de-tanking the unit and rewinding the core which costs for a similarly sized unit approximately $160K with delivery times of approximately 4 months. Consequently, the transformer is an extremely important equipment type and it’s important that this component has an accurate health assessment as it represents the highest weighting in a stations health score.

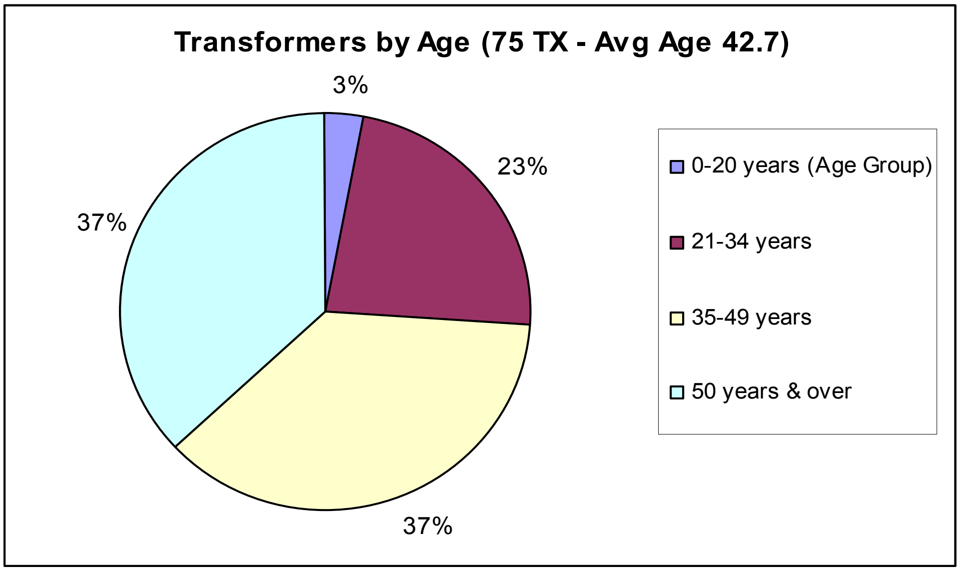
The major factors of transformer health are:

1) Oil Leaks (Score x3)
2) Oil Gas Content (Score x3)
3) Dissolved Gas Analysis (DGA) (Score x5)
4) Vibro-Acoustic Testing (Score x2)

The criteria above AESI and Horizon staff agreed with the most critical scores when assessing transformer health.

Although age is not a sole indicator of transformer EOL, it is important to understand the age demographics of our transformer population. Industry guidelines accept that power transformers reach EOL in 40 to 60 years; this can be used as one factor for replacement criteria. The table and corresponding graph below help to provide a profile of the current transformer population at Horizon.

Transformer Age Group (years)	Percentage of Population	Number of Transformers
0-20 years (Age Group)	3%	2
21-34 years	23%	17
35-49 years	37%	28
50 years & over	37%	28



The age demographics clearly indicate that Horizon has an aging group of power transformers. Of the total population of transformers 74% or 56 units are at or near end of life. To replace all these units would cost $14B and refurbishment would cost $8.96M.

In 10 years, if Horizon continues to follow the 4kV & 8kV Renewal plan there will be a total of 37 transformers in the system. From that total group, 17 transformers will be past the 60 year EOL mark with another 7 between 50-60 years of age. This supports 5.1 Power Transformer Replacement to rewind/repair transformers over the next 4 years for approximately $1.28M-$1.5M.

Transformer health is based on a combination of visual inspections and results from predictive testing. The Transformer Age Profile Chart indicates that over 50% of transformers or nearing or past end of life. The transformer health index can be found in Appendix C: Transformer Health Index, the median score is 85% indicating that the majority of transformers are well maintained.

However, Diagnostic Gas Analysis (DGA) tests performed have the highest weighting in terms of transformer health evaluation. As previously mentioned age is not the sole indicator of condition, DGA provides a more detailed evaluation of the health of a transformer, as it directly corresponds to insulation deterioration. The table below outlines DGA results for each station transformer that has at least 10% loss of life due to high DGA content. Furan content above 100ppb represents a 10% loss in life and above 250ppb as a 25% loss of life. Based on the table below all stations have a 10% loss of life with 24 transformers with a loss of life of 25% or greater. It should be noted 7 of the top 10 transformers with the highest DGA result are being decommissioned in the next 2 years.

Station	Transformer ID #	Year Built	DGA Test Results (Furan content -ppb)	DGA Impact
Welland	T3-TX087	1955	3397	Failure within 1-3 years
Hughson	T2-TX027	1961	3357	
Taylor	T2-TX081	1950	2954	
Webster	T1W-TX056	1952	2420	Failure within 1-5 years
Taylor	T1A-TX078	1953	2385	
Webster	T1B-TX057	1952	2172	
Webster	T1R-TX055	1952	2032	
Taylor	T1B-TX079	1953	1364	
Grantham	T1-TX076	1964	955	25% loss of life
Taylor	T1C-TX080	1953	915	
Vine	T1-TX083	1954	709	
Welland	T1-TX085	1955	567	
Eastmount	T1-TX015	1958	479	
Welland	T2-TX086	1955	447	
York	T1-TX068	1959	442	
Vine	T2-TX084	1962	400	
Hughson	T4-TX029	1961	390	
Eastmount	T3-TX017	1955	363	
Hughson	T3-TX028	1960	363	
Caroline	T2-TX007	1957	353	
Ottawa	T1-TX041	1966	305	
Kenilworth	T1-TX032	1967	296	
Halson	T2-TX024	1953	282	
Eastmount	T2-TX016	1955	259	
Mohawk	T3-TX036	1961	204	10% loss of life
Elmwood	T2-TX020	1958	189	
Grantham	T2-TX077	1958	178	
Kenilworth	T2-TX033	1967	177	
Mohawk	T2-TX035	1957	175	
Taylor	T3-TX082	1962	169	
Wellington	T3-TX060	1959	166	
Galbraith	T1-TX022	1959	143	
Elmwood	T1-TX019	1959	119	

To summarize the condition of Horizon’s power transformers the ACA shows a well maintained, however aged and stressed asset group. It is necessary to implement some renewal projects to ensure that the stations will last until their assigned decommission date.

4.3 Circuit Breakers

Circuit breakers are an integral part of substation operations, and it is necessary that they are working properly to protect the station transformer as well quickly to interrupt a fault. Horizon’s has 3 types of circuit breakers: Oil (18%), Air Magnetic (70%), and Magneblast (12%). Appendix D: Circuit Breaker Analysis contains various circuit breaker analysis tables based on the ACA.

When assessing circuit breakers AESI and Horizon staff agreed that no one evaluation criteria was critical when assessing the condition and health of the asset.

Oil breakers are generally not used in the industry any longer and are being replaced by newer technology that uses vacuum or SF6 as the interrupting medium. Due to obsolescence of oil breaker technology spare parts are becoming more difficult to source and often require custom machining or fabrication to provide replacement parts. In addition to the extensive maintenance demands of oil breaker technology, the vintage units typically in Horizon’s stations have slow operating speeds compared to new technology and this creates added stress on cables, transformers and other ancillary equipment under fault conditions when speed of fault clearing is crucial to limit equipment stress and damage.

4.4 Switchgear & Structures

Horizon has both indoor and outdoor substations in its service territory of the 31 substations, 9 are outdoor and the remaining 22 are indoor. Of the 41 switchgear line ups 88% are nearing or at end of life. The median score for indoor stations was 64%, compared to outdoor stations with 86%. Appendix E: Switchgear Analysis contains various switchgear analysis tables based on the ACA. The reason for the poor results from indoor switchgear is based on the fact the bus has never been off potential since it has been put in service, therefore the maintenance that can be performed is limited. Outdoor stations on the other hand don’t have enclosed switchgear and therefore don’t have as many issues.

AESI and Horizon staff agreed that for indoor switchgear the impact of ‘partial discharge’ (Score x3) had the greatest impact in determining switchgear condition. However, for outdoor switchgear no single evaluation criteria were deemed to be significant to impact the condition or health.

In addition, old switchgear was not designed to the more stringent arc fault requirements commonly specified in today’s switchgear standards and hence, the importance to clear high current bus faults quickly and reliably becomes extremely important in consideration of personnel safety if in the vicinity of switchgear should a bus fault occur.

The recent bus fault at Central Station is a good example of switchgear not designed to arc proof standards. At Central SS a three phase bus fault in the order of 10 kA RMS cause sufficient explosive forces to dislodge the rear panel from the switchgear and shear the bolt heads securing it. An additional safety concern relates to most of the magnetic air blast breakers which use asbestos lined arc chutes and require special maintenance procedures to limit staff exposure to air borne asbestos particles.

4.5 Other Substation Equipment

AESI reviewed a variety of other substation equipment; this section will just highlight the major criteria for each of the remaining 8 types evaluated.

Site & Civil

- Security (Score x 2)
- Fire (Score x2)

P & C

- Relay (Score x2)
- RTU (Score x2)
- Performance results of Relays (Score x2)

Station Service

- Oil Spill Environmental Impact (Score x2)

Reclosers (8 components rated)

- No Critical Components

5.0 Substation Asset Replacement Strategies

A Substation Asset Replacement Strategy was developed using asset management principles and the results of the ACA which is the basis of this report. The cost and life expectancy of new components i.e. breakers, power transformers, versus the expected decommission date of a station and its asset score was consider during replacement strategies. A replacement strategy was developed for 4 classes: Power transformers, circuit breakers, Switchgear & Structure, and Other Substation Equipment. This report described the replacement strategy developed and endorsed by both Substation Services and the Network group of Horizon Utilities.

5.1 Power Transformer Replacement

As stated previous in the power transformer section 56 (74%) of all transformers are nearing or at end of life, and all transformers also have a 10% loss of life based on DGA. This combined with the fact that not all stations are standardized in the Horizon system means significant investment must be made for power transformers.

Horizon Utilities has 2 in-service (on potential) spares, and 6 deployable (off potential) spare transformers. In 2010 the 6 deployable spares will be tested to determine if they are still operable. Based on these results the recommendation will be to either rewind 2 of the deployable spares and then make them in-service spares, or, to purchase a new spare transformer. The new transformer would be designed with multiple exhaust\throat configurations so it can serve as a spare to multiple stations. In subsequent years 2011-2013, the budget will remain such that for this period 2 transformers are rewound or 1 transformer purchased on an annual basis.

5.2 Circuit Breaker Replacement

Circuit breaker replacement do to the types of breakers was broken up into two categories: oil and air. Need for replacement was based on oil have higher maintenance costs, and violent failures here would cause significant damage to surrounding infrastructure. Based on this information the following action plan was developed:

A total of 6 stations have active oil breakers, in ten years only 3 stations will still have active oil breakers. Based on the cost to custom engineer new breakers to fit the existing switchgear, Substation Services was approached with some renewal options. The oil breakers when removed from service would be examined, and the best condition ones would be used to replace some of the remaining in service breakers as well acting as spares. This plan mitigates the risk while addressing both cost and renewal projects.

Examining the 10 worst air breakers, within 10 years only 1 of the stations will be in service. In discussion with Substation Services, a breaker replacement strategy was developed. Breakers have a replacement cost of roughly $25,000 per breaker. In 2009 Horizon is spending $750K to replace the breakers at 2 stations, in the next 3 years Horizon will replace an additional 41 breakers at 3 stations for a total cost of $1,025K. This upgrades the breakers as the stations which will be in-service the longest and has a low breaker score on the ACA.

5.3 Switchgear & Structure Replacement

Switchgear is very expensive to replace as was discovered in 2009 when a plan to replace the Wellington switchgear was approved. The breakers were in far worst condition than the switchgear and consequently the allotted 2009 Wellington switchgear replacement budget funds were spent on breaker replacements at Wellington and Cope stations to achieve the maximum cost benefit. However, when considering a switchgear asset replacement strategy based on the average life expectancy of switchgear 35-40 years it was decided with Substation Services that Parkdale would receive new switchgear as it is one of the last stations to be decommissioned. Bartonville switchgear was suggested to be replaced, but this requires further investigation as performing this operation would have both benefits and disadvantages. The estimated cost of a new switchgear and installation is estimated to be $1.5-2M based on quotes from 2009 on other switchgear replacements. In addition, there are other factors related to the PILC feeder egress cables which can escalate the switchgear replacement cost, sometimes by a factor equal to the cost of the switchgear replacement.

5.4 Other Substation Equipment Replacement

Other substation equipment such as remote terminal units (RTU's), relays, substation transformers, batteries and station services were handled on a case by case basis.

RTU's are now becoming more and more obsolete as digital relays are being built to handle their functions. As both relays and RTU's are part of a smart grid infrastructure investment, it is anticipated that the majority of funding will come from smart grid initiatives to replace these components. Should smart grid incentives not replace ageing electromechanical relays then they will be replaced based on the ACA results and remaining station life.

Smart grid initiatives are also expected to fund improvements to the cybersecurity related assets within our stations to limit or restrict malicious access to our systems. We anticipate some funding will be required to install communication gateways and security walls to provide the necessary protection against cyber attacks, an every increasing risk, especially once we begin to replace some of the existing electromechanical relays and RTUs with more advanced technology.

Substation transformers and batteries are already on a replacement schedule prepared by Substation services. It is the recommendation of this report to continue the program as scheduled. Station Services and various infrastructure issues have been identified by the ACA and Substation Services staff, it is recommended that all health and safety matters be completed immediately and general investments in station upkeep be maintained in reference to cost and decommission date.

Appendix A: Asset Condition Assessment Criteria

Asset Condition Assessment - Transformers

Methodology

Asset		Evaluation & Rating Criteria			
Item	Transformer - Visual Inspection	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Tank/ Conservator (x1 weighting)	extensive and heavy rust spots throughout; extensive bare paint spots; dents or other visible damage; oil leaks from gaskets/tank/conservator	minimum rust or abrasions; no visible damage dents; reasonably clean looking	no visible rust or damaged; clean and paint in good condition	
2	Bushings (x1 weighting)	leaking oil; visible cracks, dents or other damage; discoloration indicating overheating on termination points; accumulation of corrosion, dirt, grime	no oil leaking; no damage or discoloration visible; minimum dust/dirt visible	no oil leaking or other damages and clean looking	
3	Tap Changer (x1 weighting)	heavy wear and tear on internal and external moving parts based on maintenance records; external control circuit devices (motor, relays, switches, wiring) covered with dirt/grime/oil etc or appear damaged; poor oil test results based on maintenance records.	minor (acceptable) wear and tear of moving parts; external control circuit devices appear reasonably clean and not damaged; oil tests acceptable based on records	no wear and tear on devices and no known deficiencies based on maintenance records	
4	Cooling Radiators (x1 weighting)	extensive and heavy rust spots throughout; extensive bare paint spots; dents abrasions or other visible damage; oil leaks from cracks or rusty spots; cooling fins or tubes blocked with debris, weeds, leaves or other objects; paint flaking throughout	minimum light rust; minor dents and abrasions; no oil leaks; minor paint flaking	no visible rust or damage; paint intact; no oil leaks	
5	Cooling Fans (x1 weighting)	removed from service and not replaced; installed but not in working condition; damaged blades and/or protective safety shield; covered with heavy oil, dirt/grime.	in working condition; minor dents; minimum dirt and oil coverage;	in working condition; no obvious damage or dirt	
6	Oil Leaks **(x3 weighting)**	evidence of extensive/heavy oil leaks around transformer area or switch yard; visible oil leaks from transformer tank, cooling tubes, circuit brk's, cable termination points (potheads etc), PILC cables	some presence of old oil leaks around transformer and switchyard; no obvious fresh oil leaks from any station equipment	station equipment appear free from any oil leaks	
7	Gauges (x1 weighting)	missing or not in working condition; damaged or heavily rusted; cannot be read due to dirt/grime build-up or fade-out plate markings	in working condition; cracked glass; minimum dirt/grime or moisture inside gauge	in working condition; appears clean, undamaged and rust free	
8	Pressure Relief Vents - Explosion Vents (x1 weighting)	extensive/heavy rust cover; warps, dents, abrasions or other damage; blocked or covered with debris or other material/equipment	no obstructions; no visible damage; minimum rust and abrasions	free of rust damage and obstructions	
9	Silica Gel (x1 weighting)	missing silica (not refilled); colour all pink and requiring replacement	silica in service with partial pink in colour	silica colour is all blue	

10	Transformer Pad/ Foundation (x1 weighting)	visible deterioration of concrete and exposed reinforced steel - major rust, cracks, large pieces of concrete fallen from pads or footings; tilted or warped transformer pads due to foundation abnormalities (i.e. broken, rusted or recessed footings, other damage); recessed earth around footings needs to be filled with gravel	minimum deterioration of concrete and reinforced steel - minor rust, cracks, small pieces of concrete fallen from pads or footings; no tilted or warped transformer pads; minimum recession of earth around footings	no deterioration of concrete and/or reinforced steel - no rust or major cracks; no tilted or warped transformer pads; no recession of earth around footings	
	Transformer Test Results				
11	Oil Color (x1 weighting)	below manufacturer's recommended lower limit (<0.5) - Results based on test report	at or just above manufacturer's recommended low limits (at or just above 0.5) - mostly clear little sediment	within manufacturer's recommended limits (0.5 to 8.0) - clear no sediment	
12	Oil Dielectric Strength (x1 weighting)	below manufacturer's recommended lower limit (<30kV) - Results based on test report	at or just above manufacturer's recommended lower limit (at or just above 30kV)	well above manufacturer's recommended lower limit (>30kV)	
13	Oil PCB Content (x1 weighting)	above 50ppm	50ppm	well below 50ppm	
14	Oil Gas Content **(x3 weighting)**	Total of all combustible gases above 1900 ppm (as per test report results) - ANSI/ IEEE Guide C57.104-1991	Total of all combustible gases 700 ppm to 1900 ppm (as per test report results)	Total of all combustible gases less than 700 ppm (as per test report results)	
15	DGA - Insulating Paper Degradation **(x5 weighting)**	amount of furanic compounds generated during testing is above 250 ppb total furans (250 ppb of total furans corresponds roughly to 25% loss of life)	amount of furanic compounda generated during testing is between 101 ppb to 250 ppb total furans	amount of furanic compounda generated during testing is between 0 ppb to 100 ppb total furans (100 ppb of total furans corresponds roughly to 10% loss of life)	
16	Power Factor Test (x1 weighting)	above recommended upper limit (>0.5%)	at or just below recommended upper limit (at or just below 0.5%)	well below recommended upper limit (<0.5%)	
17	Vibro Accoustic Testing - (transf'r testing for core and winding integrity) **(x2 weighting)**	meassured coefficient below recommended values (<0.8) - as per test results;(indication of loose core and/or winding)	meassured coefficient within recommended values (0.8 - 0.9) - as per test results	meassured coefficient high (0.9 - 1.0) - as per test results	
18	Transformer Age (x1 weighting)	above 35 years of age	20 to 35 years of age	1 to 19 years of age	
19	Transformer Performance Record (x1 weighting)	frequent failures; frequent and/or lengthy maintenance or repair work required; unreliable performance; very high sound levels; poor test results (loss of life based on insulation degradation test results above - item #15	normal reliability perfomance, maintenance and repairs	high reliability performance and low maintenance	

Asset Condition Assessment Methodology- Circuit Breakers

Asset		Evaluation & Rating Criteria			
Item	CB Tank & Chassis Insp'n	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Tank (x1 weighting)	extensive and heavy rust spots throughout; extensive bare paint spots; dents or other visible damage; oil leaks from gaskets/tank etc.	minimum rust or abrasions; no visible damage dents; reasonably clean looking	no visible rust or damaged; clean and paint in good condition	
2	Oil Condition (x1 weighting)		*oil is generally in good condition as it is replaced during every regular CB maintenance*		
3	Primary contacts (Cluster Condition) (x1 weighting)	visible signs of wear & tear; rough surfaces and signs of arcing damage; visible dirt, grime oil etc.; poor contact alignment; loose or sluggish finger movement	minimum contact wear & good alignment; no signs of arcing damage or other alignment problems; reasonably clean	no contact wear & good alignment; no signs of arcing damage; clean contacts	
4	Secondary Contacts (Pallet Switches) (x1 weighting)	visible signs of wear & tear; rough surfaces and signs of arcing damage; visible dirt, grime oil etc.; poor contact alignment; loose or sluggish finger movement; contact resistance above recommended values	minimum contact wear & good alignment; no signs of arcing damage or alignment problems; contact resistance within recommended values; reasonably clean	no contact wear & good alignment; no signs of arcing damage; contact resistance well below recommended values	
	CB Interrupting & Contact Condition				
5	Arc Chute (x1 weighting)	asbestos material present; visible of heavy dirt/grime; visible cracks and other damage; alignment problems; history of frequent maintenance	free of asbestos material; no visible cracks or other damage; reasonably clean - free of dirt, oil, grime or other substances	free of asbestos; free of any damage and in clean condition	
6	Contact Resistance (x1 weighting)	contact resistance high (above recommended values) - *based on measured values from maintenance records*	contact resistance reasonably within recommended values	contact resistance low (well below recommended values)	
	CB Operarting & Control Mechanism				
7	Minimum Trip Voltage Test of Trip Coil (x1 weighting)	minimum trip voltage of trip coil high (above recommended value)	minimum trip voltage at recommended value	minimum trip voltage below at or below recommended value	
8	# of CB Operations (x1 weighting)	above average # of operations (typically above 1000)	around average # of operations (typically 500 to 1000)	below average # of operations (typically 500 or less)	
9	Circuit Breaker Age (x1 weighting)	above 35 years of age	20 to 35 years of age	1 to 19 years of age	
10	CB Performance Record (x1 weighting)	frequent failures; frequent and/or lengthy maintenance or repair work required; unreliable performance	normal reliability performance, maintenance and repairs	high reliability performance and low maintenance	

Asset Condition Assessment Methodology- Reclosers

Asset		Evaluation & Rating Criteria			
Item	Reclosure Inspection	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Tank (x1 weighting)	extensive and heavy rust spots throughout; extensive bare paint spots; dents or other visible damage; oil leaks from gaskets/tank etc.	minimum rust or abrasions; no visible damage dents; reasonably clean looking	no visible rust or damaged; clean and paint in good condition	
2	Insulators (x1 weighting)	visible cracks, chipping, dirt, grime, bird droppings etc.; evidence of discoloration on conductor terminals likely due to overheating; heavy corrosion build-up on terminals and running on surface of insulator	no visible damage on insulators or evidence of discoloration at terminal points; minimum corrosion at terminal points and dirt build-up on insulator surfaces	no visible damage, discoloration, corrosion or dirt build-up on insulators	
3	Counter - Function & Reading (x1 weighting)	not installed, not working; broken, damaged; cannot read due to dirt/grime or orientation; higher than normal operations since last scheduled maintenance	working properly; some dirt/grime; normal number of operations since last scheduled maintenance	working properly and in good condition; less than normal number of operations since last scheduled maintenance	
4	Manual Open/Close Operation (x1 weighting)	recloser fails to open or close manually during testing - typically, mechanical problems with gears, linkages or other moving parts	recloser Opens and Closes manually but appears to be sluggish	recloser Opens and Closes manually as expected	
5	Reclosure Sequence Test (x1 weighting)	reclosure fails to operate within the define parameters (curves) for *Fast Operations, Slow Operations and Number of Operations to Lockout*	reclosure operates within the define parameters (curves) for *Fast Operations, Slow Operations and Number of Operations to Lockout* but requires many adjustments	reclosure operates within the define parameters	
6	Meggar Test (x1 weighting)	meggar reading below acceptable values (indicating damaged insulation, tracking, poor oil quality etc.)	meggar reading at acceptable values	meggar reading well above acceptable values	
7	Reclosure Age (x1 weighting)	above 35 years of age	20 to 35 years of age	1 to 19 years of age	
8	Reclosure Performance Record (x1 weighting)	frequent failures; frequent and/or lengthy maintenance or repair work required; unreliable performance	normal reliability performance, maintenance and repairs	high reliability performance and low maintenance	

Asset Condition Assessment Methodology- Switchgear

Asset		Evaluation & Rating Criteria			
Item	Switchgear Inspection	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Bus & Insulators (x1 weighting)	visible deterioration/damage to bus insulation and/or bus support insulators; evidence of partial discharge damage, - tracking, burnt marks, holes; accumulation of dirt/grime; discoloration due to overheating	no visible insulation deterioration, discoloration or other damage; minimum accumulation of dirt/grime	no visible insulation deterioration or other damage; no accumulation of dirt/grime	
2	Metal Clad (x1 weighting)	extensive and heavy rust spots throughout; extensive bare paint spots; dents/openings or other visible damage; evidence of debris, rodent droppings, and/or rain water leakage; electrical clearances (i.e. HV phase to ground) inadequate; tight working spaces; panel doors, hinges, locking hasps or other mechanisms out of alignment or not working properly etc.; shutters in CB compartment missing or not working properly	minimum rust, dents abrasions etc. but in working condition; interphase barriers and/or CB shutters in place as required; electrical clearances within standards	no rust and in good working condition; electrical clearances within standards and adequate working spaces	
3	Instrument Transformers (x1 weighting)	evidence of deteriorated or burnt insulation on CT's and/or PT's; visible cracks, dents or other physical damage; accumulation of dirt/grime; poor resistance or turns ratio readings	evidence of aged insulation but equipment in working condition	no evidence of any damage and in good working condition	
4	Cable Terminations (x1 weighting)	oil or compound substance leaking from potheads/ terminators; build up of dirt/grime, bird droppings etc. on terminal insulators; visible cracks/dents or chipping; discoloration indicating overheating on termination points; heavy corrosion; no interphase insulation barriers	no oil leaks; minimum dirt or corrosion build up on terminal insulators; no physical damage or discoloration on termination points; interphase insulation barriers installed	no corrosion build up or physical damage or discoloration on termination points; insulation HV phase barriers installed	
5	Partial Discharge **(x3 weighting)**	PD emissions above recommended standards - based on measured values from maintenance records; evidence of insulation deterioration or other damage - tracking, burnt marks, holes, cracks etc. to affected equipment	PD emissions within recommended standards - based on measured values from maintenance records; no evidence of insulation damage	PD emissions well below recommended standards - based on measured values from maintenance records; no evidence of insulation damage	
6	Switchgear Age (x1 weighting)	above 35 years of age	20 to 35 years of age	1 to 19 years of age	
7	Switchgear Performance Record (x1 weighting)	frequent failures; frequent and/or lengthy maintenance or repair work required; unreliable performance	normal reliability performance, maintenance and repairs	high reliability performance and low maintenance	

Asset Condition Assessment Methodology- Protection & Control

Asset		Evaluation & Rating Criteria			
Item	P&C Inspection	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Relays **(x2 weighting)**	evidence of electrical/ mechanical damage - dents, abrasions, broken covers/cases; dusty/dirty/burnt contacts; discoloration of relay terminals/contacts due to overheating; applied relay settings drift outside acceptable tolerances (above 10% P/U & above 15% of set time - based on relay test sheets); above 35 years of age	no major mechanical damage - minor abrasions on covers/cases; no discoloration or burnt relay terminals/contacts; applied relay settings within acceptable tolerances (based on tests); 20 to 35 years old	no visual mechanical/electrical damage; applied relay settings within acceptable tolerances; 1 to 19 years of age	
2	Panel Inst's, Controls, Wiring & CT Links (x1 weighting)	evidence of electrical/ mechanical damage on various instruments - dents, abrasions, broken covers/cases, bent auxiliary relay contacts, loose terminals (CT links etc), broken or worn out insulation of control wiring, discoloration or burnt wiring terminals; accumulation of dust/dirt on terminals/contacts	min. evidence of electrical/ mechanical damage on var. instruments and control wiring; minimum accumulation of dust/dirt on term./contacts; no loose terminals (CT links etc), discoloration or burnt wiring terminals; no broken or worn out insulation of control wiring, discoloration or burnt wiring terminals	no evidence of electrical/ mechanical damage on var. instruments and control wiring; all instruments and wiring appear clean and tidy	
3	RTU **(x2 weighting)**	evidence of mechanical or electrical damage on the unit - i.e. dents, abrasions, rust, loose terminals/ contacts, worn out insulation of control wiring, discoloration or burnt wiring terminals; accumulation of dust/dirt on terminals/contacts; frequent breakdowns; over 20 years of age	in good working condition; minor evidence of deterioration or other mechanical damage; no worn out insulation of control wiring, discoloration or burnt wiring terminals; exposed to minimum dust/dirt; 10 - 20 years of age	in good working condition; unit is relatively new; no evidence of deterioration or other mechanical damage; 1 - 9 years of age	
4	Batteries (x1 weighting)	evidence of mechanical/ chemical or electrical damage - i.e. crack/dented cells, broken terminal posts, electrolyte leakage, corrosion build up; accumulation of dirt/grime; loose connections; discoloration of terminals; cells internal resistance higher than manufacturer's recommended tolerance values; cell voltage outside recommended tolerance values; specific gravity reading (for Wet Cells) outside recommended tolerances; battery supply voltage near low limit; battery is past the scheduled 8 year replacement cycle	no evidence of mechanical/ chemical or electrical damage; minimum dirt accumulation; cell voltages and internal resistance within recommended tolerance values; battery supply voltage within normal range; battery age range is between 5 - 8 years	no evidence of mechanical/ chemical or electrical damage; battery is relatively new; no dirt accumulation; cell voltages and internal resistance within recommended tolerance values; battery supply voltage within normal range; battery age range is between 1-4 years	
5	Charger (x1 weighting)	evidence of mechanical or electrical damage on the unit - i.e. dents, abrasions, rust, loose terminals or contacts, broken indication instruments or other control devices, worn out insulation of control wiring, discoloration or burnt wiring terminals; accumulation of dust/dirt on terminals/contacts; poor voltage regulation; frequent breakdowns/repairs; over 25 years of age	no evidence of mechanical or electrical damage on the unit; minor accumulation of dust/dirt; voltage regulation normal; no known breakdowns/repairs; 10 - 24 years of age	no evidence of mechanical or electrical damage on the unit; charger is relatively new, dirt free and regulates within normal range; 1 - 9 years of age	

Item	P&C Inspection	Poor (0)	Fair (1)	Good (2)	ACA Score
6	Control Wiring Drawings (x1 weighting)	control wiring drawings not available in the substation and/or in main office; drawings are old, ripped, faded and difficult to read; drawings have not been updated to show changes;	control wiring drawings are available in substation/main office but not readily accessible; drawings are relatively current and in good condition; some organizational improvements required	control wiring drawings are available in substation and/or main office and easily accessible; drawings are current, in good condition and updated as required	
7	P&C (Relays) Performance Record **(x2 weighting)**	frequent failures; frequent and/or lengthy maintenance or repair work required; applied relay settings drift outside acceptable tolerances (based on tests and relay sheet settings); unreliable performance	normal reliability performance, maintenance and repairs	high reliability performance and low maintenance	

Asset Condition Assessment Methodology- Station Service

Asset		Evaluation & Rating Criteria			
Item	Station Service Equipment	Poor (0)	Fair (1)	Good (2)	ACA Score
1	S.S. Transformer Condition (x1 weighting)	extensive and heavy rust spots throughout; extensive bare paint spots; dents or other visible damage; oil leaks visible; some exposed live parts (i.e. terminals, windings) enclosed or caged in for isolation; located in wet/damp area; oil filled and located inside bldg; above 35 years of age	minimum rust or abrasions; no visible damage dents; no exposed live parts; reasonably clean looking; 20 to 35 years of age	no visible rust or damaged; clean and paint in good condition; relatively new transformer (1 to 19 years)	
2	S.S. Main Switchboard (Contactor) (x1 weighting)	extensive and heavy rust spots throughout; dents/openings or other visible damage; electrical components are old and unreliable; electrical clearances (i.e. HV phase to ground) inadequate; tight working spaces; panel doors, hinges, locking hasps or other mechanisms out of alignment or not working properly etc.; above 35 years of age	minimum rust, dents abrasions etc. but in working condition; 20 to 35 years of age	no rust and in good working condition; electrical clearances within standards and adequate working spaces; 1 to 19 years old	
3	Oil Spill Containment (x1 weighting)	no spill containment system installed for oil transformers; spill containment appears inadequate for size of oil transformer; spill containment in poor condition - i.e. heavy rust, cracks, holes or other physical damage	spill containment system installed and appears adequate for size of oil transformer; system appears in relatively good condition - i.e. minor rust and other physical damage	spill containment system recently installed and in good condition; no evidence of rust or damage	
4	Oil Spill Environmental Impact **(x2 weighting)**	accidental oil spill in station with no oil containment system: station soil and ground water contamination, oil contamination of city roads, sewers, parks, ravines, rivers, public property and buildings etc.; Note: the impact to the environment is much much greater if the oil is contaminated with PCB's above standard acceptable levels (50ppm). However with any oil spills environmental impact consequences would be high clean up costs and a bad public image	accidental oil spill in station with oil containment system in reasonably good operating condition and ample capacity to contain a spill; station is relatively away from public parks, rivers, populated areas, city sewers	accidental oil spill in station with new oil containment system in good operating condition and ample capacity to contain a spill; station is away from public parks, rivers, populated areas, city sewers	
5	Barrier Controls (x1 weighting)	control barriers to safely protect personnel/public from energized equipment inadequate, improperly secured or not installed; traffic barriers to protect equipment and personnel from moving vehicles inadequate or not installed; fire barriers to minimize the spread of fire damage between equipment inadequate or not installed; barriers or containers to isolate hazardous or combustible material inadequate or not installed; control barriers damaged, worn out, old/rusty and require replacement	all necessary control barriers to safely protect personnel, public and station equipment installed but may require some repairs/ maintenance or replacement	all necessary control barriers to safely protect personnel, public and station equipment installed and in good working condition	
6	Fusing & Panels (x1 weighting)	improper size fusing; fuses damaged, dirty or bypassed; electrical panels appear old, rusty or damaged; missing covers, exposed energized parts (fuses, terminals, wiring);	fusing and panels appear old but maintained in good working condition; no exposed energized parts and no visible damage	fusing and panels are new and in good working condition; no exposed energized parts and no visible damage	

Item	Station Service Equipment	Poor (0)	Fair (1)	Good (2)	ACA Score
7	AC Drawings (x1 weighting)	control wiring drawings not available in the substation and/or in main office; drawings are old, ripped, faded and difficult to read; drawings have not been updated to show changes;	control wiring drawings are available in substation/main office but not readily accessible; drawings are relatively current and in good condition; some organizational improvements required	control wiring drawings are available in substation and/or main office and easily accessible; drawings are current, in good condition and updated as required	
8	PCB Content in SS Transformer Oil (x1 weighting)	above 50ppm	50ppm	well below 50ppm	
9	S.S. Transformer & Main Switchboard Performance Record (x1 weighting)	frequent failures; frequent and/or lengthy maintenance or repair work required; unreliable performance; very high sound levels	normal reliability performance, maintenance and repairs	high reliability performance and low maintenance	

Asset Condition Assessment Methodology- Site & Civil

Asset		Evaluation & Rating Criteria			
Item	Site/Civil Visual Insp'n	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Building Structure (x1 weighting)	major building deterioration or defects - i.e. cracked or broken bldg. foundation, concrete, brick, walls, floors, roofs, doors, windows; heavy rusted steel beams in bldg, rusted windows, doors, roof etc.; tilted or warped structures; evidence of a leaking roof or water running into basement; evidence of birds or rodents coming inside bldg from holes and opening	no major building deterioration or defects - i.e. minor cracks on parts of bldg structure, foundation, walls, floors, doors, windows; minimum steel rust on beams windows, doors, roof etc.; no tilted or warped structures; no evidence of a leaking roof or water in basement; bldg is generally clean and in good condition	no building deterioration or defects - i.e. building structure is fairly new, clean dry and in good condition	
2	Fence & Gates (x1 weighting)	major damages/defects on fences and gates - i.e. heavy rust, fences are broken, ripped, have holes or openings, warped, tilted posts, gates not closing properly; height of fences or gates do not meet standard requirements (too low); fence or gates not grounded or do not meet proper grounding requirements; fences too close to energized conductors/ equipment (infringe within safe limits of approach)	minimum defects and/or rust on fences and gates - i.e. no broken or ripped fences/gates, no holes or openings, warping or tilting of posts and gates; gates close properly; fences and gates meet standard requirements for height, grounding and safe limits of approach from energized conductors/ equipment	no defects on fences and gates; some minor rusty spots; fence and gates meet grounding requirements and safe limits of approach	
3	Signage (x1 weighting)	existing signs are old, rusted, damaged, worn out and difficult to read; some signs have been removed or fallen off; insufficient signs posted; not all circuits or equipment have been properly stencilled or identified; some signs hidden and must be relocated to a more conspicuous location	existing signs are old but readable with minor wear and tear; all signs appear to be in place; additional signs may be of benefit to personnel or public (i.e. improve operations or awareness to safety	existing signs are in good condition and posted in place as required	
4	Grounding (x1 weighting)	no evidence of station ground rods, ground grid or ground mats; fences and gates not grounded; equipment and steel structures not grounded; ground rods or conductors/connectors heavily corroded or severed; ground grid resistance high (from tests on record)	station ground rods, ground grid or ground mats installed; fences, gates, steel structures and equipment grounded; minimum corrosion on ground rods and conductors/connectors; no evidence of severed ground conductors; ground grid resistance within acceptable limits (from tests on record)	station ground rods, ground grid or ground mats installed and appear in good operating condition; fences, gates, steel structures and other equipment, grounded; ground resistance low (from tests on record)	
5	Security **(x2 weighting)**	damaged or broken fences, gates, doors, windows, padlocks, hasps, locks; station equipment easily accessible to intruders (low fence or openings); defective or inadequate yard lighting, tree branches encroaching energized equipment; access to station not monitored	some minor defects on fences, gates, doors, windows etc. but in working condition; all locks, padlocks, hasps working properly; yard lighting may need some improvement;	no defects on fences, gates, doors, windows and locks in good working condition; yard lighting adequate and working; station access monitored remotely	
6	Fire **(x2 weighting)**	insufficient or no smoke detectors inside building; no portable fire extinguishers in station; flammable material, (rugs, paint containers, liquids, chemicals etc.) are kept in loose open spaces; tree branches, dry leaves and other debris materials near energized equipment; no fire alarm system installed	smoke detectors and portable fire extinguishers installed but improvements may be required; most flammable material stored in containers or cabinets; fire alarm system installed	smoke detectors and portable fire extinguishers installed as required; all flammable material stored in containers or cabinets; fire alarm system installed and monitored remotely	

Item	Station Service Equipment (x1 weighting)	Poor (0)	Fair (1)	Good (2)	ACA Score
7	Outside Access to Equipment (x1 weighting)	unable or very difficult to access or service equipment due to absence of road/ driveway or steep grade; insufficient clearances or violation of safe limits of approach due to tree branches, telephone wires or other;	equipment are accessible for service with sufficient clearances and minimum degree of difficulty; violation to safe limits of approach not anticipated	equipment are accessible for service with sufficient clearances; violation to safe limits of approach not anticipated	
8	Emergency Egress from Building (x1 weighting)	no panic hardware on fire exit doors; insufficient number of fire exit doors from building or switchgear/transformer enclosure; no emergency lighting battery pack system in place; no illuminated exit signs above doors; equipment or other debris materials blocking exit doors	sufficient fire exit doors equipped with panic hardware installed; emergency lighting battery pack system and illuminated exit signs may require some improvements; no equipment or other debris materials blocking exit doors	sufficient fire exit doors equipped with panic hardware installed; emergency lighting battery pack system and illuminated exit signs as required; no equipment or other debris materials blocking exit doors	
9	Basement Drainage (x1 weighting)	no drains or sump pump in basement; evidence of water running into basement	drains installed but no sump pump installed in basement	drains and sump pump installed and in good working condition	
10	Bldg Utilities (Heat, Electrical, Plumbing) (x1 weighting)	no heating, lighting , running water, hand wash or toilets facilities installed;	heating, lighting and running water installed but need improvements or upgrades	heating, lighting, running water, hand wash and toilets facilities installed and in good working condition	
11	Gravel Condition in Switch Yard (x1 weighting)	gravel thickness below recommended standards; gravel driven and pressed into earth; many bare earth spots visible; uneven gravel cover requires leveling	gravel thickness appears within recommended standards; no bare earth spots visible; some uneven gravel cover requires leveling	gravel thickness meets recommended standards; no bare earth spots or uneven gravel cover visible	
12	Driveway Condition (x1 weighting)	tarmac (asphalt/gravel) covered with large cracks, deep potholes or truck marks; requires leveling and/or additional gravel	tarmac (asphalt/gravel) covered with some minor cracks, potholes or truck marks; may require leveling and/or additional gravel	tarmac (asphalt/gravel) in good condition; no repairs or additional gravel required	
13	Animal / Pest Issues (x1 weighting)	evidence of rodents, raccoons or birds nesting inside building or on top of outdoor equipment and structures	no evidence of rodents, raccoons or birds nesting inside building; some evidence of nesting on top of outdoor equipment and structures	no evidence of rodents, raccoons or birds nesting inside building or on top of outdoor equipment and structures	
14	Weed & Vegetation Control (x1 weighting)	evidence of heavy weeds & vegetation growth in switch yard area and climbing around equipment and structures; tree branches and nearby plantation intrude into switch yard equipment	evidence of some weeds & vegetation growth in switch yard area but not climbing around equipment and structures	no evidence of weeds & vegetation growth in switch yard area	
15	Switch Yard Lighting (x1 weighting)	no yard lighting available; yard lighting inadequate or not in working condition	yard lighting available and in working condition; yard lighting may require some improvements	yard lighting adequate and in good working condition	
16	Building's Age (x1 weighting)	above 50 years of age	35 to 50 years of age	1 to 34 years of age	
17	Building's Performance Record (x1 weighting)	many defects and/or deficiencies; frequent maintenance and repairs required; does not meet current building code material & construction standards	normal level of deficiencies, maintenance and repairs required	no deficiencies and below normal levels of maintenance and repairs required	

Asset Condition Assessment Methodology- Bus Switches & Structures

Asset		Evaluation & Rating Criteria			
Item	Component Visual Insp'n	Poor (0)	Fair (1)	Good (2)	ACA Score
1	Air Breaker Switches (x1 weighting)	extensive/deep rust spots on the switch and/or operating handle; visible deformations or cracks on frame, line/arcing blade, insulators; poor blade alignment, loose or sluggish operation of switch blades or operating mechanism; visible signs of wear & tear on switch blades, arcing chutes and operating mechanism; signs of arcing damage on blades; visible dirt, grime, corrosion on insulators; discoloration from overheating on blades or terminals; high contact resistance (from test reports); above 25 years of age	minimum light rust spots or damage on the switch and/or operating handle; switch and operating handle in relatively good operating condition; minimum dirt on insulators or corrosion on the switch blades or terminals; contact resistance within tolerance values (from test reports); 15 to 25 years of age	no rust spots or damage on the switch and/or operating handle; switch and operating handle fairly new and/or in good operating condition; contact resistance low well within tolerance values (from test reports); 1 to 14 years old	
2	Load Interrupter Switches (x1 weighting)	extensive/deep rust spots on the LIS and/or operating handle; visible cracks or other defects on frame or insulators; poor switch blade alignment, loose or sluggish operation of switch blades or operating spring mechanism; visible signs of wear & tear on blades, arc chutes or operating mechanism; signs of arcing damage on blades; visible dirt, grime, corrosion on insulators or discoloration from overheating on blades or terminals; high contact resistance (from test reports); above 25 years of age	minimum light rust spots or damage on the switch and/or operating mechanism; switch and operating mechanism in relatively good operating condition; minimum dirt on insulators or corrosion on the switch blades or terminals; contact resistance within tolerance values (from test reports); 15 to 25 years of age	no rust spots or damage on the switch and/or operating mechanism; switch and operating mechanism fairly new and/or in good operating condition; contact resistance low well within tolerance values (from test reports); 1 to 14 years old	
3	Motor Operators for Switches (x1 weighting)	extensive/deep rust spots on the motor operating device and/or operating handle; various other visible defects; sluggish operation of the motor or operating mechanism; visible dirt, grime, corrosion or discoloration from overheating on motor; above 25 years of age	minimum rust spots or visible damage on the motor operating device and/or operating handle; motor operation is normal; presence of dirt is minimum; 15 to 25 years of age	no rust spots or visible damage on the motor operating device and/or operating handle; motor is fairly new and operation is normal; presence of dirt is minimum; 1 to 14 years old	
4	Line Openers (x1 weighting)	extensive/deep rust spots on the switch and/or operating handle; visible cracks or other defects on frame or insulators; poor blade alignment, loose or sluggish operation of switch blades or operating mechanism; visible signs of wear & tear on switch blades and operating mechanism; visible dirt, grime, corrosion on insulators; discoloration from overheating on blades or terminals; high contact resistance (from test reports); above 25 years of age	minimum light rust spots or damage on the switch and/or operating handle; switch and operating handle in relatively good operating condition; minimum dirt on insulators or corrosion on the switch blades or terminals; contact resistance within tolerance values (from test reports); 15 to 25 years of age	no rust spots or damage on the switch and/or operating handle; switch and operating handle fairly new and/or in good operating condition; contact resistance low well within tolerance values (from test reports); 1 to 14 years old	
5	Line Structure Foundation (x1 weighting)	visible deterioration of concrete and exposed reinforced steel - major rust, cracks, large pieces of concrete fallen from pads or footings; tilted or warped line structures due to foundation abnormalities (i.e. broken, rusted or recessed footings, other damage); steel and conductor/ cable support structure damaged or heavily rusted; recessed earth around footings needs to be filled with gravel	minimum deterioration of concrete and reinforced steel - minor rust, cracks, small pieces of concrete fallen from pads or footings; no tilted or warped line structures; minimum recession of earth around footings	no deterioration of concrete and/or reinforced steel - no rust or major cracks; no tilted or warped line structures; no recession of earth around footings	

Item	Station Service Equipment	Poor (0)	Fair (1)	Good (2)	ACA Score
6	Bus & Conductors (x1 weighting)	HV exposed bus/conductors infringe (violate) safe limits of approach - i.e. too close to ground points such as fences building walls/windows, trees, personnel etc.; heavy conductor corrosion or deterioration visible; evidence of conductor discoloration from overheating; build up of dirt, grime or bird droppings	HV exposed bus/conductors within safe limits of approach; minimum conductor corrosion or deterioration visible; no evidence of conductor discoloration from overheating; minimum build up of dirt, grime or bird droppings	HV exposed bus/conductors within safe limits of approach; no conductor corrosion, deterioration or discoloration visible; no build up of dirt, grime or bird droppings	
7	Cable Terminators / Potheads (x1 weighting)	oil or compound substance leaking from potheads; build up of dirt/grime, bird droppings etc. on terminal insulators; visible cracks/dents or chipping; discoloration indicating overheating on termination points; heavy corrosion; no interphase insulation barriers	no oil leaks; minimum dirt or corrosion build up on terminal insulators; no physical damage or discoloration on termination points; interphase insulation barriers installed	no corrosion build up or physical damage or discoloration on termination points; insulation phase barriers installed	
8	Insulators (x1 weighting)	visible cracks, chipping, dirt, grime, bird droppings etc.; evidence of discoloration on conductor terminals likely due to overheating; heavy corrosion build-up on terminals and running on surface of insulator	no visible damage on insulators or evidence of discoloration at terminal points; minimum corrosion at terminal points and dirt build-up on insulator surfaces	no visible damage, discoloration, corrosion or dirt build-up on insulators	
9	Arrestors (x1 weighting)	visible cracks, chipping, dirt, grime, bird droppings etc.; heavy corrosion build-up on terminals and running on surface of insulator	no visible damage; minimum dirt and/or corrosion build-up	no visible damage, dirt or corrosion build-up	

Appendix B: Overall Station Health

All Stations	Substation Score		Outdoor	Substation Score
Baldwin	85%		Baldwin	85%
John	85%		John	85%
Galbraith	84%		Galbraith	84%
York	82%		York	82%
Deerhurst	76%		Deerhurst	76%
Wentworth	75%		Dewitt	75%
Dewitt	75%		Taylor	53%
Hughson	71%		Webster	52%
Ottawa	66%		Halson	48%
Elmwood	65%			
Mountain	64%		**Indoor**	**Substation Score**
Spadina	63%		Wentworth	75%
Wellington	63%		Dewitt	75%
Central	62%		Hughson	71%
Cope	61%		Ottawa	66%
Whitney	61%		Elmwood	65%
Kenilworth	60%		Mountain	64%
Mohawk	60%		Spadina	63%
Bartonville	58%		Wellington	63%
Stroud's Lane	58%		Central	62%
Grantham	57%		Cope	61%
Eastmount	57%		Whitney	61%
Parkdale	56%		Kenilworth	60%
Caroline	55%		Mohawk	60%
Aberdeen	54%		Bartonville	58%
Vine	54%		Stroud's Lane	58%
Welland	54%		Grantham	57%
Highland	53%		Eastmount	57%
Taylor	53%		Parkdale	56%
Webster	52%		Caroline	55%
Halson	48%		Aberdeen	54%
			Vine	54%
			Welland	54%
			Highland	53%

Appendix C: Transformer Health Index

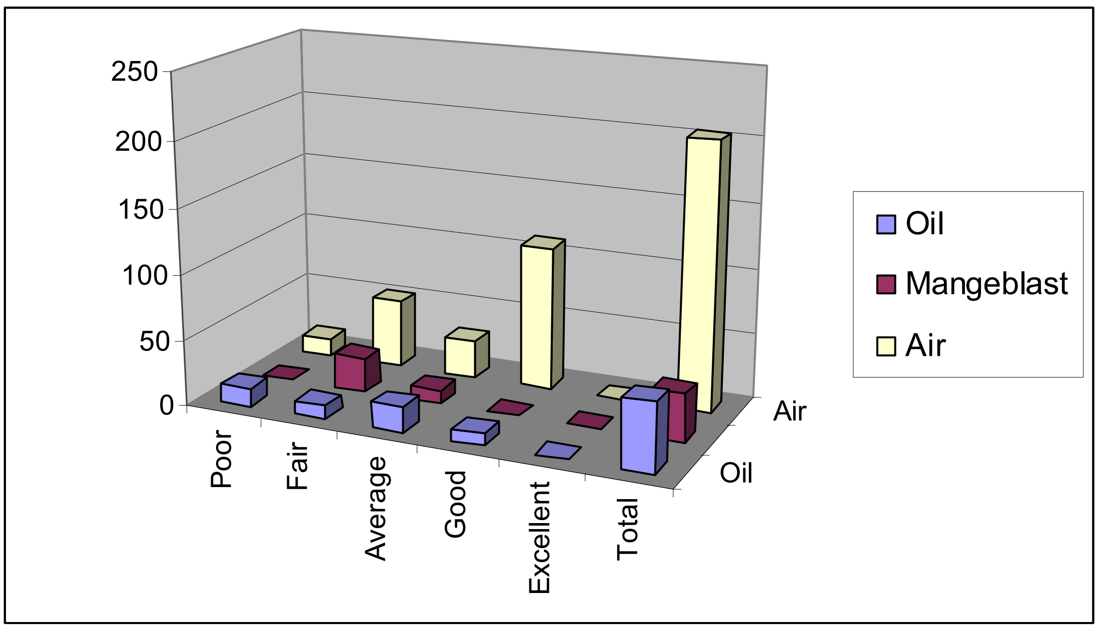
Substations	Transformers				
	T1	T2	T3	T4	Av. Tx. Score
Baldwin	98%				98%
John	87%				87%
Galbraith	78%				78%
York	89%				89%
Deerhurst	88%				88%
Wentworth	93%	98%	98%		96%
Dewitt	85%				85%
Hughson	96%	75%	77%	77%	81%
Ottawa	71%	93%	79%		81%
Elmwood	84%	84%	93%		87%
Mountain	96%	84%	81%		87%
Spadina	89%	89%			89%
Wellington	94%	86%	80%	89%	87%
Central	98%	93%			96%
Cope	87%	91%	89%		89%
Whitney	93%	95%			94%
Kenilworth	73%	82%			78%
Mohawk	90%	77%	79%		82%
Bartonville	91%	92%			91%
Stroud's Lane	89%	89%			89%
Grantham	70%	73%			71%
Eastmount	71%	66%	73%		70%
Parkdale	98%	98%	94%		97%
Caroline	91%	55%			73%
Aberdeen	91%	91%			91%
Vine	60%	64%			62%
Welland	63%	67%	54%		61%
Highland	96%				96%
Taylor	T1A = 34%, T1B = 34%, T1C = 41%	50%	79%		54%
Webster	T1R=38%, T1W=34%, T1B=32%				35%
Halson	87%	42%			64%

Appendix D: Circuit Breaker Analysis

CB Age Group(years)	Percentage of Population	Number of Circuit Breakers
0-20 years (Age Group)	1%	4
21-34 years	16%	50
35-49 years	43%	133
50 + years	39%	122

Type of CB	# of Breakers	% of Total
Oil	52	18%
Magneblast	36	12%
Air	204	70%
Total	292	100%

Rating	Oil	Air	Magneblast	Percentage of Total
Poor	14	13	0	9%
Fair	10	52	26	30%
Average	19	29	10	20%
Good	9	110	0	41%
Excellent	0	0	0	0%
Total	52	204	36	100%



Appendix E: Switchgear Analysis

Switchgear Rating (KV)	Number of Switchgear	Percentage of Total
4kV - (31 Switchgears)	29	73%
15kV - (11 Switchgears)	11	27%
Total	40	100%

Switchgear	Swgr-1	Swgr-2	Swgr-3	Swgr-4
Hughson	81%			
Wentworth	79%			
Galbraith	78%			
Eastmount	67%	67%		
Wellington	64%			
Welland	64%	64%		
Vine	64%			
Mountain	64%	64%	64%	
Grantham	64%	64%		
Elmwood	64%			
Central	64%	64%	64%	64%
Aberdeen	57%			
Mohawk	44%	61%	63%	
Ottawa	56%			
Kenilworth	56%			
Cope	56%			
Bartonville	44%	61%		
Spadina	78%	33%	33%	
Parkdale	39%	50%	39%	50%
Caroline	50%	29%		
Whitney	38%			
Highland	30%			
Stroud's Lane	17%			

Outdoor Substations	Bus Sw's & Struct's
Galbraith	100%
Dewitt	100%
Deerhurst	100%
Halson	92%
John	86%
York	83%
Baldwin	83%
Webster	67%
Taylor	60%

Appendix F: Station Asset Condition Assessment Presentation completed by AESI

Horizon Utilities

Asset Condition Assessment Study for Stations

July 6, 2009

Prepared and Presented by Spyros Kapodistrias (AESI Consulting)

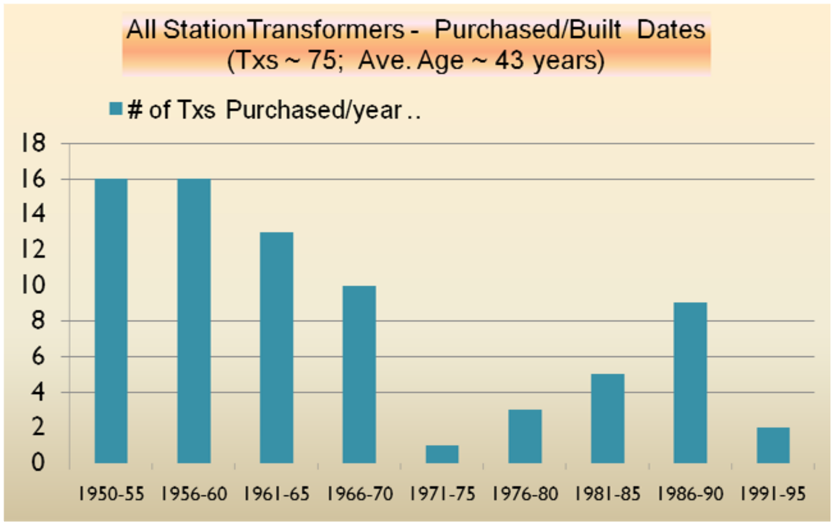
Station Transformers - Age

Substation Transformers: ~ 75

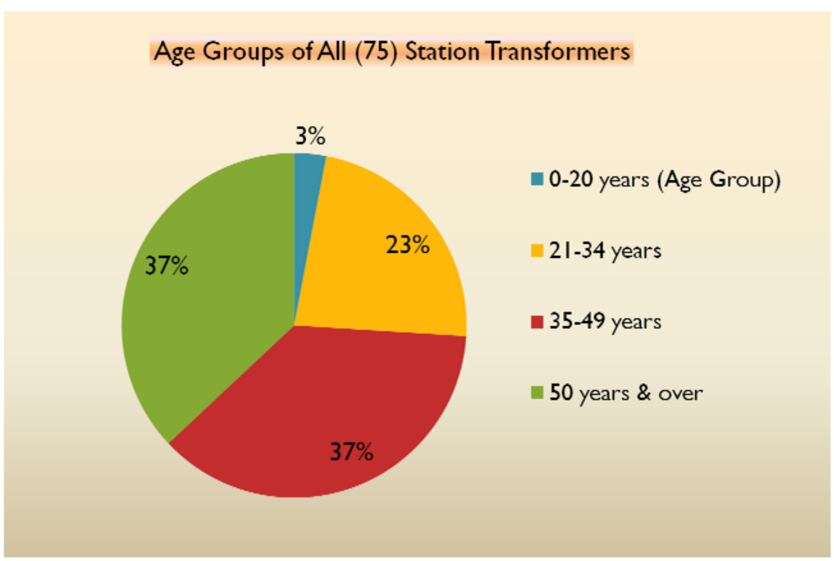
Average Age: ~ 42.6 years

- 37% are 50 years of age and over
- 72% are 40 years of age and over
- 73% are 35 years of age and over
- 25% are under 35 years of age

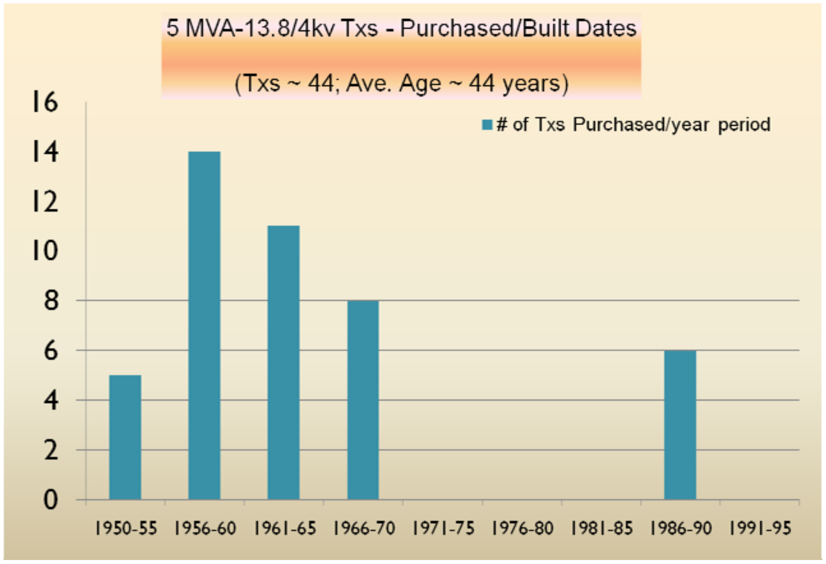
Station Txs – Distribution of Built Dates



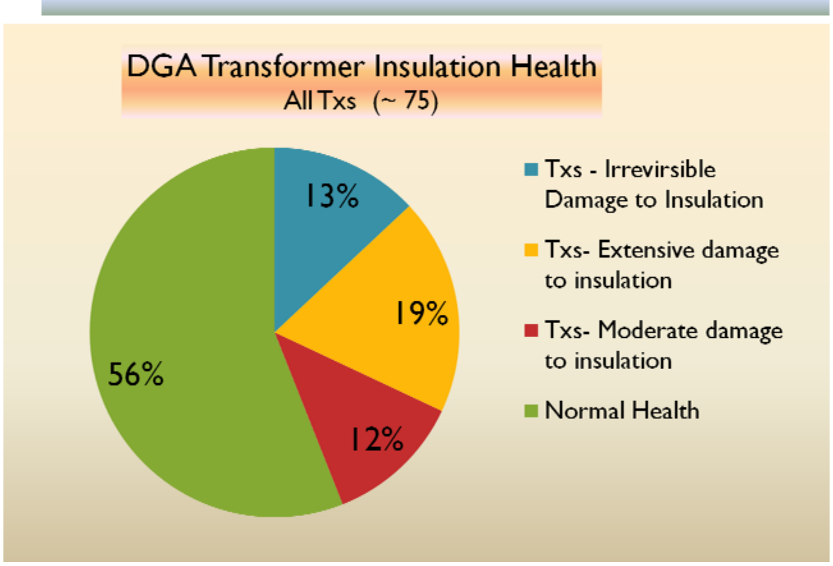
Station Transformers – Age Groups



5 MVA-13.8/4kV - Txs in Stations



Transformer Insulation Health



DGA Tx Health - Interpretation

- All substation power transformers have undergone DGA (Diagnostic Gas Analysis) tests - 33 of approx. 75 transformers had poor results
- Transformer oil is tested in ppb for Furan content . The higher the number found the greater the insulation degradation and transformer ageing
- Typically, 100 ppb of total furans corresponds to enough paper breakdown to be roughly equivalent to a 10% loss of life and 250 ppb of total furans corresponds roughly to a 25% loss of life

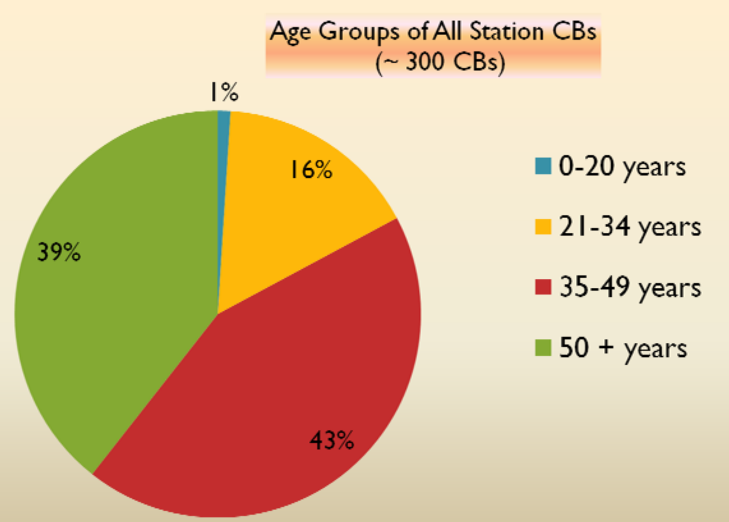
DGA Tx Health - Interpretation

- 0 to 100 ppb Furan content in transformer oil represents normal aging
- 101 to 250 ppb represents probable accelerated ageing (or moderate insulation deterioration)
- 251 ppb and up represents significant accelerated ageing (or extensive insulation deterioration)
- Levels above 1000 ppb is considered to be the start of the danger zone and indicate severe irevirsible damage to the solid insulation

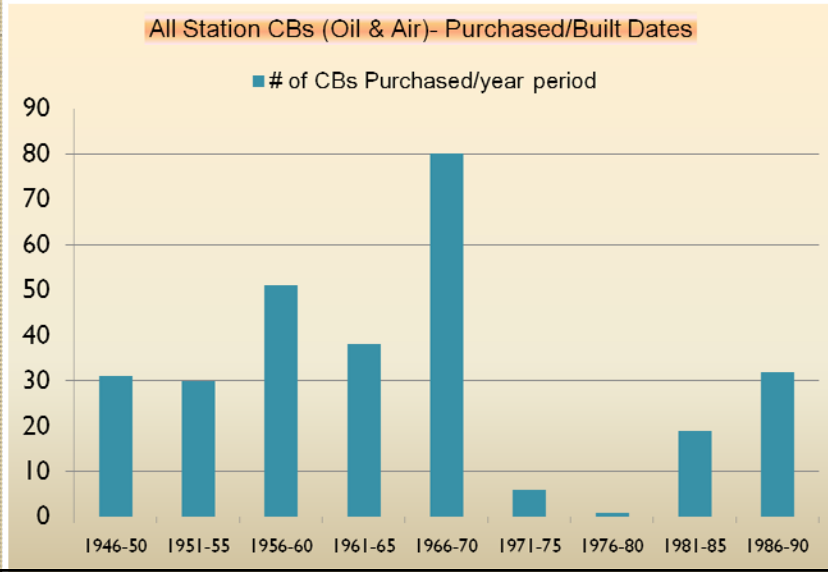
DGA Tx Health - Interpretation

- Levels above 1000 ppb is considered to be the start of the danger zone and indicate severe irevirsible damage to the solid insulation
- reclaiming or other oil maintenance procedures are not typically recommended where the total furan content exceeds 1000 ppb
- 1000 to 1500 ppb, the range where transformers typically begin to fail
- 2500 ppb total furans and above, replacement of transformer is highly recommended

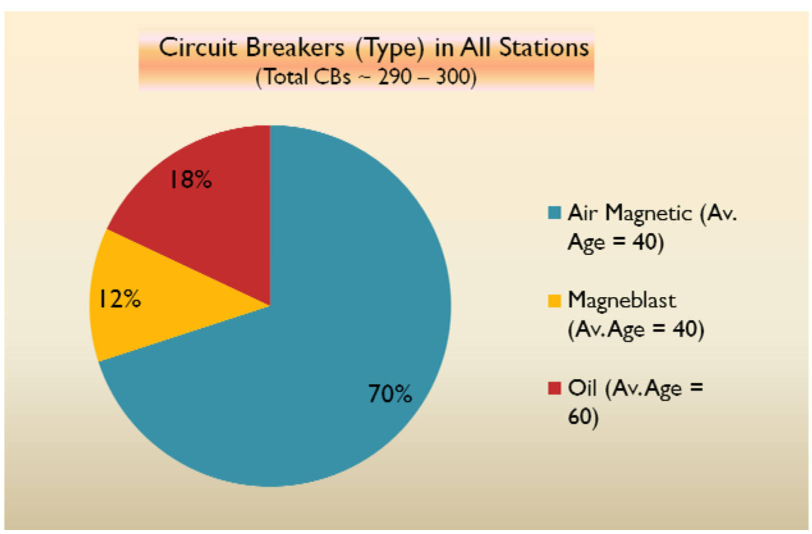
Station Circuit Breakers– Age Groups



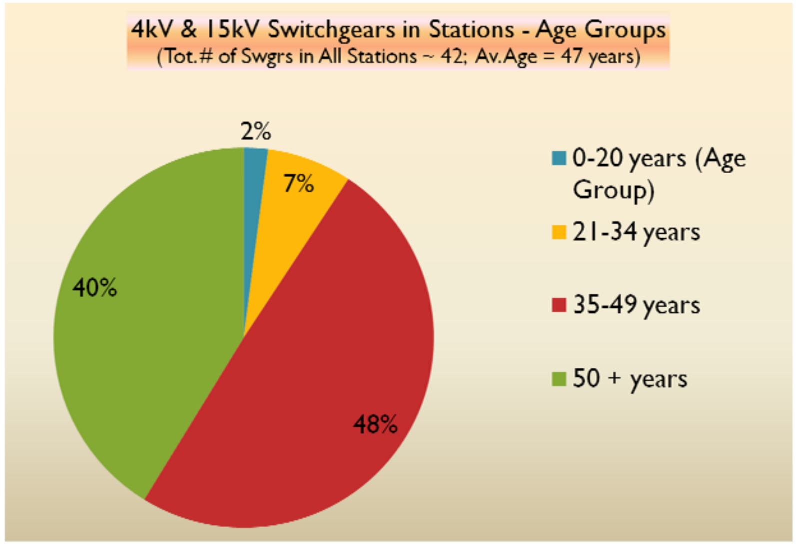
OCBs & ACBs - Built Dates



CB Types in Stations



4kV&15kV Switchgears in Stations - Age



Aging Facilities

- Majority of station buildings & equipment were constructed between 1940's? – 1960's
- Power class & control equipment, i.e. transformers, switching devices & relays etc., are old, obsolete & unreliable
- Frequent breakdowns & maintenance
- Spare parts are not available
- Higher costs to maintain in service

Reasons to Modernize

- Replace old & obsolete equipment
- Improve system Safety & reliability
- Install state of the art equipment that meet current design standards & are more compact
- Increase station power capacity
- Lower maintenance & operating costs

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BOMA-3

Reference:

Summary of Application (Exhibit 1, Tab 2, Schedule 6)

Preamble:

The major drivers of Horizon's Distribution System Plan include the necessary system renewal investments in the distribution system, especially 4/8K asset renewal program, underground renewal programs and buildings renewal programs.

(a) (Exhibit 1, Tab 2, Schedule 6): Please confirm that Horizon uses a Health Index approach developed by Kinetrics to determine when assets should be renewed, through either replacement, refurbishment, more intensive maintenance or otherwise. Please differentiate that approach from an end-of-life approach, based on a design (nameplate) expected asset life. Please discuss.

(b) With respect to the relevance of the Kinetrics ACA Report to the 4kV/8kV /station /renewal program, Horizon states at p4 of the Program Description (Appendix F6 to the DSP) that:

"The updated asset condition information has been used to update the plan, but this new information has just re-enforced the decisions made in previous years, and has had no material impact to the findings and necessity of the overall plan."

(i) Please confirm that, Horizon does not rely on the Kinectrics Report to justify the content of the 4kV/8kV replacement plan. Please discuss fully.

(ii) Please describe in detail the extent to which the 4kV/8kV/station asset renewal investments for 2011-2019 are determined by the Health Index of the relevant assets as determined by Kinectrics. To the extent that under the plan investments are made to replace assets that are not in poor or very poor condition with newer assets. Please discuss and justify. Please provide a quantitative analysis if possible.

(c) Horizon states an unacceptable Health Index distribution occurs when:

(i) at least 20% of the assets within the group have a H1 of either "very poor" or "poor"; or

(ii) the assets within the group, which have a very poor or poor health index, require a significant five-year investment (greater than $5,000,000).

Why does meeting only the second criteria result is an unacceptable HI? Isn't the asset condition the critical factor is, regardless of the likely required investment? Please discuss.

(d) Please provide the comprehensive cost/benefit analysis of the 4kV/8kV replacement program that was done prior to launching the program.

Response:

a) Horizon Utilities confirms that the Health Index approach developed by Kinectrics was a key input mechanism utilized to quantify asset health when evaluating and developing Capital Investment Programs. Horizon Utilities implements proactive System Renewal through the identification, development and implementation of Capital Investment Programs. The results of Kinectrics' ACA were a primary input into the development of Horizon Utilities' Capital Investment Programs with additional inputs coming from system planning and operational performance planning, as described in section 2.1.2 of the DSP included as Appendix 2-4 of Exhibit 2.

The Health Index methodology differs from the end-of-life approach in calculating the renewal investment profiles. For any given asset group, the end-of-life approach identifies zero renewal investment requirements for the assets within the group with a physical age less than the design, or nameplate, expected life. Conversely, a renewal investment requirement is identified for all assets with a physical life greater than the design, or nameplate expected life. The Health Index approach differs in two key areas: i) identification of expected life; and 2) differentiation of effective age from physical age. The Health Index approach acknowledges that although assets within an asset group have an expected life, the actual life of assets within the group varies. As such, failure and survival curves are identified for each asset group demonstrating that some assets will fail prior to their design, or nameplate expected life, while other assets in the group will not fail until their age exceeds their design, or nameplate expected life.

The second differentiator is that effective age can differ from physical age for assets. The Health Index methodology provides the ability to consider the impact of factors other than age (e.g., loading, maintenance and inspection results, operational history) to create an 'effective' age for an asset to use when predicting probability of failure.

b)

i. Horizon Utilities does rely on the Kinectrics' ACA Report. The results form an input into the justification of content of the 4kV and 8kV Renewal Program. Development of the 4kV and 8kV Renewal Program, as fully described in Appendix F of the DSP, included in Exhibit 2, Tab 6, Appendix 2-4, and summarized in part (c) of the response to Interrogatory BOMA-2 involves a multi-step process. This process assesses and ranks the health of: the substation and distribution assets; the feeder dependency; and customer impact for each of the operating areas. The 4kV and 8kV Renewal Program was created prior to Kinectrics' ACA from previous asset management assessments. The results of Kinectrics' ACA report were used to:

- Provide a quantifiable evaluation of the asset condition and as such confirm the poor health of the 4kV and 8kV distribution systems;
- Update substation health scores for substation transformers, switchgear and breakers within the 4kV and 8kV Renewal Program; and
- Aid in identification of investment levels.

Horizon Utilities' statement on page 4 that the Kinectrics' ACA had no material impact to the findings and necessity of the overall plan was referring to the fact the Kinectrics' ACA did not result in any changes to the ranking or prioritization of the operating areas.

ii. The multi-step process through which 4kV/8kV station assets renewal investments are determined is fully described in Appendix F of the DSP included in Exhibit 2, Tab 6, Appendix 2-4, and summarized in part (c) of the response Interrogatory BOMA-2.

Horizon Utilities 4kV and 8kV renewal program involves the renewal of an entire operating area served by multiple substations. Partial renewal of an operating area is not feasible as it reduces the ability to interconnect feeders and create operating contingency and backup within an operating area.

The decision to renew an operating area, which involves the decommissioning of the substations within the area, is based on a composite score which includes the substation and distribution asset health, feeder dependencies within the operating area and customer impacts as a result of service interruptions within the operating area. The age and health of the assets being renewed within an operating area is not homogeneous. Horizon Utilities assesses the existing assets and will reuse existing assets where, in Horizon Utilities' judgement, it can be justified technically. The renewal methodology employed in the 4kV and 8kv Renewal program will result in the renewal of some assets with an acceptable Health Index. However, the operating areas prioritized for conversion contain the oldest distribution infrastructure and as such the proportion of assets not having a 'poor' or 'very poor' Health Index will be very low.

Horizon Utilities has not performed a quantitative analysis on the costs of renewing an entire area versus renewing only the assets with a 'poor' or 'very poor' Health Index distribution. It is not feasible to renew only the assets having a 'poor' or 'very poor' Health Index distribution.

c) Horizon Utilities considers an unacceptable health index occurring from one of two considerations:
    i. at least 20% of the assets within the group have a H1 of either "very poor" or "poor"; or
    ii. the assets within the group, which have a very poor or poor health index, require a significant five-year investment (greater than $5,000,000).

Meeting the criteria identified in (ii) above results in an unacceptable Health Index due to the magnitude of investment required. Horizon Utilities believes that assets forecast to require a capital renewal investment in excess of $5,000,000 in the 2015 to 2019 Test Years form a significant liability and require planning and pacing to manage an investment of this magnitude.

d) When the 4kV and 8kV Renewal Program was launched, a cost/benefit analysis was not completed but the plan was justified from a risk perspective. Please see Horizon Utilities' response to Interrogatory BOMA-2a and 2b for historic details outlining the justification of the plan. In Exhibit 2, Tab 6, Schedule 1, 4kV and 8kV Renewal Program on page 17, Horizon Utilities has quantified the benefit of cost avoidance to substation renewal of $22,500,000 in the 2015-2019 Test Years for a total of $70,000,000 over the remainder of the program. Furthermore in the DSP Exhibit 2, Tab 6, Appendix 2-4, Section 1.1.2 Sources of Cost Savings on the bottom of page 7, Horizon Utilities predicts an annual savings potential on operating and maintenance ("O&M") expenses of up to $30,000 a year per decommissioned substation. Please refer to Horizon Utilities' response to the interrogatory 2-AMPCO 9(a) for further details on the O&M cost avoidance from 4kV and 8kV Renewal. Table 1A in Horizon Utilities' response to Interrogatory 2-Staff-21 illustrates a sample cost comparison for renewal at the higher operating voltage as compared to renewal at the existing voltage which necessitates renewal of a substation.

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BOMA-4

Reference:

DSP Appendix C. KPMG report:

(a) Please provide the terms of reference/retainer letter or equivalent between Horizon and KPMG.

(b) When was KPMG retained to review the Kinetric ACA. When was the final report submitted that "recognized Horizon feedbacks".

(c) Please provide copies of the feedback Horizon provided to KPMG and the additional feedback Horizon supplied on Jan 21, 2014 and Jan 23, 2014 (see page unnumbered, entitled "Version Control" of KPMG Report).

(d) Please explain fully why Horizon hired KPMG to review the Kinetrics study.

(e)

Please confirm that KPMG:

(i) did not do an independent condition analysis of the Horizon assets

(ii) did not create its own Health Index for those assets

(iii) KPMG accepted ACA effective ages, determined by ACA's work

(iv) agreed with Kinetric's choices as to which assets should be "reactively replaced and which assets proactively replaced", and agreed that the distinction was valid

(v) corroborated the Kinetric Flagged-for-Action list by essentially duplicating the calculations by which Kinetrics assembled the list from its effective age of assets analysis

(vi) KPMG concluded that Kinectrics consistently applied its methodology to arrive at effective asset dates, failure/survival curves, and for the production of a Flagged-for-Action list based on asset conditions. If the above an accurate characterization of what KPMG did, to the extent it is not, please explain.

(f) What does Horizon understand an independent assurance review means (p3).

(g) Id, p6: Please provide a copy of the KPMG questionnaire referred to in bullet 3

(h) Please confirm your understanding that under the reactive replacement approach, the assets are replaced as they fail. If that the same as a run-to-failure approach.

(i) Please explain the shift in language from "in theory" to "in practice" in stating the advantages of reactive vs proactive asset replacement differential; "practice" on p9, (last section of second paragraph) vs "theory" in executive summary pl (last sentence in fourth paragraph).

(j) Id, p13:

(i) What is meant by the term "normalized comparison"
(ii) What is meant by the term "look-up methods"

Response:

a) The terms of reference for the work that KPMG carried out on behalf of Horizon Utilities, as provided by KPMG, are shown below:

Background:

Horizon commissioned Kinectrics in 2012 to conduct an asset condition assessment on Horizon's distribution assets with the goal of identifying future investments needed to sustain Horizon's existing asset base. Kinectrics' findings and recommendations have been published in the Horizon Utilities 2013 Asset Condition Assessment report ("the report"). Based on these recommendations, Horizon has prepared a Distribution System Plan ("DSP") that outlines the sustainment capital needed to maintain system performance over the next 20 years. The DSP will be submitted to the Ontario Energy Board ("OEB") in 2014 as part of Horizon's 2015 – 2019 rate application.

To support your rate application, you have asked KPMG, acting as an independent third-party, to complete an independent review of Kinectrics' findings and recommendations and provide a written report. Our role will be to outline certain matters that come to our attention during our work and to offer our comments and recommendations for the Horizon's consideration.

We expect that our procedures will consist solely of inquiry, observation, comparison and analysis of Horizon-provided information. We will rely on the completeness and accuracy of the information provided. Such work does not constitute an audit. Accordingly, we will express no opinion on financial results, internal control or other information.

We acknowledge KPMG's report may be called as evidence during the overall regulatory review process and KPMG may need to participate as an expert witness as prescribed by the OEB's procedural steps and timelines.

Scope of Work

The consultant will be retained as an independent third party to complete the necessary data analysis to ascertain the results contained in the Kinectrics report is reasonable and appropriate. We will review the methodology used to generate the asset health indices, and the resulting "flagged-for-action plans" and the determination of the optimal 20 year investment plan. The following steps will be undertaken in the review process:

- Compare the methodology used by Kinectrics to undertake the probabilistic determination of remaining asset life against current methodologies employed by leading practitioners of asset management and against known published standards
- Based on prioritized asset materiality and asset risks, conduct audits of calculated values: asset health index, effective age, "flagged-for-action plans", and representative investment values for all the asset classes listed in the Kinectrics report
- Conduct a "stage gate review" meeting with key Horizon stakeholders and present the findings of this stage and determine the next appropriate course of action
- Prepare a written report on our observations related to the Kinectrics report

Not In Scope:

- Validation of the raw data quality (accuracy and completeness) used by Kinectrics to generate the results
- Validation of actual asset conditions as expressed in the asset health indices

Intended Outcome:

- We will provide a written opinion of the reasonableness of the results contained in the Horizon Utilities 2013 Asset Condition Assessment report prepared by

Kinectrics. KPMG understands this written opinion may be called as evidence in the overall regulatory review process.

- We will highlight gaps that may be uncovered as a result of the review and that could jeopardize Horizon's DSP used to support the rate application. If applicable, potential mitigating strategies will be identified.
- We will if necessary make ourselves available to participate in the overall regulatory review process as expert witness as prescribed by the OEB's procedural steps and related timelines. We have been made aware of, and agree to accept, the responsibilities that are or may be imposed as set out in Rule 13A of the Ontario Energy Board's Rules of Practice and Procedure. This may include working with Horizon employees and outside legal counsel to:
  - Draft responses to interrogatories, if and when required; and,
  - Participate in technical conference and hearing as an expert witness, if required.

Sample Statement of Findings:

The following statements are potential examples of commentary that would be contained in the KPMG written report to Horizon:

- Based on a review of the methodology used in the Kinectrics report that supports the submission to the regulator, we believe that the approach used to arrive at the presented information is in line with industry practice and generally accepted methodologies. Limited sampling of the inputs to this process illustrated that the hypotheses and data used were adequate given the maturity of the process.
- Based on a review of the methodology used in the Kinectrics report that supports the submission to the regulator, we have found a material weakness in comparison with industry practice. This weakness relates to (e.g. the life expectancy, criticality,) and could lead to an incorrect representation of the (e.g. current state, target state, spend curve). Horizon Utilities has demonstrated awareness of the weakness and has developed a mitigation plan to correct the current results

b) KPMG was initially retained on Nov 20, 2013 as per the engagement letter; with a final report delivered on January 23rd, 2014 as per the Final Report (v1.1).

c) Horizon Utilities has included copies of previous versions of the report and the final report (BOMA-4_Attch_1_v0.9, BOMA-4_Attch_2_v1.0, BOMA-4_Attch_3_v1.1)

d) KPMG was hired to review the Kinectrics' 2013 Asset Condition Assessment ("ACA") in order to:

   a. provide an opinion on Kinectrics' methodology and the resultant findings and recommendations contained in their report;
   b. provide advisory services that consisted of inquiry, observation, analysis and comparison of Horizon-provided information;
   c. provide an independent assessment on the validity and accuracy of methodologies implemented by Kinectrics and confirm the results;
   d. ensure that the ACA represented leading utility practice;
   e. verify the Health Index assessment of Horizon Utilities' assets; and
   f. validate the Flagged-for-Action volumes identified by Kinectrics which provided the basis for the capital investment profile

e)

   i. Horizon Utilities confirms that KPMG did not do an independent condition analysis of Horizon Utilities' assets.
   ii. Horizon Utilities confirms that KPMG did not create its own health index for Horizon Utilities' assets. However, KPMG was able to independently re-create the Health Index determined by Kinectrics based on Kinectrics' methodology.
   iii. KPMG did not accept the ACA effective ages, determined by the ACA work. KPMG recalculated the effective ages of the assets based on Kinectrics' Health Indices. KPMG's results agree with Kinectrics' presented ACA effective ages within a reasonable margin of error.
   iv. KPMG did not provide an opinion as to what asset classes should be reactively replaced versus proactively replaced.

v. Horizon Utilities confirms that KPMG corroborated the Kinectrics' Flagged-for-Action list by independently recreating the calculations performed by Kinectrics. This action confirms that the calculations provided by Kinectrics were reasonable and were based on their published methodology.

vi. Horizon Utilities confirms that KPMG concluded Kinectrics consistently applied its methodology to arrive at effective asset dates, failure/survival curves, and the production of a Flagged-for-Action list based on asset conditions. In addition, KPMG checked for the reasonableness of Kinectrics' recommendations by comparing Kinectrics' Flagged- for-Action results with those derived independently from Typical Useful Life data contained in the Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010). KPMG concluded that the Kinectrics Flagged-for-Action plan is not overstated and is reasonably within the industry accepted asset replacement or refurbishment practices for distribution utilities in Ontario as identified on page 17 of the KPMG Assurance Review.

f) Horizon Utilities understands an independent assurance review to mean:
   a. confirmation that the methodology represents leading utility practice;
   b. confirmation that the execution of the methodology is valid and accurate; and
   c. these confirmations are performed by an unbiased third party not affiliated with Kinectrics or Horizon Utilities.

g) Horizon Utilities has provided a copy of the questionnaire referenced in bullet 3 as BOMA-4-Attch_4_Questionnaire.

h) Horizon Utilities confirms that under the reactive replacement approach, assets are replaced as they fail. The reactive replacement approach is the same as a run-to-failure approach.

i) In the reference from the prefiled evidence for the KPMG Report, the word "theory" was changed to "practice" from v0.9 to v1.0 of the document on page 9 (last section of second paragraph). Regrettably, this outstanding revision was not made in the instance cited in the Executive Summary. This is simply a matter of semantics.

j)
   (i) "Normalized comparison" refers to a method of comparison using a common unit of measure. The common unit of measure chosen to compare the KPMG and

the Kinectrics Flagged-for-Action plans was in Canadian dollars valued as of 2013.

(ii) “Look up methods” refers to the mechanics through which calculations are performed within the software program (Microsoft Excel) to return the probability of asset failure based on asset health and effective age.

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KPMG

cutting through complexity

Horizon Utilities Corporation

Assurance Review of Kinectrics' Asset Condition Assessment Report

Dec 18, 2013

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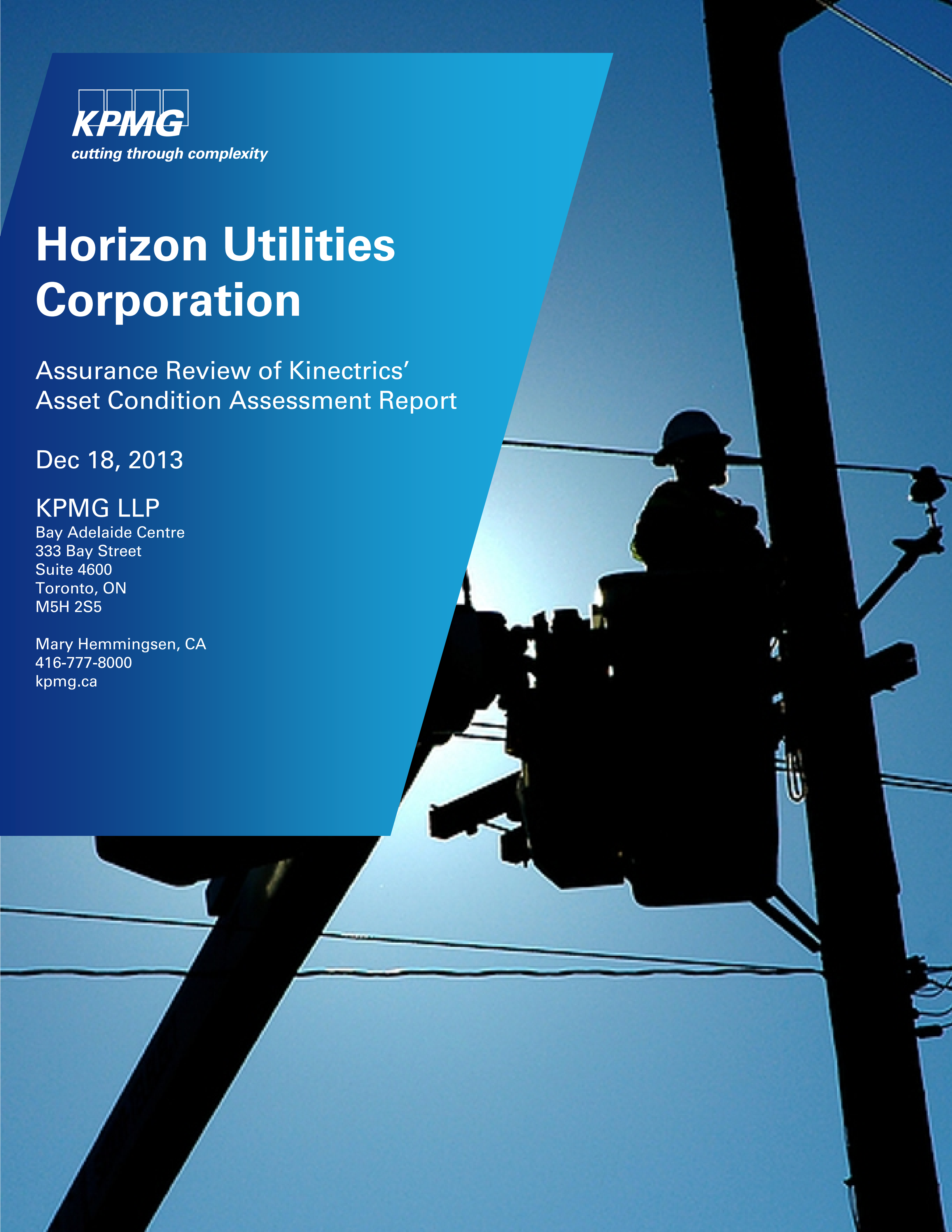


Version Control

Version	Date	By	Description
0.9	Dec 18, 2013	David Cheng	Original Draft for Discussion

Glossary

Chronological Age	age of the asset expressed in years since its installation
Health Index	condition of the asset expressed as a percentage score between 0 and 100% with 100% representing an asset that is in new condition
Proactive Replacement	a strategy that will flag assets for action based on the capability of handling a pre-defined stress level, typically resulting in flagged-for-action prior to the physical end of life.
Reactive Replacement	a strategy that flags assets for action based on the failure rate of the assets
Flagged-for-Action	a state that identifies assets to be considered for replacement or significant refurbishment

Contents

1 Executive Summary

Kinectrics was retained by Horizon between 2012 and 2013 to conduct an assessment on Horizon's distribution assets with the goal of identifying future asset replacement or refurbishment needs in order to sustain the existing assets. Kinectrics findings and recommendations were delivered in their final report dated November 27, 2013 (Kinectrics Inc., 2013).

KPMG was subsequently retained by Horizon as an independent third party to conduct an independent assurance review and provide an opinion on Kinectrics' methodology and the resultant findings and recommendations contained in their report. The procedures employed by KPMG consisted solely of inquiry, observation, analysis and comparison of Horizon-provided information. The findings relied on the completeness and accuracy of the information provided. Such work does not constitute a financial audit. Accordingly, KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG reviewed the methodology published by Kinectrics in their report and compared it with other methodologies used in utilities for predicting probabilistic life expectancy in order to test the validity of the selected methodology used by Kinectrics. The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in other utilities and in actuary science. The inclusion of asset condition in these calculations provides a more sophisticated approach than using just chronological age alone. Kinectrics also employed different predictive models for run-to-failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiated approach is more advanced than what is currently in use at most other utilities and in theory should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

From the described methodology and from the original asset condition data set provided by Horizon to Kinectrics for their assessment, KPMG was successful in recreating independent analytical models to calculate the health indices, effective ages and Flagged-for-Action plans for the 22 distinct classes of assets (see Appendix 3) and compare them with Kinectrics' published results.

The results calculated by Kinectrics and independently calculated by KPMG are within acceptable and reasonable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty years period. The numbers of units identified for replacement or refurbishment by the two respective models differ by less than 0.5% for 19 out of the 22 asset classes and the remaining 3 asset classes differ by no more than 4.5%. Using current standard unit costs provided by Horizon, the cumulative anticipated investment over twenty years is projected to be $693.7M for the Kinectrics model and $694.8M for KPMG's. The projected twenty year difference is an insignificant 0.02% between the two models. Thus, it is KPMG's opinion that Kinectrics has consistently applied their methodology as published in their report using Horizon's asset data. Based on KPMG's assurance review, the resultant Flagged-for-Action plans for the 22 different asset classes have been calculated according to their published methodology.

To test the reasonableness of the effective age calculations, the effective age distribution for each asset class was compared with the chronological age distribution to identify any potential anomalies in applying the asset condition ratings to the asset population. This test demonstrated relative consistency between chronological age and effective age distributions for 21 out of the 22 asset classes. The one exception found was that of the Substation Transformers asset class; its average effective age was found to be significantly below the average chronological age. The result of this age reduction is that this asset class would require less capital sustainment investments going forward than if only the chronological ages were used. Using the effective age distribution, the investment impact would be understated when compared to using the chronological age distribution. This lower level of investment is reflected in the resultant Flagged-for-Action plan for Substation Transformers.

To further test the reasonableness of the Kinectrics results, a comparison of their Flagged-for-Action plan was made against an alternative plan generated from accepted asset life expectancies found in the Asset Depreciation Study for the Ontario Energy Board (OEB) report (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010). Using the published useful life expectancy data for the different asset classes found in the Asset Depreciation Study against the chronological ages of the assets, an alternative twenty year investment plan was created and it was compared to the one created from the Kinectrics report. The twenty year investment plan based on the OEB data projected $706.9M required capital investment versus the $693.7M figure projected from the Kinectrics report. The marginal differences between these two models validated Kinectrics' projections are within accepted industry norms and practices for asset replacements or refurbishments.

In conclusion, it is KPMG's opinion that the approach used to arrive at the presented results in the Kinectrics report is in line with industry practice and generally accepted methodologies. Based on the results found in the independent assurance review, KPMG is of the opinion that the presented methodology has been appropriately and consistently applied using the Horizon supplied asset data in order to derive the final Flagged-for-Action plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been validated to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations.

2 Introduction

Horizon commissioned Kinectrics in 2012 to conduct an asset condition assessment on Horizon's distribution assets with the goal of identifying future investments needed to sustain Horizon's existing asset base. Kinectrics' findings and recommendations have been published in the Horizon Utilities 2013 Asset Condition Assessment report (the "report") (Kinectrics Inc., 2013). Based on these recommendations, Horizon has prepared a Distribution System Plan ("DSP") that outlines the sustainment capital needed to maintain system performance over the next 20 years. The DSP will be submitted to the Ontario Energy Board ("OEB") in 2014 as part of Horizon's 2015 – 2019 rate application.

To support Horizon's rate application, KPMG was retained as an independent third-party, to complete an independent assurance review of the results contained in the Kinectrics report and provide a written opinion on the reasonableness of Kinectrics' findings and recommendations.

The procedures employed consisted solely of inquiry, observation, comparison and analysis of Horizonsupplied information. The findings relied on the completeness and accuracy of the information as provided. Such work does not constitute a financial audit. Accordingly, KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG recognizes this report may be called as evidence during the overall regulatory review process and as such KPMG may be needed to participate as an expert witness as prescribed by the OEB's procedural steps and timelines.

3 Assurance Review Scope

3.1 Scope

As an independent third party, KPMG completed the required data analysis to assess whether the results contained in the Kinectrics report are reasonable and acceptable. KPMG reviewed the methodology and analyses used by Kinectrics to generate the asset health indices, the effective ages and the resulting "Flagged-for-Action" plans for each of the asset classes shown in Table 1 below.

Table 1: Asset Classes in Scope

Asset Class	
Substation Transformers	
Substation Circuit Breakers	
Substation Switchgear	
Pole Mounted Transformers	
Overhead Conductors (in km)	Primary
Overhead Conductors (in km)	Secondary
Overhead Conductors (in km)	Service
Overhead Line Switches	
Wood Poles	
Concrete Poles	
Underground Cables (in km)	Prim. XLPE
Underground Cables (in km)	Prim. PILC
Underground Cables (in km)	Sec. DB
Underground Cables (in km)	Sec. ID
Underground Cables (in km)	Serv. DB
Underground Cables (in km)	Serv. ID
Pad Mounted Transformers	
Pad Mounted Switchgear	
Vault Transformers	
Utility Chambers	
Vaults	
Submersible LBD Switches	

The following inquiry, observation, comparison and analysis were undertaken in the assurance review process:

- Compared the methodology used by Kinectrics to determine the probabilistic remaining asset life expectancy against current methodologies employed by leading practitioners of asset management and against known published standards
- Using the methodology described in the Kinectrics report, created independent calculation engines for health indices, effective age and Flagged-for-Action plans in order to recreate the results contained in the Kinectrics report
- Using standard unit costs provided by Horizon, monetized the respective Flagged-for-Action plans generated by Kinectrics and KPMG in order to test the materiality differences of the two plans
- Compared KPMG calculations against Kinectrics calculations in order to test the validity of the Kinectrics results
- Created an alternative Flagged-for-Action model using the published expected life data contained in the Asset Depreciation Study for the Ontario Energy Board ("OEB") (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010) in order to test the reasonableness of Kinectrics' results with accepted industry standards

3.2 Not In Scope:

The following items were not in scope as part of the review process:

- Validation of the raw data quality (accuracy and completeness) used by Kinectrics to generate the results
- Validation of the selected failure curves used to estimate future asset failures
- Validation of actual asset conditions as expressed in the asset health indices
- Validation of the standard unit costs used in the determination of the Flagged-for-Action investment plans
- Interpretation of the Flagged-for-Action plans to future replacement or refurbishment investments

4 Assurance Review Methodology

The assurance review was conducted using data and information provided by Horizon and publically available information. These included:

- Horizon Utilities 2013 Asset Condition Assessment
- Asset data including asset age, description, and asset condition for each of the asset classes
- Answers to KPMG's questionnaire requesting clarification or additional information
- Asset Depreciation Study for the Ontario Energy Board
- Answers obtained through interviews with Horizon representatives

The approach taken by KPMG to assess the Kinectrics results was to independently recreate the calculations using the data and information presented to KPMG by Horizon and the Kinectrics methodology contained in their report. The intermediate and final outcomes were compared to the published Kinectrics results. The comparisons that were completed included:

- Total population of individual asset classes
- Health indices for each asset class
- Effective ages for each asset class
- Flagged for action profiles for each asset class
- Estimated 20 year monetary capital investment using Horizon supplied standard unit costs

In addition to comparing Kinectrics calculated results with KPMG's results, KPMG also conducted additional tests to confirm the reasonability of Kinectrics' recommendations. The additional tests included:

- Comparison of the calculated effective age distributions against the chronological age distributions for the different asset classes to determine reasonability of the methodology for determining effective age
- Comparison of estimated capital investment required for the Kinectrics' Flagged-for-Action plan and an alternative plan generated from the useful asset life ranges contained in the Depreciation Study for the Ontario Energy Board

5 Assurance Review Results

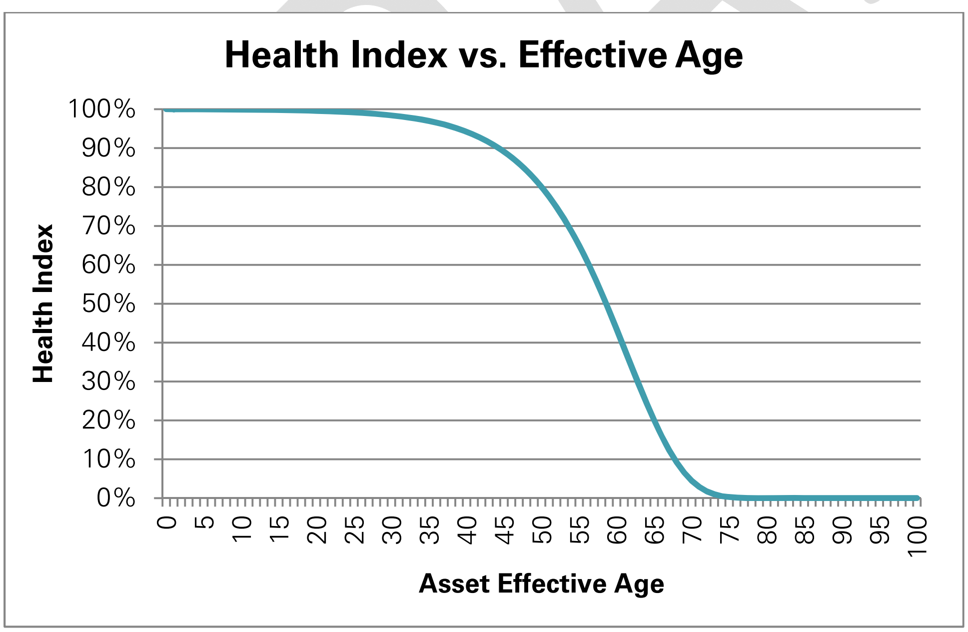
5.1 Kinectrics Methodology

Kinectrics adopted a probabilistic approach to identify expected failures and probable number of units for replacement based on asset condition as represented by the asset health index score. The approach is non-deterministic for reactively replaced assets and deterministic for proactively replaced asset classes. The high-level methodology employed by Kinectrics is shown in Figure 1 below.

Figure 1: Methodology for Determining Flagged-for-Action Plans

The formula used to calculate the health index for each asset class was unique depending on available asset condition data. The health index for each asset was calculated using weighted averages of known asset age and known asset condition parameters and their associated weighting factors. The health index was then used to determine the asset effective age as demonstrated in Figure 2 below using the appropriate survival curve determined jointly by Kinectrics and Horizon for that asset class.

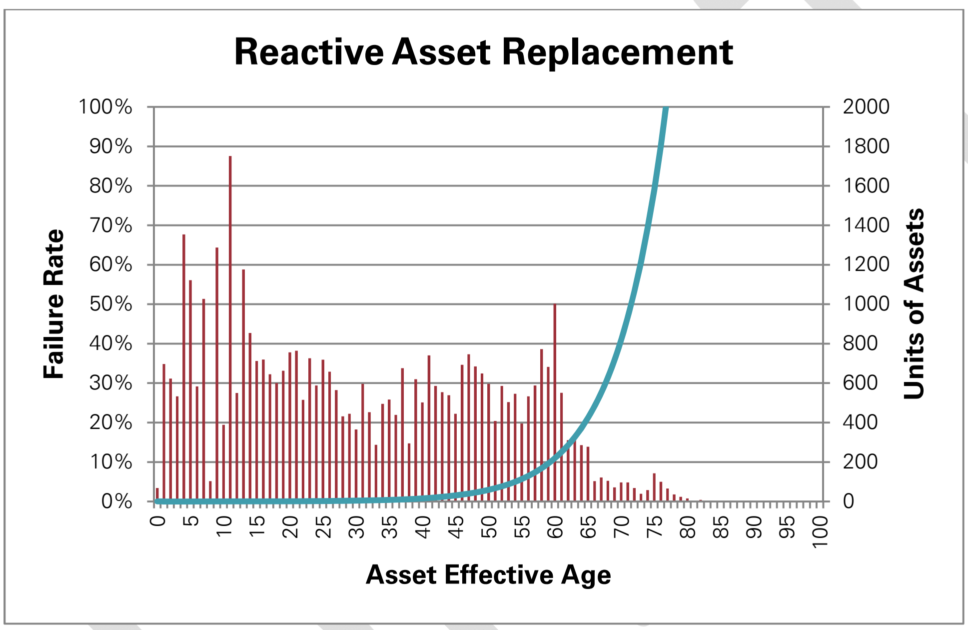
Figure 2: Determining Effective Age from Health Index



This method takes into account known asset condition in order to modify the actual chronological age into an effective age prior to calculating the probability of failure. For example, an asset that is well maintained would have an effective age that is lower than its actual chronological age indicating a lower probability of failure. Conversely, an asset that is overloaded or that is situated in adverse conditions would be de-rated to have a higher effective age as compared to its chronological age leading to a higher probability of failure. This method of predicting asset failure is a more representative method for predicting probability of failure over using only the chronological age.

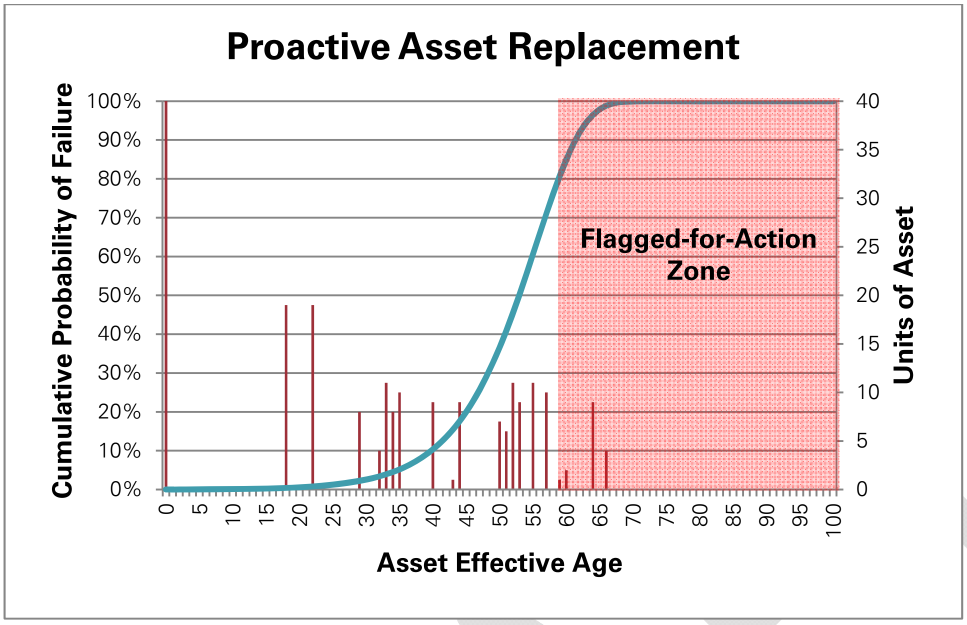
Once the effective age distribution of an asset class is known, it is used to determine probable failure rates. For reactively replaced assets, the effective age distribution is mapped against the assigned failure rate curve for each asset class to determine the quantity of assets projected to fail over the next twenty years (see Figure 3 below).

Figure 3: Flagged for Action Methodology used for Reactively Replaced Assets



For proactively replaced assets, the effective age is mapped against the cumulative probability of failure curve and assets with an effective age that returns a cumulative probability of failure of greater than or equal to 80% are flagged for replacement. Figure 4 represents the methodology used to flag proactively replaced assets.

Figure 4: Flagged for Action Methodology used for Proactively Replaced Assets



The twenty year Flagged-for-Action plan is developed by progressively advancing the effective age of the assets yearly and any assets flagged for replacement are subtracted from the population and replaced with new assets for that year.

The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in actuary science and by other utilities. The inclusion of asset condition in these calculations provides a more sophisticated approach than using just chronological age alone. Kinectrics also employed different predictive models for run to failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiation approach is more advanced than what is currently in use at most other utilities and in theory should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

The assurance review by KPMG of Kinectrics methodologies for calculating Flagged-for-Action plans for both reactively and proactively replaced asset classes confirmed that the respective methodologies were consistently applied across the asset classes. The selected methodology for estimating asset replacement for sustainment purposes is deemed to be reasonable and is an accepted practice within the utilities industry.

5.2 Kinectrics Analytics

The results of the assurance review on the analytics used to determine the Kinectrics results are shown in the following sections.

5.2.1 Asset Populations Comparison

The total population of the individual asset classes were summed and compared to the population cited by Kinectrics in their report. Table 2 summarizes the results of the population comparison.

Table 2: Comparison of Asset Population

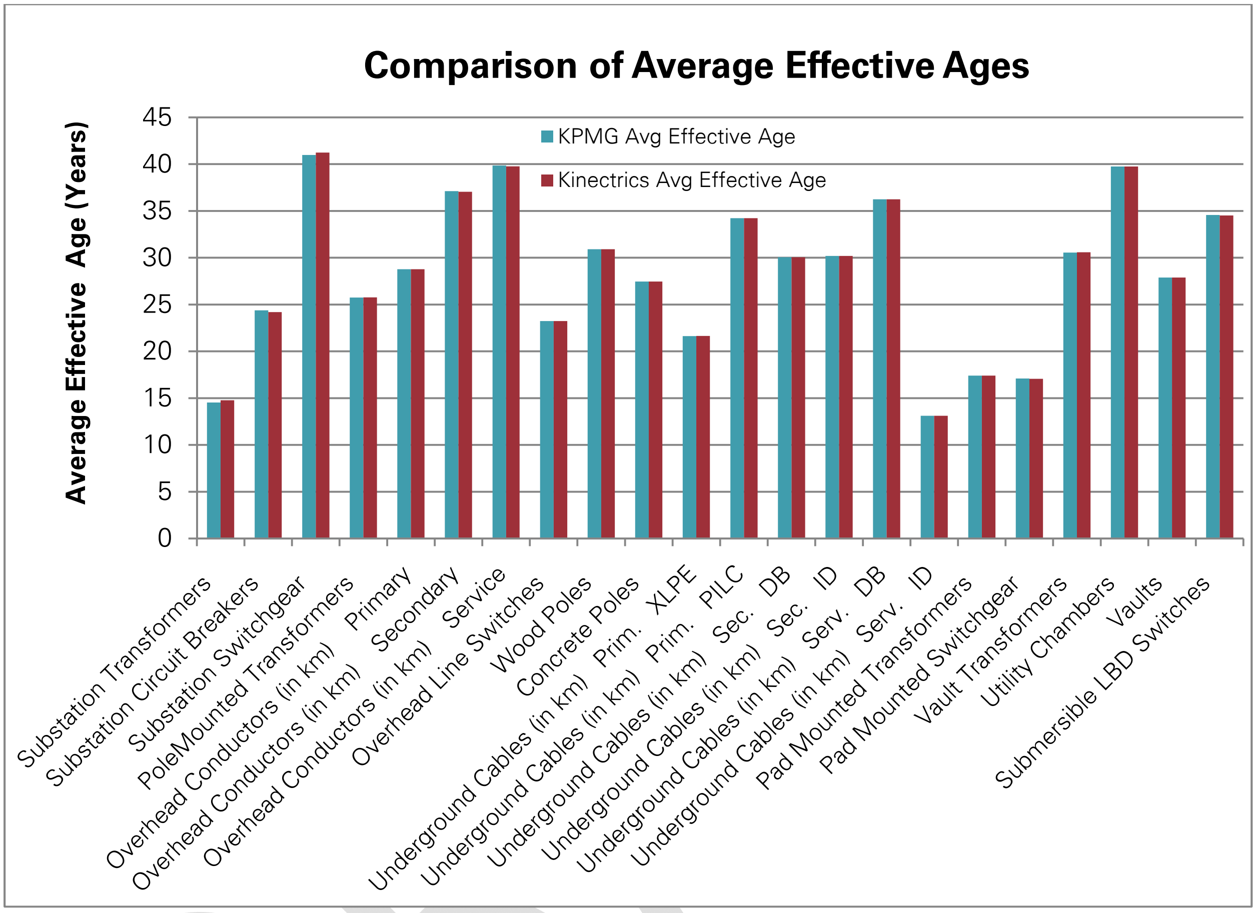
Asset Class		KPMG Total Asset Population	Kinectrics Total Asset Population	Population Difference	Percentage Population Difference
Substation Transformers		70	70	0	0.0%
Substation Circuit Breakers		279	279	0	0.0%
Substation Switchgear		37	37	0	0.0%
Pole Mounted Transformers		12886	12886	0	0.0%
Overhead Conductors (in km)	Primary	3386	3386	0	0.0%
Overhead Conductors (in km)	Secondary	2196	2196	0	0.0%
Overhead Conductors (in km)	Service	1897	1897	0	0.0%
Overhead Line Switches		711	712	-1	-0.1%
Wood Poles		42037	42037	0	0.0%
Concrete Poles		9761	9761	0	0.0%
Underground Cables (in km)	Prim. XLPE	2060	2060	0	0.0%
Underground Cables (in km)	Prim. PILC	1532	1532	0	0.0%
Underground Cables (in km)	Sec. DB	757	757	0	0.0%
Underground Cables (in km)	Sec. ID	533	533	0	0.0%
Underground Cables (in km)	Serv. DB	447	447	0	0.0%
Underground Cables (in km)	Serv. ID	588	588	0	0.0%
Pad Mounted Transformers		5906	5906	0	0.0%
Pad Mounted Switchgear		186	186	0	0.0%
Vault Transformers		4169	4169	0	0.0%
Utility Chambers		2075	2075	0	0.0%
Vaults		3413	3413	0	0.0%
Submersible LBD Switches		117	117	0	0.0%

With but one exception, the asset population in each asset class matches with Kinectrics' published results. The only difference observed is with the Overhead Line Switches where there is 1 unit difference; however the overall impact to the analysis is immaterial. With but this one minor exception, this comparison confirms that the data population is identical to the data population used by Kinectrics in their analysis.

5.2.2 Health Indices and Effective Age Comparisons

Health index calculations were recreated independently by KPMG using Kinectrics' published methodology found in their report (KPMG was not privy to Kinectrics' proprietary calculation models). The calculated health indices were then used to determine the effective ages. When the calculated health indices were compared to Kinectrics results, there were no significant differences identified and the calculated values were then used to determine the effective ages for each asset class. The results of the effective ages are summarized in Figure 5 below.

Figure 5: Comparison of Average Effective Ages

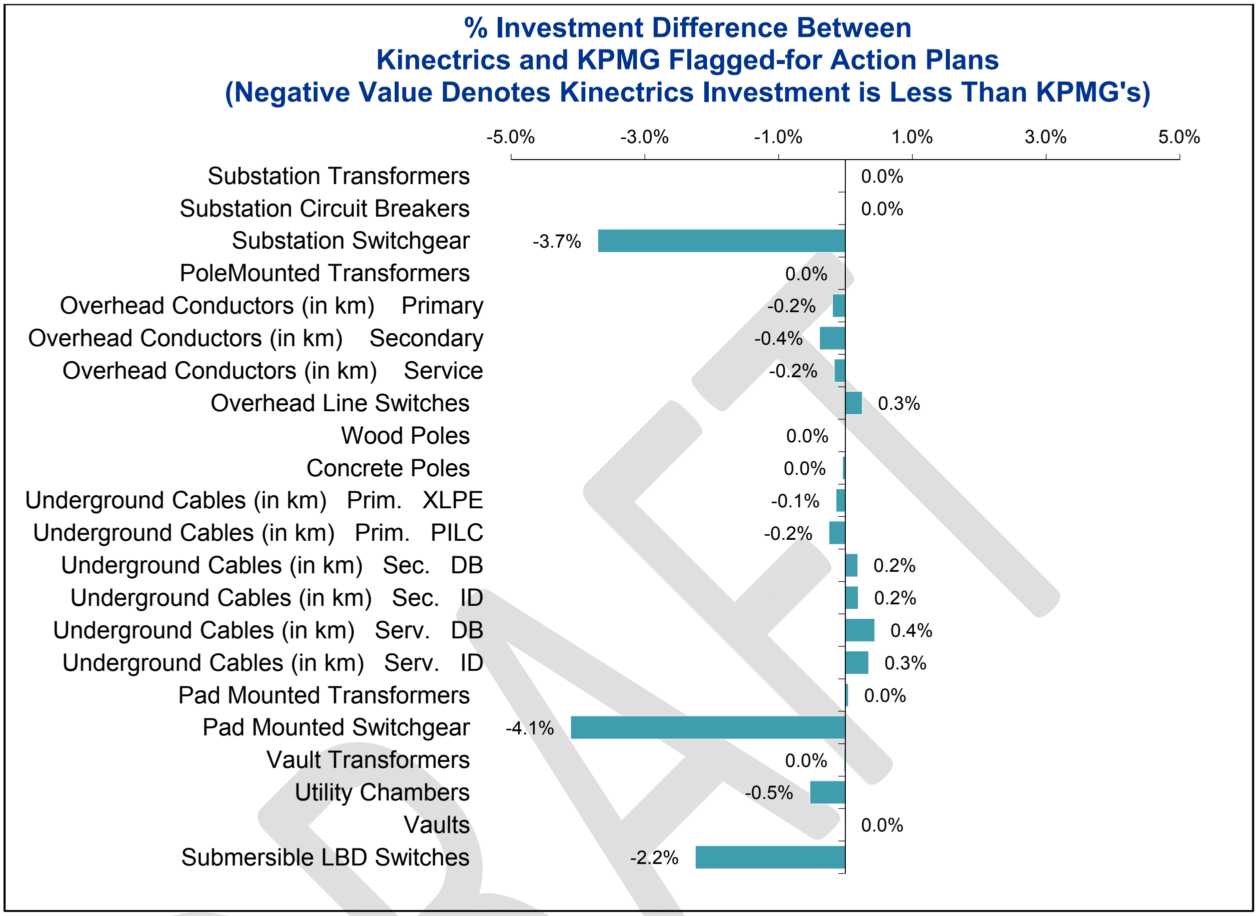


As evidenced by Figure 5 , the average effective age distributions for the different asset classes are virtually identical for both the Kinectrics calculations and KPMG's calculations. Minor differences were observed for the proactively replaced assets (Substation Transformers, Substation Circuit Breakers and Substation Switchgear) but as the subsequent Flagged-for-Action analysis shows, these minor differences did not result in material differences in the Flagged-for-Action plans for these asset classes.

5.2.3 Flagged-for-Action Comparisons

Based on KPMG's calculated effective age distribution for each asset class, the Flagged-for-Action plans for the next twenty years were calculated based on whether the asset was deemed to be proactively replaced or reactively replace. A detailed summary of the units Flagged-for-Action are shown in Appendix 1. The differences in the Flagged-for-Action plans are minor and are deemed to be immaterial. A summary of the percentage differences are shown Figure 6 below.

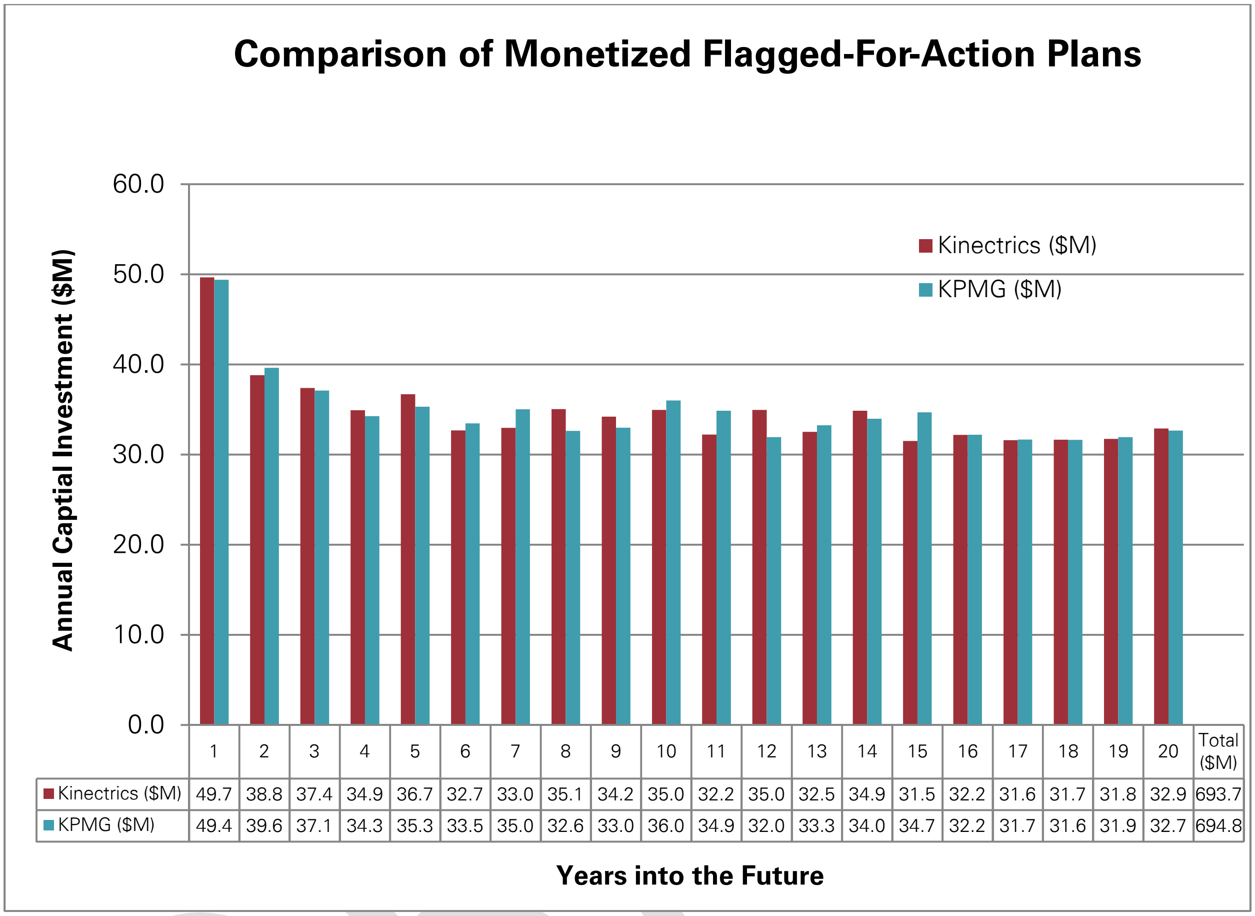
Figure 6: Percentage Difference in Flagged-for-Action Plans between Kinectrics and KPMG



The most significant percentage differences are in the Substation Switchgear, the Pad Mounted Switchgear and the Submersible LBD Switches asset classes. These asset classes have a small number of units in their population (less than 100 in each instance) and any small discrepancies in numeric values result in larger percentage differences when compared to other asset classes. The numerical differences can be found in Appendix 1. The impact of these differences to the Flagged-for-Action plan at the distribution network level over twenty years is immaterial.

Flagged for action unit plans were monetized using standard unit costs in order to effectively allow comparison of the business impact of the identified differences. The standard unit costs used were provided by Horizon for each asset class (see Appendix 3). The resultant estimated investment over twenty years for the respective plans is shown in Figure 7 below.

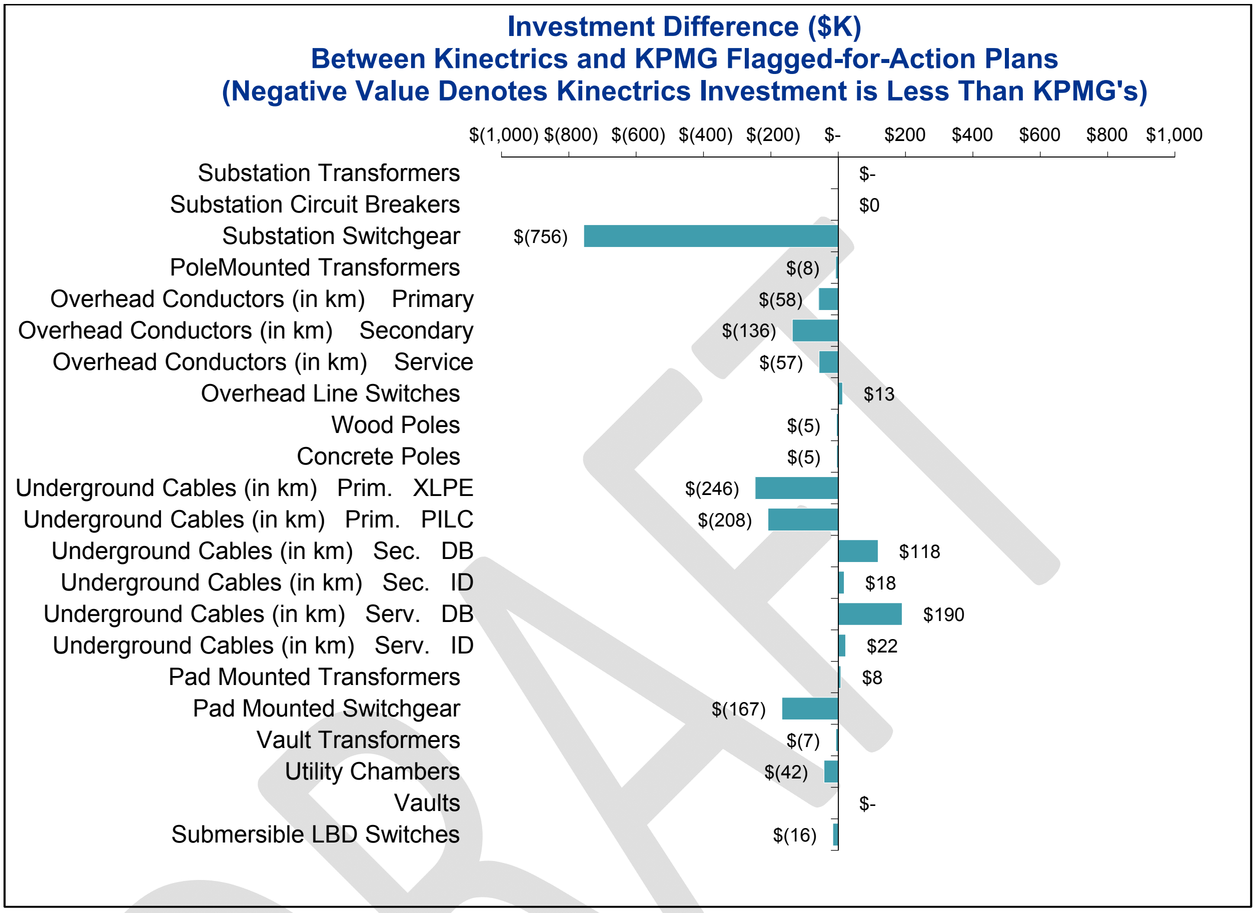
Figure 7: Comparison of Monetized Flagged-for-Action Plans



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
KPMG ($M)	49.4	39.6	37.1	34.3	35.3	33.5	35.0	32.6	33.0	36.0	34.9	32.0	33.3	34.0	34.7	32.2	31.7	31.6	31.9	32.7	694.8

This monetized plan is meant to serve as a normalized comparison in dollar terms between the two respective Flagged-for-Action plans and it is not meant to be used as the definitive guide for Horizon's future capital investments. The two plans returned very similar total investment values over the twenty year span supporting the reasonableness of the calculations presented in the Kinectrics report. The total investment differs by only $1.1 million over twenty years or 0.02% for the period. The estimated monetary differences for each asset class are summarized in Figure 8 below.

Figure 8: Comparison of Estimated Value of Flagged-for-Action Plans between Kinectrics and KPMG



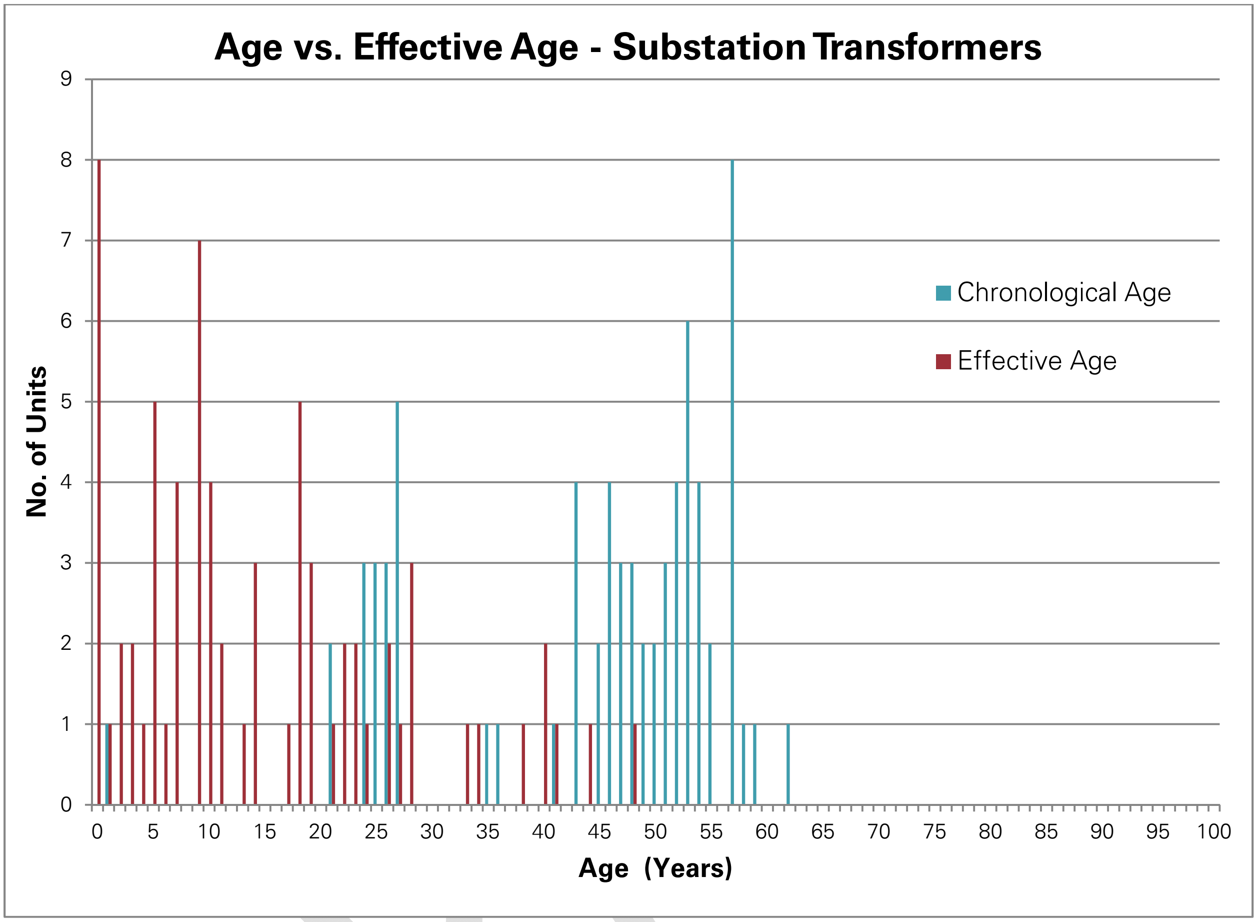
The results of the analysis show that Kinectrics' resulting end calculations can be replicated independently within a very small margin of error. It is KPMG's opinion that Kinectrics has accurately applied their published methodology and formulas contained in their report against the Horizon supplied asset data set.

5.3 Tests for Reasonableness

5.3.1 Comparison of Effective Age against Chronological Age

In order to test whether the health indices and the associated effective ages were reasonable, the calculated effective age was compared to the chronological age in terms of age distribution and overall average age for each of the asset classes. The age distribution comparison test was meant to reveal whether the incorporation of the asset condition parameters played a major role in altering the chronological age in a material way. Figure 9 below is an example of the comparison conducted for each asset class.

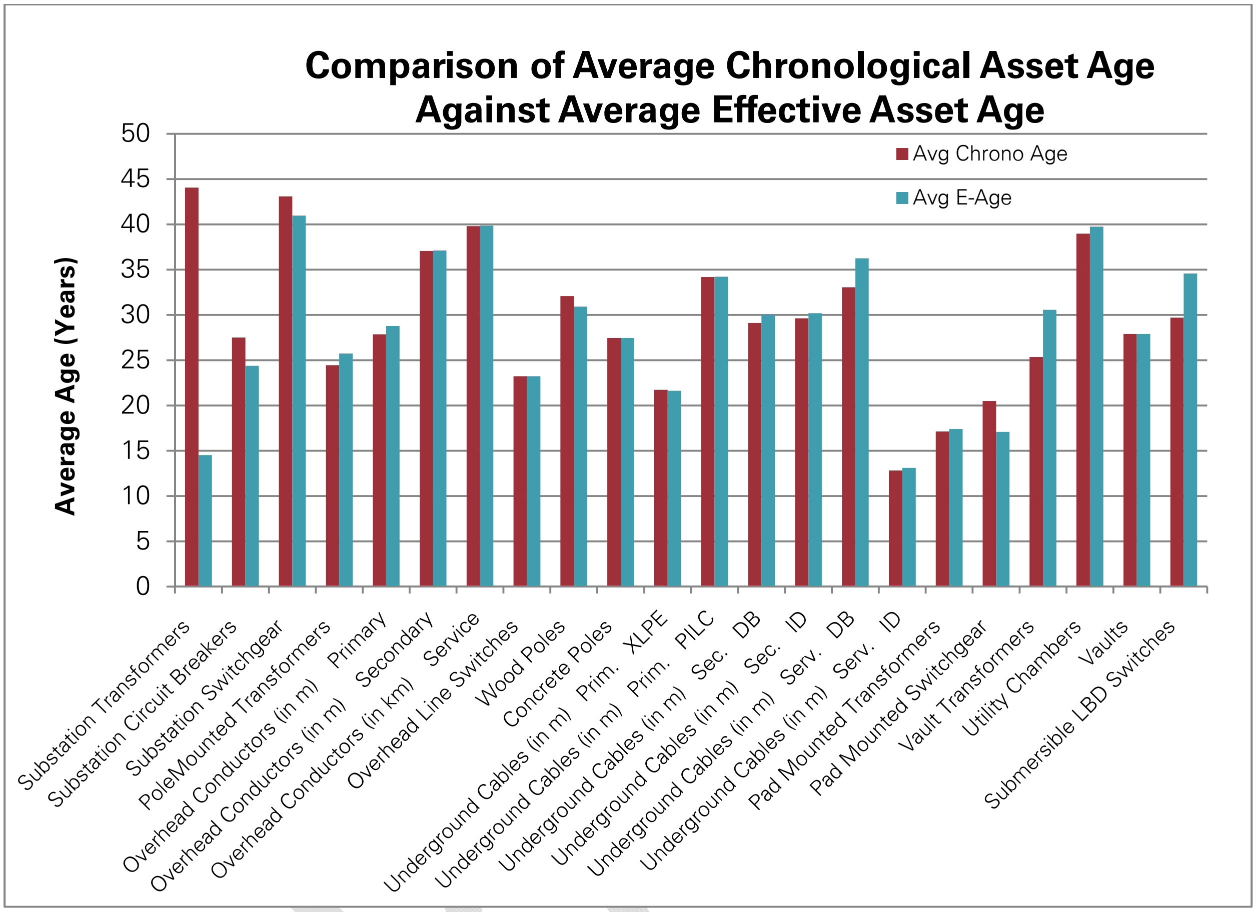
Figure 9: Example of Chronological Age versus Effective Age Comparison



The conversion of chronological age to effective age as a result of having asset condition parameters applied did shift the age distribution significantly for some asset classes. The differences between the average effective ages and the average chronological ages can be seen in Figure 10 below. The most significant shift is in the Substation Transformer asset class as the average effective age is significantly below the average chronological age. This phenomenon as explained by Horizon representatives is the result of having significant maintenance and testing programs in place for this relatively old asset class to ensure their performance and reliability as these assets are key core components of the distribution system.

This test revealed that the use of effective ages to calculate the Flagged-for-Action plans would generate different end results than plans generated from chronological ages. However, the Flagged-for-Action differences in all the asset classes with the exception of the Substation Transformers would be reasonably close between the two different age profiles. For the Substation Transformers, the Flagged-for-Action plan using the assets' effective ages would significantly understate the number of units to be Flagged-for-Action when compared with a plan generated by the use of chronological age alone. Using effective ages to determine the Flagged-for-Action plan was deemed to be more reflective of actual asset conditions than using just chronological age alone.

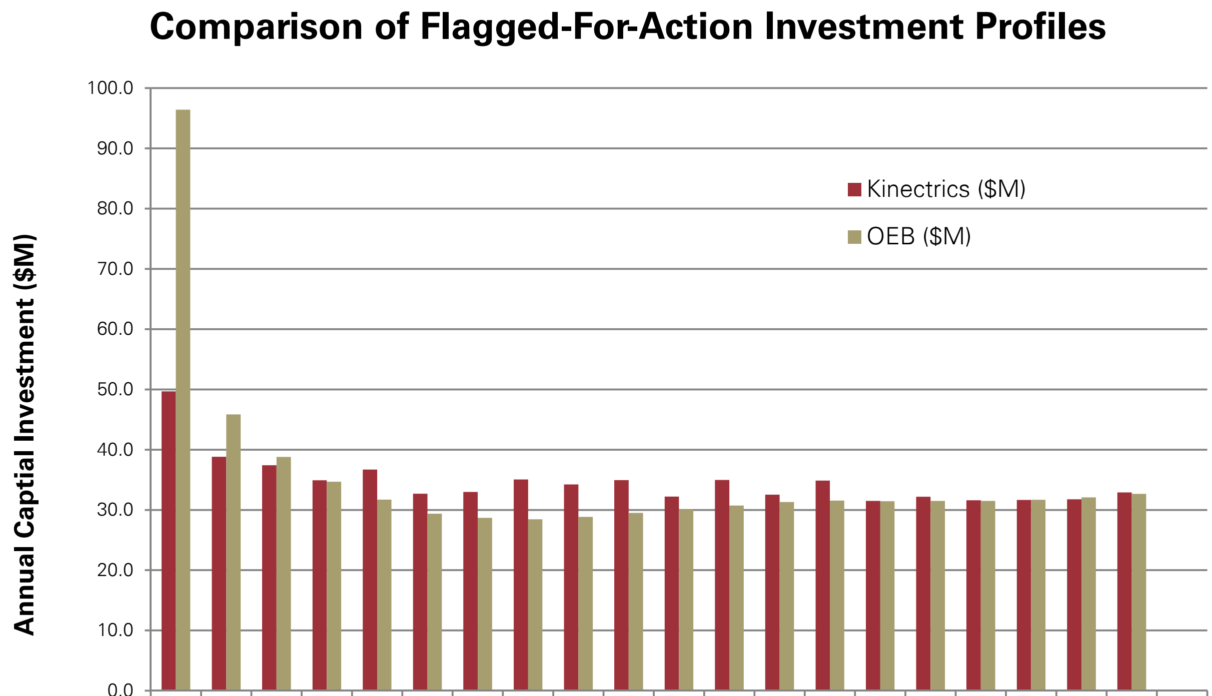
Figure 10: Comparison of Average Effective Ages against Average Chronological Ages



5.3.2 Comparison of Kinectrics' Flagged-for-Action Plan against Accepted Asset Life Standards

The final test to determine reasonability of the Kinectrics Flagged-for-Action plan was to compare the total plan against published and accepted industry standards for asset life expectancies. The standard life expectancies chosen for comparison were those published in the Asset Depreciation Study for the Ontario Energy Board (see Appendix 2). The published Typical Useful Life (TUL) and the Maximum Useful Life (MUL) were used to estimate the failure curve (f_t) and the cumulative probability of failure (P_f) for use in projecting asset replacements. Based on interpretation of the OEB report, the TUL was assigned 20% P_f, and the MUL was assigned 85% P_f. Failure curves were subsequently developed using the published TUL and MUL figures; the only exception was for the Submersible LBD Switches for which figures were not available in the OEB report. For this asset class, the UG Vault switch values for TUL and MUL were used as a proxy. Flagged for action plans for each asset class were then calculated using the chronological age as the OEB useful lives data was developed for use with chronological asset age. The comparison of the normalized monetary results for the two different Flagged-for-Action plans is shown in Figure 11 below.

Figure 11: Comparison of Kinectrics Flagged-for-Action Plan versus Plan Generated from OEB Data



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
OEB ($M)	96.4	45.9	38.8	34.7	31.7	29.4	28.7	28.4	28.9	29.5	30.1	30.7	31.3	31.6	31.4	31.5	31.5	31.7	32.1	32.7	706.9

Years into the Future

The total estimated investment for the two different plans over twenty years is within 2% of each other. The results calculated from the OEB life expectancies are heavily front-end loaded suggesting that model assesses Horizon's asset base as being closer to end of life than Kinectrics effective age model. This test result suggests that the Kinectrics Flagged-for-Action plan is reasonably within accepted practices for distribution utilities in Ontario.

6 Conclusions

Based on an independent assurance review of the methodology and analytics used in the Kinectrics report, it is KPMG's opinion that the approach used to arrive at the presented results is in line with industry practice and generally accepted methodologies. KPMG is of the opinion that the presented methodology has been appropriately and consistently applied against the Horizon supplied asset data in order to derive the final Flagged-for-Action plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been independently validated by KPMG to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations.

Appendix 1 Comparison of Twenty Year Flagged-for-Action Plans

Assets Class	Source	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total
Substation Transformers	Kinectrics	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	2	5
Substation Transformers	KPMG	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	1	2	5
Substation Circuit Breakers	Kinectrics	16	0	10	0	11	0	9	0	17	0	7	0	0	0	0	9	1	0	0	9	89
Substation Circuit Breakers	KPMG	16	0	10	0	11	0	9	11	6	7	0	0	0	0	0	9	1	0	0	9	89
Substation Switchgear	Kinectrics	1	0	1	1	4	0	0	4	2	4	0	4	1	4	0	0	0	0	0	0	26
Substation Switchgear	KPMG	0	1	1	0	2	1	3	0	1	5	4	0	2	3	4	0	0	0	0	0	27
PoleMounted Transformers	Kinectrics	593	277	232	218	215	217	220	223	226	228	229	229	230	230	231	234	238	244	252	262	5028
PoleMounted Transformers	KPMG	594	277	232	218	215	217	220	223	226	228	229	229	230	230	232	234	238	244	252	262	5029
Overhead Conductors (in km) Primary	Kinectrics	53	45	40	37	34	32	31	30	29	30	30	31	32	32	32	33	33	33	33	34	684
Overhead Conductors (in km) Primary	KPMG	53	46	41	37	34	32	31	30	29	30	30	31	32	32	33	33	33	33	33	34	685
Overhead Conductors (in km) Secondary	Kinectrics	86	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	843
Overhead Conductors (in km) Secondary	KPMG	87	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	846
Overhead Conductors (in km) Service	Kinectrics	97	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	32	30	28	27	809
Overhead Conductors (in km) Service	KPMG	99	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	31	30	28	27	810
Overhead Line Switches	Kinectrics	31	26	23	22	20	20	19	18	19	18	18	18	17	17	17	17	16	17	17	17	387
Overhead Line Switches	KPMG	31	26	23	22	21	20	19	19	18	18	18	17	17	17	17	17	17	17	17	17	386
Wood Poles	Kinectrics	1509	1103	1011	967	935	905	876	845	814	782	752	724	699	678	662	648	637	627	619	611	16404
Wood Poles	KPMG	1509	1103	1011	968	935	906	876	845	814	782	752	724	699	678	661	648	637	627	619	611	16405
Concrete Poles	Kinectrics	97	98	100	101	103	104	105	107	108	109	110	111	112	114	115	118	119	121	123	126	2201
Concrete Poles	KPMG	97	98	100	101	103	104	105	106	108	109	110	111	112	114	116	117	119	121	124	126	2202
Underground Cables (in km) Prim. XLPE	Kinectrics	126	103	96	91	88	85	83	80	78	76	74	72	71	70	69	68	67	66	66	66	1595
Underground Cables (in km) Prim. XLPE	KPMG	127	103	95	91	88	85	83	80	78	76	74	73	71	70	69	68	67	67	66	66	1597
Underground Cables (in km) Prim. PILC	Kinectrics	11	11	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	339
Underground Cables (in km) Prim. PILC	KPMG	12	12	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	340
Underground Cables (in km) Sec. DB	Kinectrics	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	519
Underground Cables (in km) Sec. DB	KPMG	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	518
Underground Cables (in km) Sec. ID	Kinectrics	21	21	21	20	20	19	19	19	18	18	18	18	17	17	17	17	17	16	16	16	365
Underground Cables (in km) Sec. ID	KPMG	21	21	20	20	20	19	19	19	18	18	18	18	17	17	17	17	16	16	16	16	364
Underground Cables (in km) Serv. DB	Kinectrics	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	352
Underground Cables (in km) Serv. DB	KPMG	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	350
Underground Cables (in km) Serv. ID	Kinectrics	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15	257
Underground Cables (in km) Serv. ID	KPMG	10	11	11	11	11	12	12	12	12	13	13	13	13	14	14	14	14	15	15	15	256
Pad Mounted Transformers	Kinectrics	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Transformers	KPMG	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Switchgear	Kinectrics	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	70
Pad Mounted Switchgear	KPMG	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	73
Vault Transformers	Kinectrics	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	162	156	150	144	139	4250
Vault Transformers	KPMG	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	163	156	150	144	139	4251
Utility Chambers	Kinectrics	12	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	23	24	25	26	373
Utility Chambers	KPMG	13	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	24	24	25	26	375
Vaults	Kinectrics	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Vaults	KPMG	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Submersible LBD Switches	Kinectrics	14	8	7	6	5	5	5	4	4	4	3	3	3	3	2	2	2	2	2	3	87
Submersible LBD Switches	KPMG	14	8	7	6	5	5	5	4	4	4	4	3	3	3	3	3	2	2	2	2	89

Appendix 2 Summary of OEB's Asset Useful Lives

F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS Category | Component | Type			USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
			Battery bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
	18	Station Switch			30	50	60	M	L	M	M	M	L

* OH = Overhead Lines System TS & MS = Transformer and Municipal Stations

** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS Category | Component | Type		USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
TS & MS	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
TS & MS	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
TS & MS	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
TS & MS	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
UG	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
UG	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
UG	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
UG	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
UG	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
UG	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
UG	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
UG	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
UG	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
UG	33	Network Transformers	Protector	20	35	40						
UG	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
UG	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
UG	36	UG Foundations		35	55	70	M	NI	M	L	L	M
UG	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
UG	37	UG Vaults	Roof	20	30	45						
UG	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
UG	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
UG	40	Ducts		30	50	85	H	NI	M	NI	NI	L
UG	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
UG	42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H

* TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

Appendix 3 Standard Unit Costs Provided by Horizon Utilities

Assets Class		Average Unit Cost ($K)
Substation Transformers		$ 150.0
Substation Circuit Breakers		$ 45.7
Substation Switchgear		$ 755.6
Pole Mounted Transformers		$ 7.7
Overhead Conductors (in km)	Primary	$ 43.3
Overhead Conductors (in km)	Secondary	$ 41.4
Overhead Conductors (in km)	Service	$ 41.5
Overhead Line Switches		$ 13.7
Wood Poles		$ 4.4
Concrete Poles		$ 5.0
Underground Cables (in km)	Prim. XLPE	$ 108.4
Underground Cables (in km)	Prim. PILC	$ 247.5
Underground Cables (in km)	Sec DB	$ 125.0
Underground Cables (in km)	Sec ID	$ 25.2
Underground Cables (in km)	Serv. DB	$ 124.4
Underground Cables (in km)	Serv. ID	$ 24.9
Pad Mounted Transformers		$ 16.7
Pad Mounted Switchgear		$ 55.7
Vault Transformers		$ 6.8
Utility Chambers		$ 21.0
Vaults		$ 7.4
Submersible LBD Switches		$ 8.1

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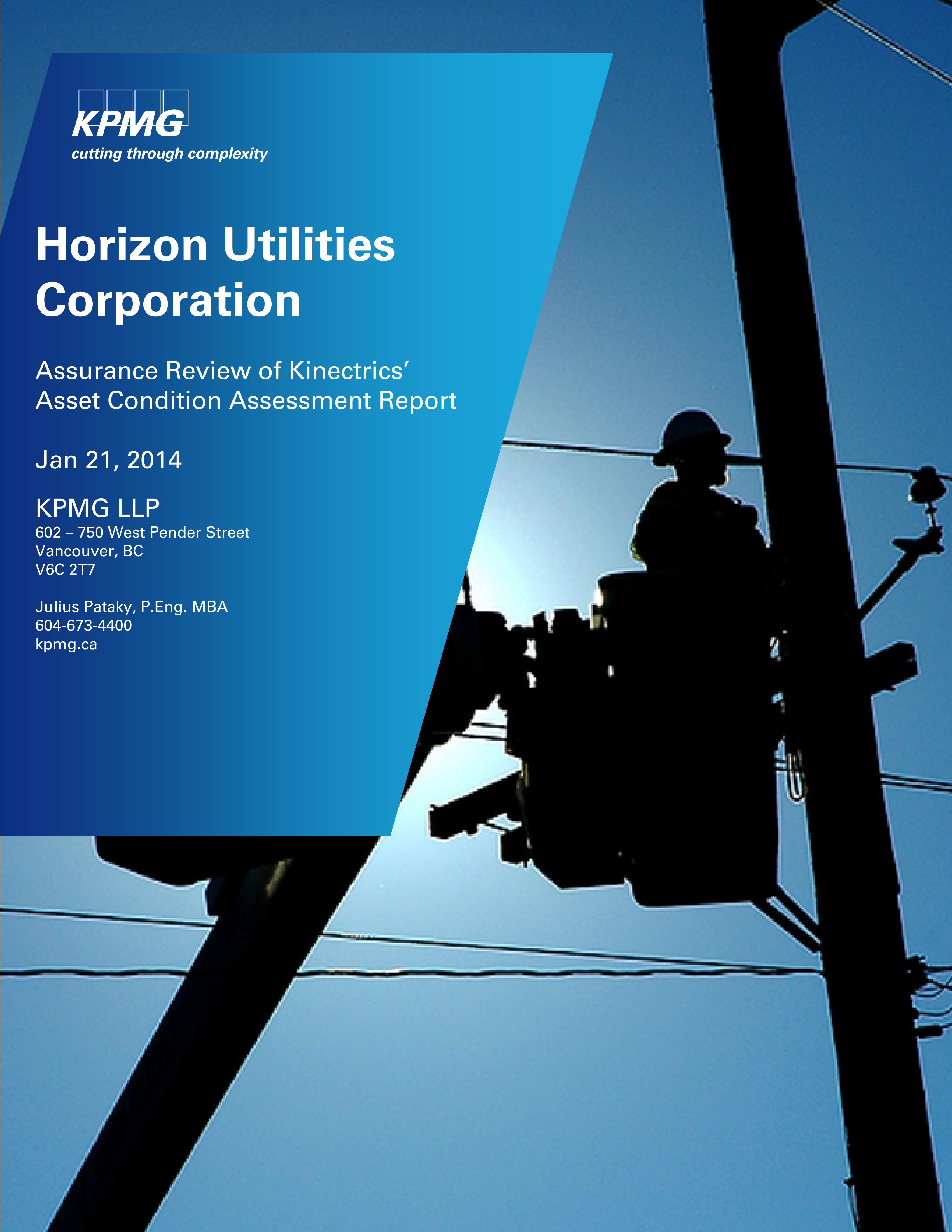

cutting through complexity

Horizon Utilities Corporation

Assurance Review of Kinectrics' Asset Condition Assessment Report

Jan 21, 2014

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Version Control

Version	Date	By	Description
0.9	Dec 18, 2013	David Cheng	Original Draft for Discussion
1.0	Jan 21, 2014	David Cheng	Incorporated Horizon Feedback

Glossary

Chronological Age	age of the asset expressed in years since its installation
Health Index	condition of the asset expressed as a percentage score between 0 and 100% with 100% representing an asset that is in new condition
Proactive Replacement	a strategy that will flag assets for action based on the capability of handling a pre-defined stress level, typically resulting in Flagged-for-Action prior to the physical end of life.
Reactive Replacement	a strategy that flags assets for action based on the failure rate of the assets
Flagged-for-Action	a state that identifies assets to be considered for replacement or significant refurbishment

Contents

1 Executive Summary

Based on an independent assurance review of the methodology and analytics used in the Kinectrics Inc. ("Kinectrics") report titled "Horizon Utilities 2013 Asset Condition Assessment" (Kinectrics Inc., 2013), it is KPMG's opinion that the approach used to arrive at the presented results is in line with industry practice and generally accepted methodologies. KPMG is of the opinion that the presented methodology has been appropriately and consistently applied against the Horizon Utilities Corporation ("Horizon") supplied asset data in order to derive the final Flagged-for-Action (assets flagged for replacement or refurbishment) plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been independently validated by KPMG to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations.

Kinectrics was retained by Horizon between 2012 and 2013 to conduct an assessment on Horizon's distribution assets with the goal of identifying future asset replacement or refurbishment needs in order to sustain the existing assets. Kinectrics findings and recommendations were delivered in their final report dated November 27, 2013 (Kinectrics Inc., 2013).

KPMG was subsequently retained by Horizon as a third party to conduct an independent assurance review and provide an opinion on Kinectrics' methodology and the resultant findings and recommendations contained in their report. KPMG provided advisory services that consisted of inquiry, observation, analysis and comparison of Horizon-provided information. The findings relied on the completeness and accuracy of the information provided. KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG reviewed the methodology published by Kinectrics in their report and compared it with other methodologies used in utilities for predicting probabilistic life expectancy of assets in order to test the validity of the selected methodology used by Kinectrics. The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in other utilities and in actuary science. The inclusion of asset condition in these calculations provides a more sophisticated approach than that of using chronological age alone. Kinectrics also employed different predictive models for run-to-failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiated approach is more advanced than that which is currently in use at most other utilities and in theory should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

From the described methodology and from the original asset condition data set provided by Horizon to Kinectrics for their assessment, KPMG was successful in recreating independent analytical models to calculate the health indices, effective ages and Flagged-for-Action plans for the 22 distinct classes of assets (see Appendix 1) and comparing them with Kinectrics' published results.

The results calculated by Kinectrics and independently calculated by KPMG are within an acceptable and reasonable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. The numbers of units identified for replacement or refurbishment by the two respective models differ by less than 0.5% for 19 out of the 22 asset classes and the remaining 3 asset classes differ by no more than 4.5%. Using current standard unit costs provided by Horizon, the cumulative anticipated investment over twenty years is projected to be $693.7M for the Kinectrics model and $694.8M for that of KPMG. The projected twenty year difference is 0.02%; this difference is insignificant between the two models. Thus, it is KPMG's opinion that Kinectrics has consistently applied their methodology as published in their report using Horizon's asset data.

To test the reasonableness of the effective age calculations, the effective age distribution for each asset class was compared with the chronological age distribution to identify any potential anomalies in applying the asset condition ratings to the asset population. This test demonstrated relative consistency between chronological age and effective age distributions for 21 out of the 22 asset classes. The Substation Transformers asset class was the only exception found; its average effective age was found to be significantly below the average chronological age. The result of this age reduction is that this asset class would require less capital sustainment investments going forward than if the chronological age was the only criterion used. Using the effective age distribution, the investment impact would be understated when compared to using the chronological age distribution. This lower level of investment is reflected in the resultant Flagged-for-Action plan for Substation Transformers.

To further test the reasonableness of the Kinectrics results, a comparison of their Flagged-for-Action plan was made against an alternative plan generated from accepted asset life expectancies found in the Asset Depreciation Study for the Ontario Energy Board (OEB) report (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010). Using the published useful life expectancy data for the different asset classes found in the Asset Depreciation Study against the chronological ages of the assets, an alternative twenty year investment plan was created by KPMG. This alternative OEB-based investment plan was compared to the one created by Kinectrics. The twenty year investment plan based on the OEB data projected $706.9M required capital investment versus the $693.7M figure projected by Kinectrics. The marginal differences between these two models validated that Kinectrics' projections are within accepted industry norms and practices for asset replacements or refurbishments.

In conclusion, it is KPMG's opinion that the approach and the calculations used to arrive at the presented results in the Kinectrics report is in line with industry practice and generally accepted methodologies.

2 Introduction

In 2012, Horizon commissioned Kinectrics to conduct an asset condition assessment on Horizon's distribution assets with the goal of identifying future investments needed to sustain Horizon's existing asset base. Kinectrics' findings and recommendations have been published in the Horizon Utilities 2013 Asset Condition Assessment report (the "report") (Kinectrics Inc., 2013). Based on these recommendations, Horizon has prepared a Distribution System Plan ("DSP") that outlines the sustainment capital needed to maintain system performance over the next 20 years. The DSP will be submitted to the Ontario Energy Board ("OEB") in 2014 as part of Horizon's 2015 – 2019 rate application.

To support Horizon's rate application, KPMG was retained as an independent third-party, to complete an independent assurance review of the results contained in the Kinectrics report and provide a written opinion on the reasonableness of Kinectrics' findings and recommendations.

The procedures employed consisted solely of inquiry, observation, comparison and analysis of Horizon supplied information. The findings relied on the completeness and accuracy of the information as provided. KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG recognizes this report may be called as evidence during the overall regulatory review process and as such KPMG may be needed to participate as an expert witness as prescribed by the OEB's procedural steps and timelines.

3 Assurance Review Scope

3.1 Scope

As an independent third party, KPMG completed the required data analysis to assess whether the results contained in the Kinectrics report are reasonable and acceptable. KPMG reviewed the methodology and analyses used by Kinectrics to generate the asset health indices, the effective ages and the resulting "Flagged-for-Action" plans for each of the asset classes shown in Table 1 below.

Table 1: Asset Classes in Scope

Asset Class	
Substation Transformers	
Substation Circuit Breakers	
Substation Switchgear	
Pole Mounted Transformers	
Overhead Conductors (in km)	Primary
Overhead Conductors (in km)	Secondary
Overhead Conductors (in km)	Service
Overhead Line Switches	
Wood Poles	
Concrete Poles	
Underground Cables (in km)	Prim. XLPE
Underground Cables (in km)	Prim. PILC
Underground Cables (in km)	Sec. DB
Underground Cables (in km)	Sec. ID
Underground Cables (in km)	Serv. DB
Underground Cables (in km)	Serv. ID
Pad Mounted Transformers	
Pad Mounted Switchgear	
Vault Transformers	
Utility Chambers	
Vaults	
Submersible LBD Switches	

The following inquiry, observation, comparison and analysis were undertaken in the assurance review process:

- Compared the methodology used by Kinectrics to determine the probabilistic remaining asset life expectancy against current methodologies employed by leading practitioners of asset management and against known published standards
- Using the methodology described in the Kinectrics report, created independent calculation engines for health indices, effective age and Flagged-for-Action plans in order to recreate the results contained in the Kinectrics report
- Using standard unit costs provided by Horizon, monetized the respective Flagged-for-Action plans generated by Kinectrics and KPMG in order to test the materiality differences of the two plans
- Compared KPMG calculations against Kinectrics calculations in order to test the validity of the Kinectrics results
- Created an alternative Flagged-for-Action model using the published expected life data contained in the Asset Depreciation Study for the Ontario Energy Board ("OEB") (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010) in order to test the reasonableness of Kinectrics' results with accepted industry standards

3.2 Not In Scope:

The following items were not in scope as part of the review process:

- Validation of the raw data quality (accuracy and completeness) used by Kinectrics to generate the results
- Validation of the selected failure curves used to estimate future asset failures
- Validation of actual asset conditions as expressed in the asset health indices
- Validation of the standard unit costs used in the determination of the Flagged-for-Action investment plans
- Interpretation of the Flagged-for-Action plans to future replacement or refurbishment investments

4 Assurance Review Methodology

The assurance review was conducted using data and information provided by Horizon and publically available information. These included:

- Horizon Utilities 2013 Asset Condition Assessment (Kinectrics Inc., 2013)
- Asset data including asset age, description, and asset condition for each of the asset classes
- Answers to KPMG's questionnaire requesting clarification or additional information
- Asset Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010)
- Answers obtained through interviews with Horizon representatives

The approach taken by KPMG to assess the Kinectrics results was to independently recreate the calculations using the data and information presented to KPMG by Horizon and the Kinectrics methodology contained in their report. The intermediate and final outcomes were compared to the published Kinectrics results. The comparisons that were completed included:

- Total population of individual asset classes
- Health indices for each asset class
- Effective ages for each asset class
- Flagged-for-Action profiles for each asset class
- Estimated 20 year monetary capital investment using Horizon supplied standard unit costs

In addition to comparing Kinectrics calculated results with KPMG's results, KPMG also conducted additional tests to confirm the reasonability of Kinectrics' recommendations. The additional tests included:

- Comparison of the calculated effective age distributions against the chronological age distributions for the different asset classes to determine reasonability of the methodology for determining effective age
- Comparison of estimated capital investment required for the Kinectrics' Flagged-for-Action plan and an alternative plan generated from the useful asset life ranges contained in the Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010)

5 Assurance Review Results

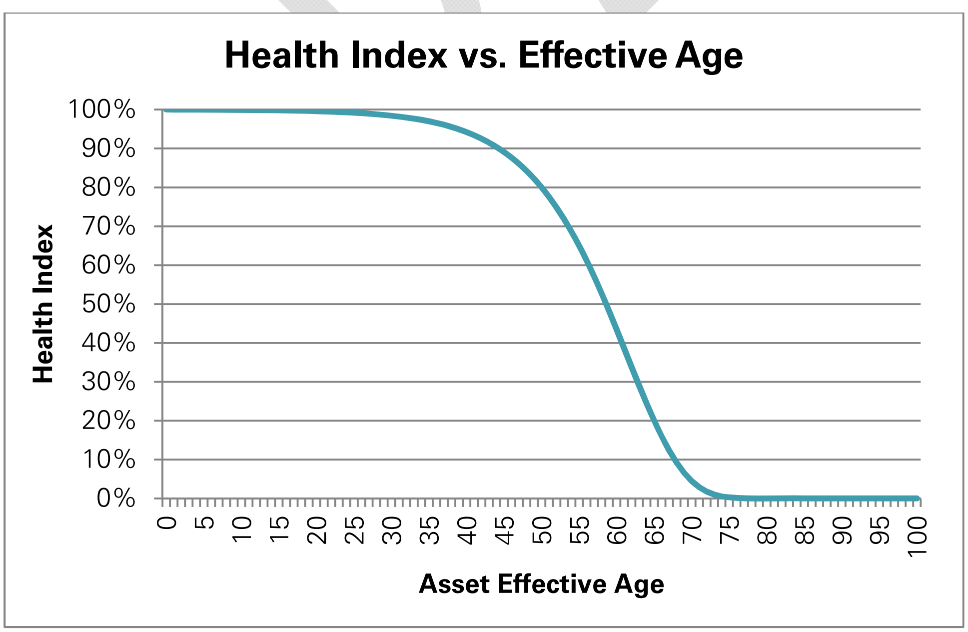
5.1 Kinectrics Methodology

Kinectrics adopted a probabilistic approach to identify expected failures and probable number of units for replacement based on asset condition as represented by the asset health index score. The approach is non-deterministic (i.e. resultant actions are not linked to any specific assets but, rather applies to the asset group as a whole) for reactively replaced assets and deterministic (i.e. actions are directly linked to specific assets) for proactively replaced asset classes. Kinectrics' high-level methodology is shown in Figure 1 below.

Figure 1: Methodology for Determining Flagged-for-Action Plans

The formula used to calculate the health index for each asset class was unique depending on available asset condition data. The health index for each asset was calculated using weighted averages of known asset age and known asset condition parameters and their associated weighting factors. The health index was then used to determine the asset effective age as demonstrated in Figure 2 below using the appropriate survival curve determined jointly by Kinectrics and Horizon for that asset class.

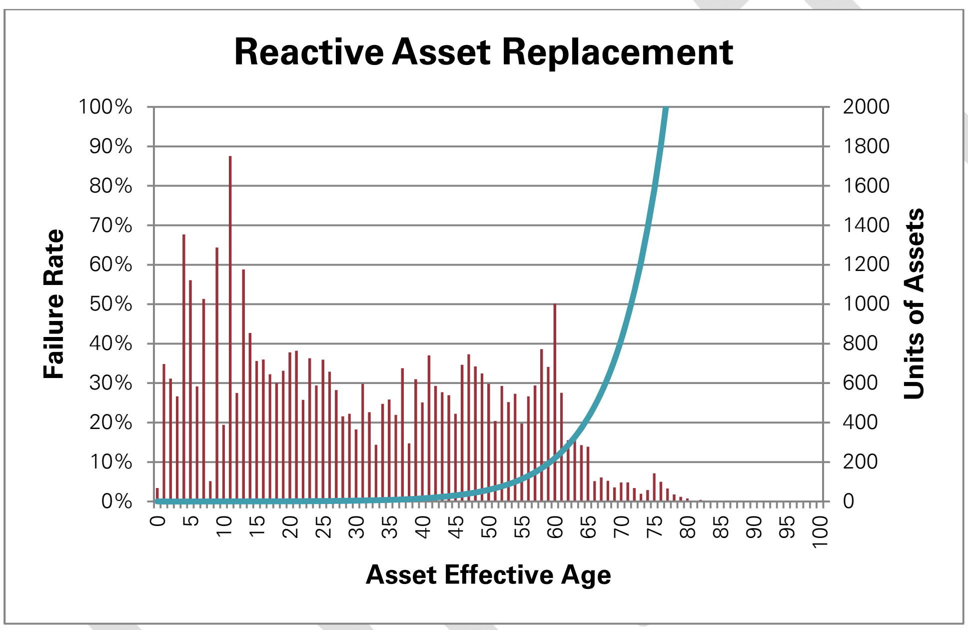
Figure 2: Determining Effective Age from Health Index



This method takes into account known asset condition in order to modify the actual chronological age into an effective age prior to calculating the probability of failure. For example, an asset that is well maintained would have an effective age that is lower than its actual chronological age indicating a lower probability of failure. Conversely, an asset that is overloaded or that is situated in adverse conditions would be de-rated to have a higher effective age as compared to its chronological age leading to a higher probability of failure. This method of predicting asset failure is a more representative method for predicting probability of failure over using only the chronological age.

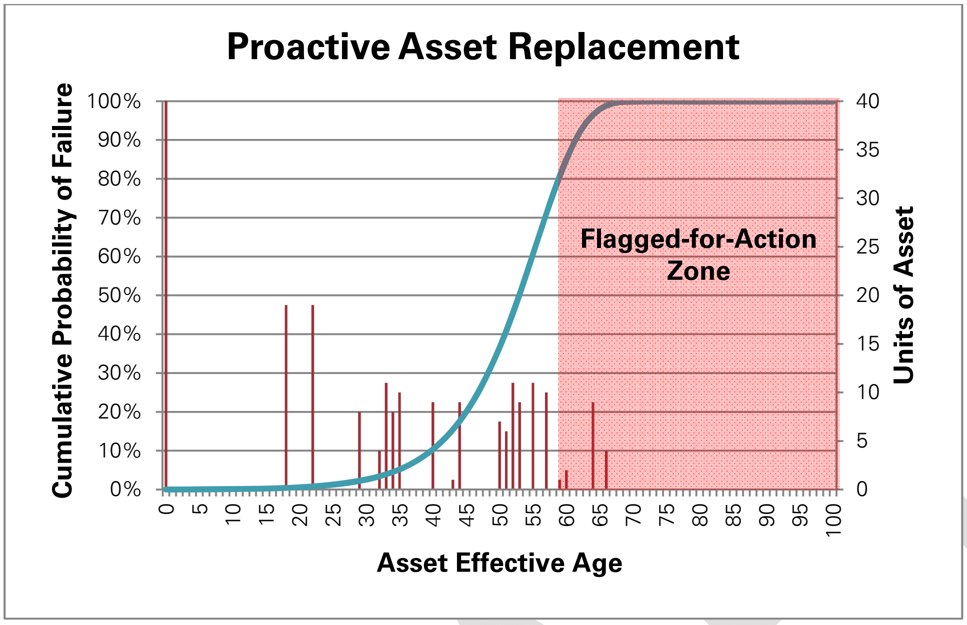
Once the effective age distribution of an asset class is known, it is used to determine probable failure rates. For reactively replaced assets, the effective age distribution is mapped against the assigned failure rate curve for each asset class to determine the quantity of assets projected to fail over the next twenty years (see Figure 3 below).

Figure 3: Flagged-for-Action Methodology used for Reactively Replaced Assets



For proactively replaced assets, the effective age is mapped against the cumulative probability of failure curve and assets with an effective age that returns a cumulative probability of failure of greater than or equal to 80% are flagged for replacement. Figure 4 represents the methodology used to flag proactively replaced assets.

Figure 4: Flagged-for-Action Methodology used for Proactively Replaced Assets



The twenty year Flagged-for-Action plan is developed by progressively advancing the effective age of the assets yearly and any assets flagged for replacement are subtracted from the population and replaced with new assets for that year.

The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in actuary science and by other utilities. The inclusion of asset condition in these calculations provides a more sophisticated approach than using just chronological age alone. Kinectrics also employed different predictive models for run to failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiation approach is more advanced than what is currently in use at most other utilities and in practice should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

KPMG's assurance review of Kinectrics methodologies for calculating Flagged-for-Action plans for both reactively and proactively replaced asset classes confirmed that the respective methodologies were consistently applied across the asset classes. The selected methodology for estimating asset replacement for sustainment purposes is deemed to be reasonable and is an accepted practice within the utilities industry.

5.2 Kinectrics Analytics

The results of the assurance review on the analytics used to determine the Kinectrics results are shown in the following sections.

5.2.1 Asset Populations Comparison

The total population of the individual asset classes were summed and compared to the population cited by Kinectrics in their report. Table 2 summarizes the results of the population comparison.

Table 2: Comparison of Asset Population

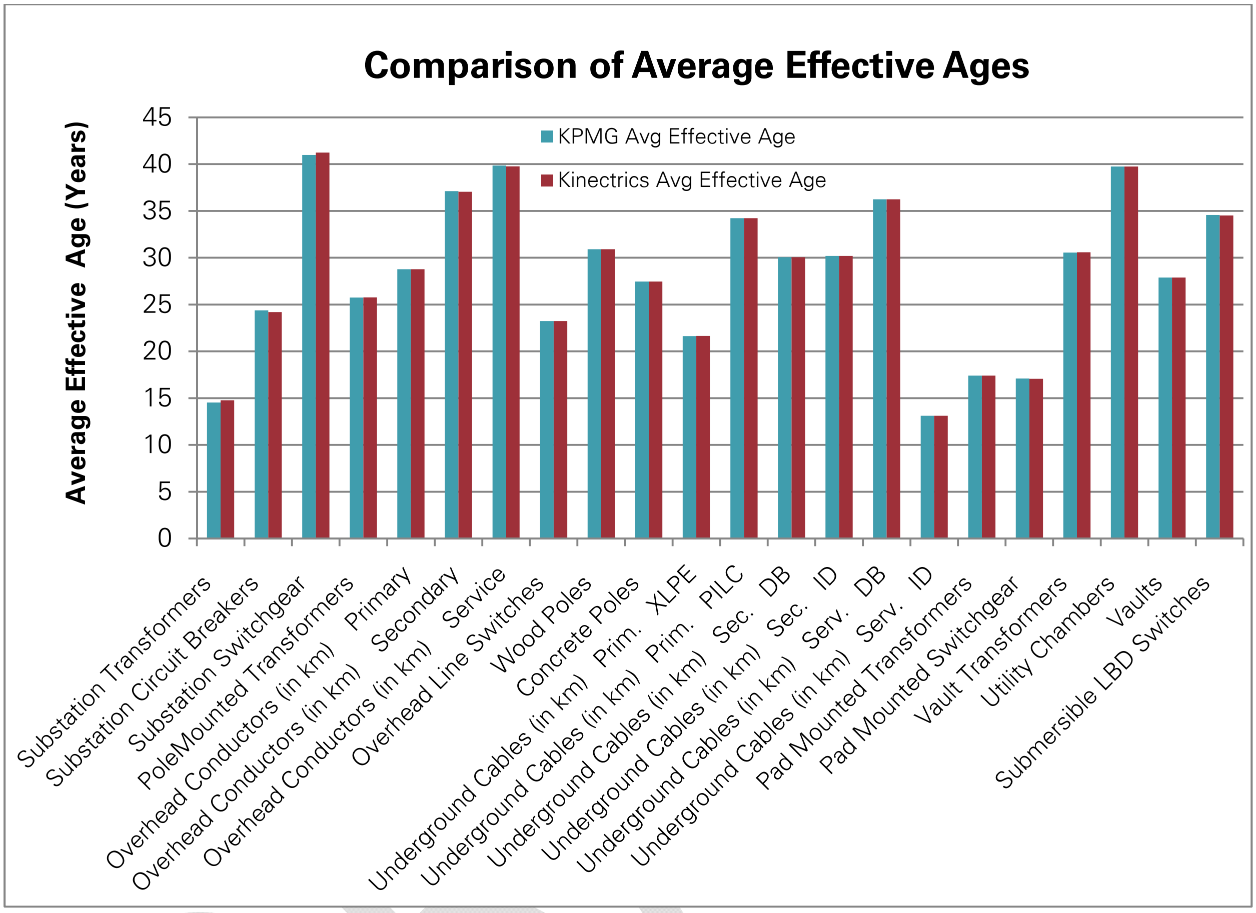
Asset Class		KPMG Total Asset Population	Kinectrics Total Asset Population	Population Difference	Percentage Population Difference
Substation Transformers		70	70	0	0.0%
Substation Circuit Breakers		279	279	0	0.0%
Substation Switchgear		37	37	0	0.0%
Pole Mounted Transformers		12886	12886	0	0.0%
Overhead Conductors (in km)	Primary	3386	3386	0	0.0%
Overhead Conductors (in km)	Secondary	2196	2196	0	0.0%
Overhead Conductors (in km)	Service	1897	1897	0	0.0%
Overhead Line Switches		711	712	-1	-0.1%
Wood Poles		42037	42037	0	0.0%
Concrete Poles		9761	9761	0	0.0%
Underground Cables (in km)	Prim. XLPE	2060	2060	0	0.0%
Underground Cables (in km)	Prim. PILC	1532	1532	0	0.0%
Underground Cables (in km)	Sec. DB	757	757	0	0.0%
Underground Cables (in km)	Sec. ID	533	533	0	0.0%
Underground Cables (in km)	Serv. DB	447	447	0	0.0%
Underground Cables (in km)	Serv. ID	588	588	0	0.0%
Pad Mounted Transformers		5906	5906	0	0.0%
Pad Mounted Switchgear		186	186	0	0.0%
Vault Transformers		4169	4169	0	0.0%
Utility Chambers		2075	2075	0	0.0%
Vaults		3413	3413	0	0.0%
Submersible LBD Switches		117	117	0	0.0%

With one exception, the asset population in each asset class matches with Kinectrics' published results. The only difference observed is with the Overhead Line Switches where there is a 1 unit difference; however the overall impact to the analysis is immaterial. This comparison confirms that the data population is identical to the data population used by Kinectrics in their analysis.

5.2.2 Health Indices and Effective Age Comparisons

Health index calculations were recreated independently by KPMG using Kinectrics' published methodology found in their report (KPMG was not privy to Kinectrics' proprietary calculation models). The calculated health indices were then used to determine the effective ages. When the calculated health indices were compared to Kinectrics results, there were no significant differences identified and the calculated values were then used to determine the effective ages for each asset class. The results of the effective ages are summarized in Figure 5 below.

Figure 5: Comparison of Average Effective Ages

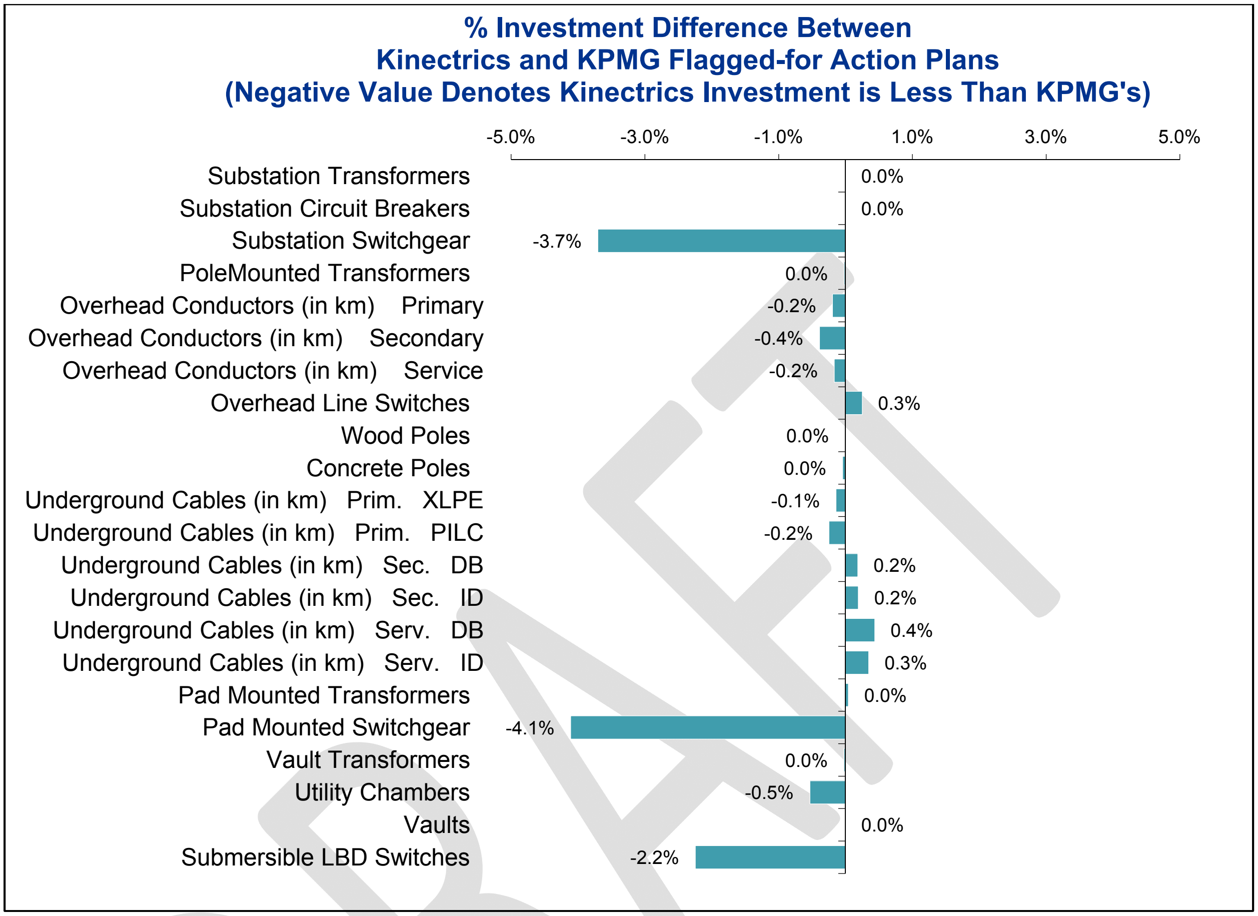


As evidenced by Figure 5 , the average effective age distributions for the different asset classes are virtually identical for both Kinectrics calculations and KPMG's calculations. Minor differences were observed for the proactively replaced assets (Substation Transformers, Substation Circuit Breakers and Substation Switchgear) but as the subsequent Flagged-for-Action analysis shows, these minor differences did not result in material differences in the Flagged-for-Action plans for these asset classes.

5.2.3 Flagged-for-Action Comparisons

Based on KPMG's calculated effective age distribution for each asset class, the Flagged-for-Action plans for the next twenty years were calculated based on whether the asset was deemed to be proactively replaced or reactively replaced. A detailed summary of the units Flagged-for-Action are shown in Appendix 1. The differences in the Flagged-for-Action plans are minor and are deemed to be immaterial. A summary of the percentage differences is shown in Figure 6, below.

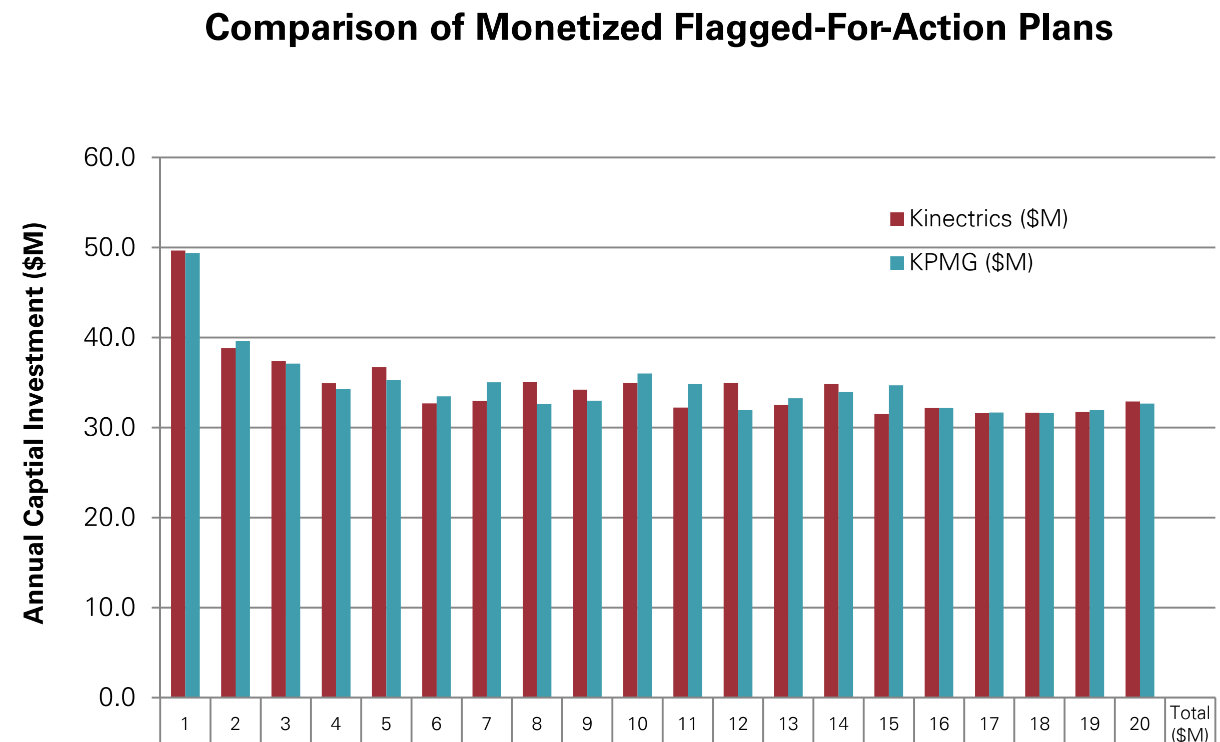
Figure 6: Percentage Difference in Flagged-for-Action Plans between Kinectrics and KPMG



The most significant percentage differences are in the Substation Switchgear, the Pad Mounted Switchgear and the Submersible LBD Switches asset classes. These asset classes have a small number of units in their population (less than 100 in each instance) and any small discrepancies in numeric values result in larger percentage differences when compared to other asset classes. The numerical differences can be found in Appendix 1. The impact of these differences to the Flagged-for-Action plan at the distribution network level over twenty years is immaterial.

Flagged-for-Action unit plans were monetized using standard unit costs in order to effectively allow comparison of the business impact of the identified differences. The standard unit costs used were provided by Horizon for each asset class. The resultant estimated investment over twenty years for the respective plans is shown in Figure 7 below.

Figure 7: Comparison of Monetized Flagged-for-Action Plans



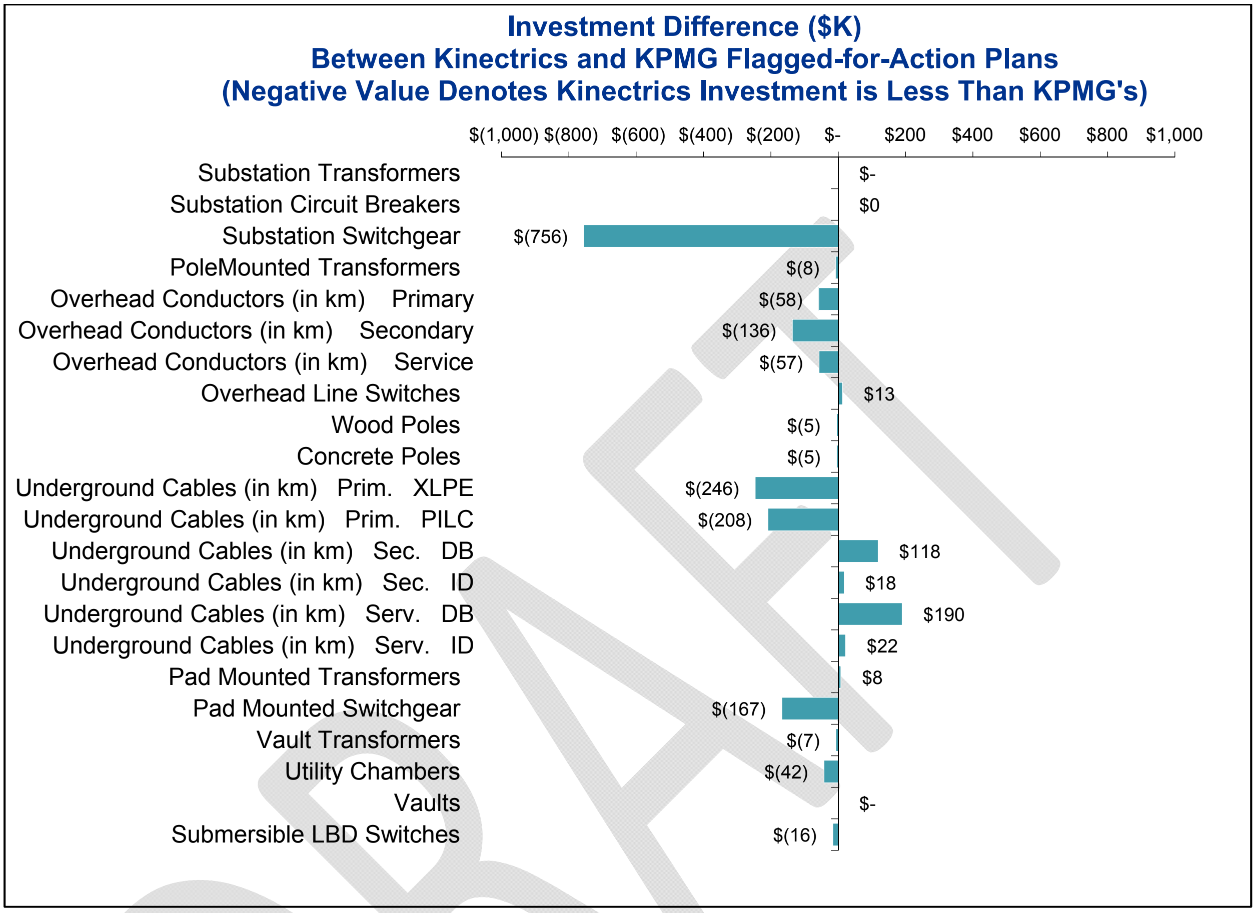
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
KPMG ($M)	49.4	39.6	37.1	34.3	35.3	33.5	35.0	32.6	33.0	36.0	34.9	32.0	33.3	34.0	34.7	32.2	31.7	31.6	31.9	32.7	694.8

Years into the Future

This monetized plan is meant to serve as a normalized comparison in dollar terms between the two respective Flagged-for-Action plans and it is not meant to be used as the definitive guide for Horizon's future capital investments. The two plans returned very similar total investment values over the twenty year span supporting the reasonableness of the calculations presented in the Kinectrics report. The total investment differs by only $1.1 million over twenty years or 0.02% for the period. The estimated monetary differences for each asset class are summarized in Figure 8, below.

When comparing Kinectrics and KPMG results for the first five years of the monetized investment plan, the total investment portfolio difference found during this time period was $1.8 million or 0.09% of the five year plan. This investment difference was found to be primarily caused by the Substation Switchgear asset class. Due to the relatively low number of Substation Switchgear assets involved, the different values returned by the respective lookup methods employed by Kinectrics and KPMG resulted in slight variations in the timing of the Flagged-for-Action profile (See Appendix 1 for details). This variation was deemed to be insignificant to the overall five year Flagged-for-Action plan.

Figure 8: Comparison of Estimated Value of Flagged-for-Action Plans between Kinectrics and KPMG



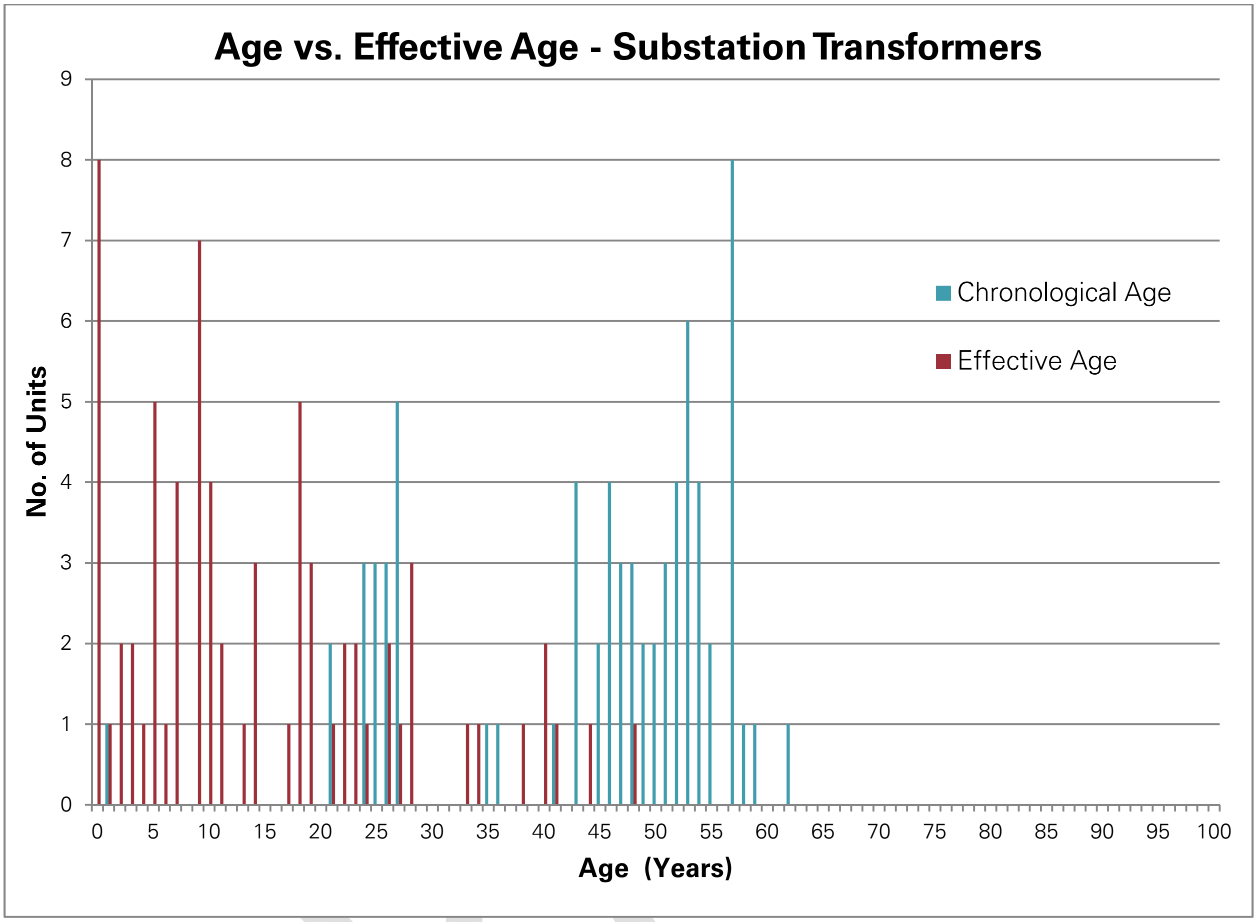
The results of the analysis show that Kinectrics' resulting end calculations can be replicated independently within a very small margin of error. It is KPMG's opinion that Kinectrics has accurately applied their published methodology and formulas contained in their report against the Horizon supplied asset data set.

5.3 Tests for Reasonableness

5.3.1 Comparison of Effective Age against Chronological Age

In order to test whether the health indices and the associated effective ages of assets were reasonable, the calculated effective age was compared to the chronological age in terms of age distribution and overall average age for each of the asset classes. The age distribution comparison test was meant to reveal whether the incorporation of the asset condition parameters played a major role in altering the chronological age in a material way. Figure 9 below is an example of the comparison conducted for each asset class.

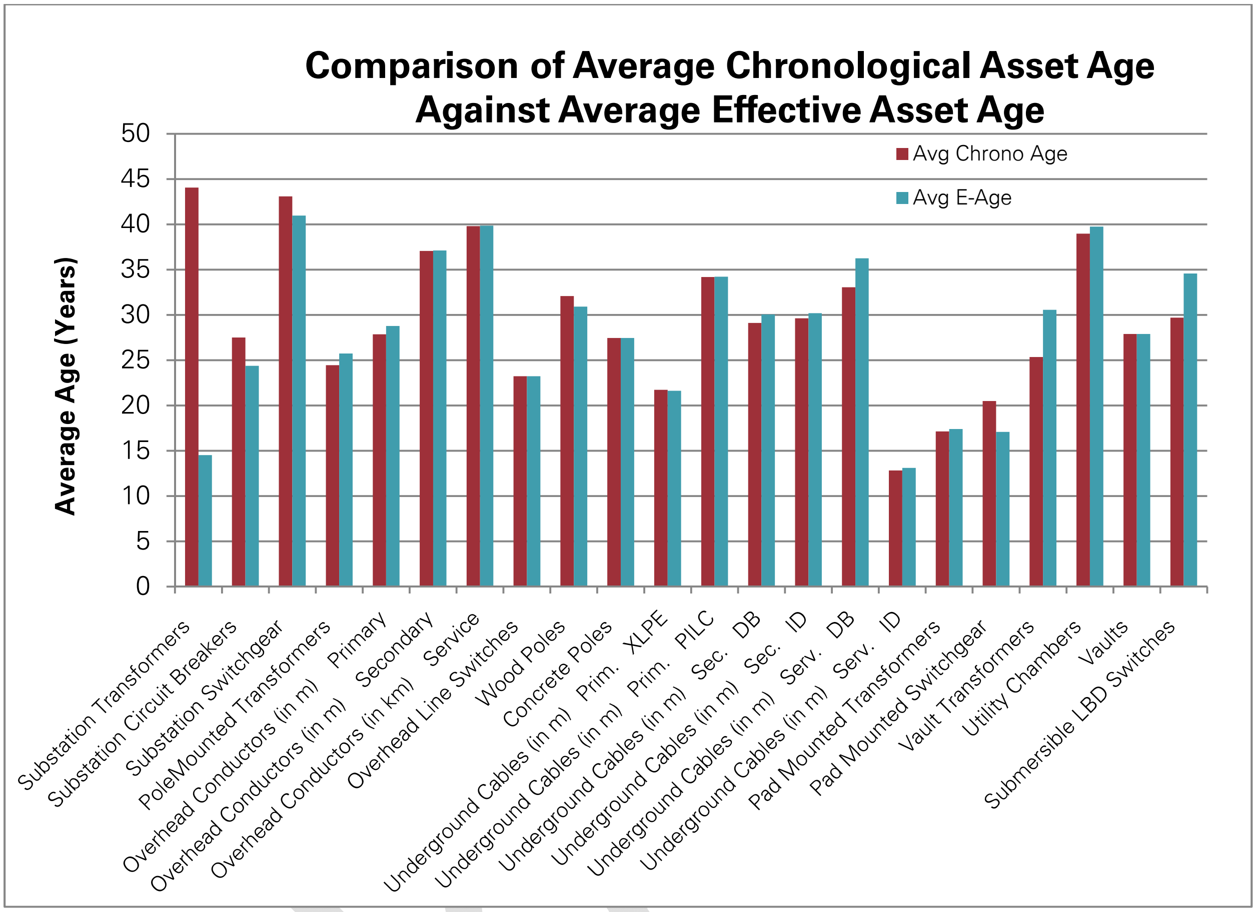
Figure 9: Example of Chronological Age versus Effective Age Comparison



The conversion of chronological age to effective age as a result of having asset condition parameters applied did shift the age distribution significantly for some asset classes. The differences between the average effective ages and the average chronological ages can be seen in Figure 10 below. The most significant shift is in the Substation Transformer asset class as the average effective age is significantly below the average chronological age. This phenomenon, as explained by Horizon representatives is the result of having significant maintenance and testing programs in place for this relatively old asset class to ensure their performance and reliability as these assets are key core components of the distribution system.

This test revealed that the use of effective ages to calculate the Flagged-for-Action plans would generate different end results than plans generated from chronological ages. However, the Flagged-for-Action differences in all the asset classes with the exception of the Substation Transformers would be reasonably close between the two different age profiles. For the Substation Transformers, the Flagged-for-Action plan using the assets' effective ages would significantly understate the number of units to be Flagged-for-Action when compared with a plan generated by the use of chronological age alone. Using effective ages to determine the Flagged-for-Action plan was deemed to be more reflective of actual asset conditions than using just chronological age.

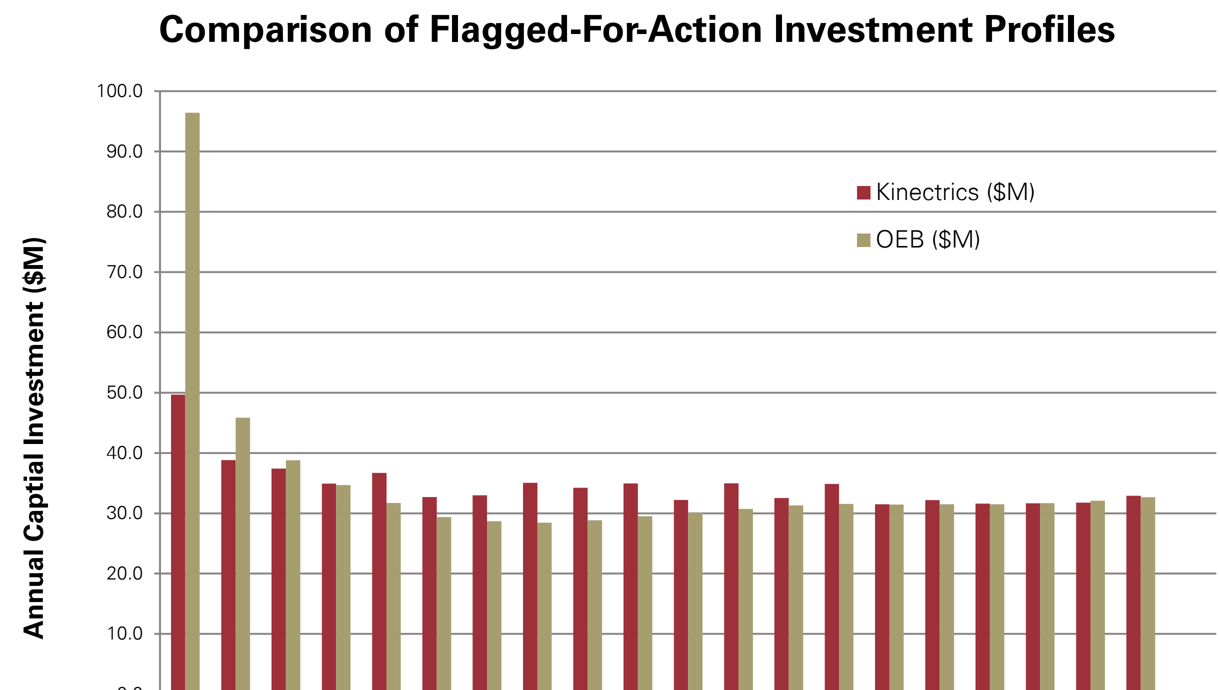
Figure 10: Comparison of Average Effective Ages against Average Chronological Ages



5.3.2 Comparison of Kinectrics' Flagged-for-Action Plan against Accepted Asset Life Standards

The final test to determine reasonability of the Kinectrics Flagged-for-Action plan was to compare the total plan against published and accepted industry standards for asset life expectancies. The standard life expectancies chosen for comparison were those published in the Asset Depreciation Study for the Ontario Energy Board (see Appendix 2). The published Typical Useful Life (TUL) and the Maximum Useful Life (MUL) were used to estimate the failure curve (f_t) and the cumulative probability of failure (P_f) for use in projecting asset replacements. Based on interpretation of the OEB report, the TUL was assigned 20% P_f, and the MUL was assigned 85% P_f. Failure curves were subsequently developed using the published TUL and MUL figures; the only exception was for the Submersible LBD Switches for which figures were not available in the OEB report. For this asset class, the UG Vault switch values for TUL and MUL were used as a proxy. Flagged-for-Action plans for each asset class were then calculated using the chronological age as the OEB useful lives data was developed for use with chronological asset age. The comparison of the normalized monetary results for the two different Flagged-for-Action plans is shown in Figure 11 below.

Figure 11: Comparison of Kinectrics Flagged-for-Action Plan versus Plan Generated from OEB Data



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
OEB ($M)	96.4	45.9	38.8	34.7	31.7	29.4	28.7	28.4	28.9	29.5	30.1	30.7	31.3	31.6	31.4	31.5	31.5	31.7	32.1	32.7	706.9

The total estimated investment for the two different plans over twenty years is within 2% of each other. The results calculated from the OEB life expectancies are heavily front-end loaded suggesting that model assesses Horizon's asset base as being closer to end of life than Kinectrics effective age model. This comparison substantiates the life curves used by Kinectrics in their models are reasonably close to industry accepted useful life data. The Kinectrics' life curves have longer average expected life-spans for some of the asset classes leading to fewer asset investments identified for the immediate short term. When compared to the OEB results, the Kinectrics Flagged-for-Action plan is not overstated and is reasonably within the industry accepted asset replacement or refurbishment practices for distribution utilities in Ontario.

6 Conclusions

Based on an independent assurance review of the methodology and analytics used in the Kinectrics report, it is KPMG's opinion that the approach used to arrive at the presented results is in line with industry practice and generally accepted methodologies. KPMG is of the opinion that the presented methodology has been appropriately and consistently applied against the Horizon supplied asset data in order to derive the final Flagged-for-Action plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been independently validated by KPMG to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations.

Appendix 1 Comparison of Twenty Year Flagged-for-Action Plans

Assets Class	Source	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total
Substation Transformers	Kinectrics	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	2	5
Substation Transformers	KPMG	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	1	2	5
Substation Circuit Breakers	Kinectrics	16	0	10	0	11	0	9	0	17	0	7	0	0	0	0	9	1	0	0	9	89
Substation Circuit Breakers	KPMG	16	0	10	0	11	0	9	11	6	7	0	0	0	0	0	9	1	0	0	9	89
Substation Switchgear	Kinectrics	1	0	1	1	4	0	0	4	2	4	0	4	1	4	0	0	0	0	0	0	26
Substation Switchgear	KPMG	0	1	1	0	2	1	3	0	1	5	4	0	2	3	4	0	0	0	0	0	27
PoleMounted Transformers	Kinectrics	593	277	232	218	215	217	220	223	226	228	229	229	230	230	231	234	238	244	252	262	5028
PoleMounted Transformers	KPMG	594	277	232	218	215	217	220	223	226	228	229	229	230	230	232	234	238	244	252	262	5029
Overhead Conductors (in km) Primary	Kinectrics	53	45	40	37	34	32	31	30	29	30	30	31	32	32	32	33	33	33	33	34	684
Overhead Conductors (in km) Primary	KPMG	53	46	41	37	34	32	31	30	29	30	30	31	32	32	33	33	33	33	33	34	685
Overhead Conductors (in km) Secondary	Kinectrics	86	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	843
Overhead Conductors (in km) Secondary	KPMG	87	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	846
Overhead Conductors (in km) Service	Kinectrics	97	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	32	30	28	27	809
Overhead Conductors (in km) Service	KPMG	99	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	31	30	28	27	810
Overhead Line Switches	Kinectrics	31	26	23	22	20	20	19	18	19	18	18	18	17	17	17	17	16	17	17	17	387
Overhead Line Switches	KPMG	31	26	23	22	21	20	19	19	18	18	18	17	17	17	17	17	17	17	17	17	386
Wood Poles	Kinectrics	1509	1103	1011	967	935	905	876	845	814	782	752	724	699	678	662	648	637	627	619	611	16404
Wood Poles	KPMG	1509	1103	1011	968	935	906	876	845	814	782	752	724	699	678	661	648	637	627	619	611	16405
Concrete Poles	Kinectrics	97	98	100	101	103	104	105	107	108	109	110	111	112	114	115	118	119	121	123	126	2201
Concrete Poles	KPMG	97	98	100	101	103	104	105	106	108	109	110	111	112	114	116	117	119	121	124	126	2202
Underground Cables (in km) Prim. XLPE	Kinectrics	126	103	96	91	88	85	83	80	78	76	74	72	71	70	69	68	67	66	66	66	1595
Underground Cables (in km) Prim. XLPE	KPMG	127	103	95	91	88	85	83	80	78	76	74	73	71	70	69	68	67	67	66	66	1597
Underground Cables (in km) Prim. PILC	Kinectrics	11	11	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	339
Underground Cables (in km) Prim. PILC	KPMG	12	12	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	340
Underground Cables (in km) Sec. DB	Kinectrics	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	519
Underground Cables (in km) Sec. DB	KPMG	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	518
Underground Cables (in km) Sec. ID	Kinectrics	21	21	21	20	20	19	19	19	18	18	18	18	17	17	17	17	17	16	16	16	365
Underground Cables (in km) Sec. ID	KPMG	21	21	20	20	20	19	19	19	18	18	18	18	17	17	17	17	16	16	16	16	364
Underground Cables (in km) Serv. DB	Kinectrics	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	352
Underground Cables (in km) Serv. DB	KPMG	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	350
Underground Cables (in km) Serv. ID	Kinectrics	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15	257
Underground Cables (in km) Serv. ID	KPMG	10	11	11	11	11	12	12	12	12	13	13	13	13	14	14	14	14	15	15	15	256
Pad Mounted Transformers	Kinectrics	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Transformers	KPMG	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Switchgear	Kinectrics	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	70
Pad Mounted Switchgear	KPMG	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	73
Vault Transformers	Kinectrics	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	162	156	150	144	139	4250
Vault Transformers	KPMG	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	163	156	150	144	139	4251
Utility Chambers	Kinectrics	12	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	23	24	25	26	373
Utility Chambers	KPMG	13	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	24	24	25	26	375
Vaults	Kinectrics	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Vaults	KPMG	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Submersible LBD Switches	Kinectrics	14	8	7	6	5	5	5	4	4	4	3	3	3	3	2	2	2	2	2	3	87
Submersible LBD Switches	KPMG	14	8	7	6	5	5	5	4	4	4	4	3	3	3	3	3	2	2	2	2	89

Appendix 2 Summary of OEB's Asset Useful Lives

F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS Category | Component | Type			USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
OH	1	Fully Dressed Wood Poles	Cross Arm	Wood	20	40	55						
OH	1	Fully Dressed Wood Poles	Cross Arm	Steel	30	70	95						
OH	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
OH	2	Fully Dressed Concrete Poles	Cross Arm	Wood	20	40	55						
OH	2	Fully Dressed Concrete Poles	Cross Arm	Steel	30	70	95						
OH	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
OH	3	Fully Dressed Steel Poles	Cross Arm	Wood	20	40	55						
OH	3	Fully Dressed Steel Poles	Cross Arm	Steel	30	70	95						
OH	4	OH Line Switch			30	45	55	L	L	L	L	M	L
OH	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
OH	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
OH	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
OH	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
OH	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
OH	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
OH	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
TS & MS	12	Power Transformers	Bushing		10	20	30						
TS & MS	12	Power Transformers	Tap Changer		20	30	60						
TS & MS	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
TS & MS	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
TS & MS	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
TS & MS	15	Station DC System	Battery bank		10	15	15						
TS & MS	15	Station DC System	Charger		20	20	30						
TS & MS	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
TS & MS	16	Station Metal Clad Switchgear	Removable Breaker		25	40	60						
TS & MS	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
TS & MS	18	Station Switch			30	50	60	M	L	M	M	M	L

* OH = Overhead Lines System TS & MS = Transformer and Municipal Stations
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS Category | Component | Type		USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
			Protector	20	35	40						
	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
	36	UG Foundations		35	55	70	M	NI	M	L	L	M
	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
			Roof	20	30	45						
	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
	40	Ducts		30	50	85	H	NI	M	NI	NI	L
	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
	42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H

* TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

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Kinectrics Inc. (2013). *Horizon Utilities 2013 Asset Condition Assessment.* Toronto: Kinectrics Inc.

Kinectrics Inc. Report No: K-418033-RA-001-R000. (2010). *Asset Depreciation Study for the Ontario Energy Board.* Toronto: Kinectrics Inc.

Author Biography

Julius Pataky, P.Eng. MBA

Julius Pataky is a KPMG Partner with 35 years progressive industry and consulting experience in the energy industry, with demonstrated leadership skills in asset management, building effective teams, leading transformation and bringing innovation to the business. Julius joined KPMG after having led innovative asset management solutions at BC Transmission and BC Hydro. In his roles as VP, Asset Investment, he brought the PAS 55 framework into organization's operating model, led the development of innovative asset analytic and planning solutions and gained regulatory approval for increased capital investment. He not only had accountability for developing the Capital Plans for transmission and distribution but also developing the regulatory justification for these capital investments. During this period, investments in the grid for the utility had grown from under $200M/yr to $1.3B/yr. He acted as company lead in communication of the need for increase in grid investment with stakeholders and the public. He also led numerous consultation efforts to gain acceptance of contentious projects with municipal leaders and landowners.

David Cheng, P.Eng.

David Cheng is a Senior Manager in KPMG LLP's Advisory Services Practice and is a member of the firm's Asset Management practice. Over his career, David has successfully transformed numerous businesses through his knowledge of asset management, operations management, business process improvement, information management and project and program management. He has led a diverse portfolio of projects as a consultant for private and public sector organizations plus he has years of executive and managerial experience leading teams in the utilities, aerospace, high-technology, healthcare and consumer products industries. As a former Manager of Asset Data and Information at BC Hydro and BC Transmission Corporation (BCTC), David was responsible for the development of asset analytic algorithms used to support capital investment justifications contained within the rate application submissions to BC Utilities Commission (BCUC). The asset analytics deployed probabilistic asset health based analysis to determine projected asset replacement requirements based on asset condition and asset demographics.

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Horizon Utilities Corporation

Assurance Review of Kinectrics' Asset Condition Assessment Report

Jan 23, 2014

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Version Control

Version	Date	By	Description
0.9	Dec 18, 2013	David Cheng	Original Draft for discussion
1.0	Jan 21, 2014	David Cheng	Incorporated Horizon feedback
1.1	Jan 23, 2014	David Cheng	Incorporated additional Horizon feedback

Glossary

Chronological Age	age of the asset expressed in years since its installation
Health Index	condition of the asset expressed as a percentage score between 0 and 100% with 100% representing an asset that is in new condition
Proactive Replacement	a strategy that will flag assets for action based on the capability of handling a pre-defined stress level, typically resulting in Flagged-for-Action prior to the physical end of life.
Reactive Replacement	a strategy that flags assets for action based on the failure rate of the assets
Flagged-for-Action	a state that identifies assets to be considered for replacement or significant refurbishment

Contents

1 Executive Summary

Kinectrics Inc. ("Kinectrics") was retained by Horizon between 2012 and 2013 to conduct an assessment on Horizon's distribution assets with the goal of identifying future asset replacement or refurbishment needs in order to sustain the existing assets. Kinectrics findings and recommendations were delivered in their final report dated November 27, 2013 (Kinectrics Inc., 2013).

Based on an independent assurance review of the methodology and analytics used in the Kinectrics report titled "Horizon Utilities 2013 Asset Condition Assessment" (Kinectrics Inc., 2013), it is KPMG's opinion that the approach used to arrive at the presented results is in line with industry practice and generally accepted methodologies. KPMG is of the opinion that the presented methodology has been appropriately and consistently applied against the Horizon Utilities Corporation ("Horizon") supplied asset data in order to derive the final Flagged-for-Action (assets flagged for replacement or refurbishment) plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been independently validated by KPMG to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations.

KPMG was subsequently retained by Horizon as a third party to conduct an independent assurance review and provide an opinion on Kinectrics' methodology and the resultant findings and recommendations contained in their report. KPMG provided advisory services that consisted of inquiry, observation, analysis and comparison of Horizon-provided information. The findings relied on the completeness and accuracy of the information provided. KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG reviewed the methodology published by Kinectrics in their report and compared it with other methodologies used in utilities for predicting probabilistic life expectancy of assets in order to test the validity of the selected methodology used by Kinectrics. The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in other utilities and in actuary science. The inclusion of asset condition in these calculations provides a more sophisticated approach than that of using chronological age alone. Kinectrics also employed different predictive models for run-to-failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiated approach is more advanced than that which is currently in use at most other utilities and in theory should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

From the described methodology and from the original asset condition data set provided by Horizon to Kinectrics for their assessment, KPMG was successful in recreating independent analytical models to calculate the health indices, effective ages and Flagged-for-Action plans for the 22 distinct classes of assets (see Appendix 1) and comparing them with Kinectrics' published results.

The results calculated by Kinectrics and independently calculated by KPMG are within an acceptable and reasonable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. The numbers of units identified for replacement or refurbishment by the two respective models differ by less than 0.5% for 19 out of the 22 asset classes and the remaining 3 asset classes differ by no more than 4.5%. Using current standard unit costs provided by Horizon, the cumulative anticipated investment over twenty years is projected to be $693.7M for the Kinectrics model and $694.8M for that of KPMG. The projected twenty year difference is 0.02%; this difference is insignificant between the two models. Thus, it is KPMG's opinion that Kinectrics has consistently applied their methodology as published in their report using Horizon's asset data.

To test the reasonableness of the effective age calculations, the effective age distribution for each asset class was compared with the chronological age distribution to identify any potential anomalies in applying the asset condition ratings to the asset population. This test demonstrated relative consistency between chronological age and effective age distributions for 21 out of the 22 asset classes. The Substation Transformers asset class was the only exception found; its average effective age was found to be significantly below the average chronological age. The result of this age reduction is that this asset class would require less capital sustainment investments going forward than if the chronological age was the only criterion used. Using the effective age distribution, the investment impact would be understated when compared to using the chronological age distribution. This lower level of investment is reflected in the resultant Flagged-for-Action plan for Substation Transformers.

To further test the reasonableness of the Kinectrics results, a comparison of their Flagged-for-Action plan was made against an alternative plan generated from accepted asset life expectancies found in the Asset Depreciation Study for the Ontario Energy Board (OEB) report (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010). Using the published useful life expectancy data for the different asset classes found in the Asset Depreciation Study against the chronological ages of the assets, an alternative twenty year investment plan was created by KPMG. This alternative OEB-based investment plan was compared to the one created by Kinectrics. The twenty year investment plan based on the OEB data projected $706.9M required capital investment versus the $693.7M figure projected by Kinectrics. The marginal differences between these two models validated that Kinectrics' projections are within accepted industry norms and practices for asset replacements or refurbishments.

In conclusion, it is KPMG's opinion that the approach and the calculations used to arrive at the presented results in the Kinectrics report is in line with industry practice and generally accepted methodologies.

2 Introduction

In 2012, Horizon commissioned Kinectrics to conduct an asset condition assessment on Horizon's distribution assets with the goal of identifying future investments needed to sustain Horizon's existing asset base. Kinectrics' findings and recommendations have been published in the Horizon Utilities 2013 Asset Condition Assessment report (the "report") (Kinectrics Inc., 2013). Based on these recommendations, Horizon has prepared a Distribution System Plan ("DSP") that outlines the sustainment capital needed to maintain system performance over the next 20 years. The DSP will be submitted to the Ontario Energy Board ("OEB") in 2014 as part of Horizon's 2015 – 2019 rate application.

To support Horizon's rate application, KPMG was retained as an independent third-party, to complete an independent assurance review of the results contained in the Kinectrics report and provide a written opinion on the reasonableness of Kinectrics' findings and recommendations.

The procedures employed consisted solely of inquiry, observation, comparison and analysis of Horizon supplied information. The findings relied on the completeness and accuracy of the information as provided. KPMG expresses no opinion on financial results, internal control, data quality or other information.

KPMG recognizes this report may be called as evidence during the overall regulatory review process and as such KPMG may be needed to participate as an expert witness as prescribed by the OEB's procedural steps and timelines.

3 Assurance Review Scope

3.1 Scope

As an independent third party, KPMG completed the required data analysis to assess whether the results contained in the Kinectrics report are reasonable and acceptable. KPMG reviewed the methodology and analyses used by Kinectrics to generate the asset health indices, the effective ages and the resulting "Flagged-for-Action" plans for each of the asset classes shown in Table 1 below.

Table 1: Asset Classes in Scope

Asset Class	
Substation Transformers	
Substation Circuit Breakers	
Substation Switchgear	
Pole Mounted Transformers	
Overhead Conductors (in km)	Primary
Overhead Conductors (in km)	Secondary
Overhead Conductors (in km)	Service
Overhead Line Switches	
Wood Poles	
Concrete Poles	
Underground Cables (in km)	Prim. XLPE
Underground Cables (in km)	Prim. PILC
Underground Cables (in km)	Sec. DB
Underground Cables (in km)	Sec. ID
Underground Cables (in km)	Serv. DB
Underground Cables (in km)	Serv. ID
Pad Mounted Transformers	
Pad Mounted Switchgear	
Vault Transformers	
Utility Chambers	
Vaults	
Submersible LBD Switches	

The following inquiry, observation, comparison and analysis were undertaken in the assurance review process:

- Compared the methodology used by Kinectrics to determine the probabilistic remaining asset life expectancy against current methodologies employed by leading practitioners of asset management and against known published standards
- Using the methodology described in the Kinectrics report, created independent calculation engines for health indices, effective age and Flagged-for-Action plans in order to recreate the results contained in the Kinectrics report
- Using standard unit costs provided by Horizon, monetized the respective Flagged-for-Action plans generated by Kinectrics and KPMG in order to test the materiality differences of the two plans
- Compared KPMG calculations against Kinectrics calculations in order to test the validity of the Kinectrics results
- Created an alternative Flagged-for-Action model using the published expected life data contained in the Asset Depreciation Study for the Ontario Energy Board ("OEB") (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010) in order to test the reasonableness of Kinectrics' results with accepted industry standards

3.2 Not In Scope:

The following items were not in scope as part of the review process:

- Validation of the raw data quality (accuracy and completeness) used by Kinectrics to generate the results
- Validation of the selected failure curves used to estimate future asset failures
- Validation of actual asset conditions as expressed in the asset health indices
- Validation of the standard unit costs used in the determination of the Flagged-for-Action investment plans
- Interpretation of the Flagged-for-Action plans to future replacement or refurbishment investments

4 Assurance Review Methodology

The assurance review was conducted using data and information provided by Horizon and publically available information. These included:

- Horizon Utilities 2013 Asset Condition Assessment (Kinectrics Inc., 2013)
- Asset data including asset age, description, and asset condition for each of the asset classes
- Answers to KPMG's questionnaire requesting clarification or additional information
- Asset Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010)
- Answers obtained through interviews with Horizon representatives

The approach taken by KPMG to assess the Kinectrics results was to independently recreate the calculations using the data and information presented to KPMG by Horizon and the Kinectrics methodology contained in their report. The intermediate and final outcomes were compared to the published Kinectrics results. The comparisons that were completed included:

- Total population of individual asset classes
- Health indices for each asset class
- Effective ages for each asset class
- Flagged-for-Action profiles for each asset class
- Estimated 20 year monetary capital investment using Horizon supplied standard unit costs

In addition to comparing Kinectrics calculated results with KPMG's results, KPMG also conducted additional tests to confirm the reasonability of Kinectrics' recommendations. The additional tests included:

- Comparison of the calculated effective age distributions against the chronological age distributions for the different asset classes to determine reasonability of the methodology for determining effective age
- Comparison of estimated capital investment required for the Kinectrics' Flagged-for-Action plan and an alternative plan generated from the useful asset life ranges contained in the Depreciation Study for the Ontario Energy Board (Kinectrics Inc. Report No: K-418033-RA-001-R000, 2010)

5 Assurance Review Results

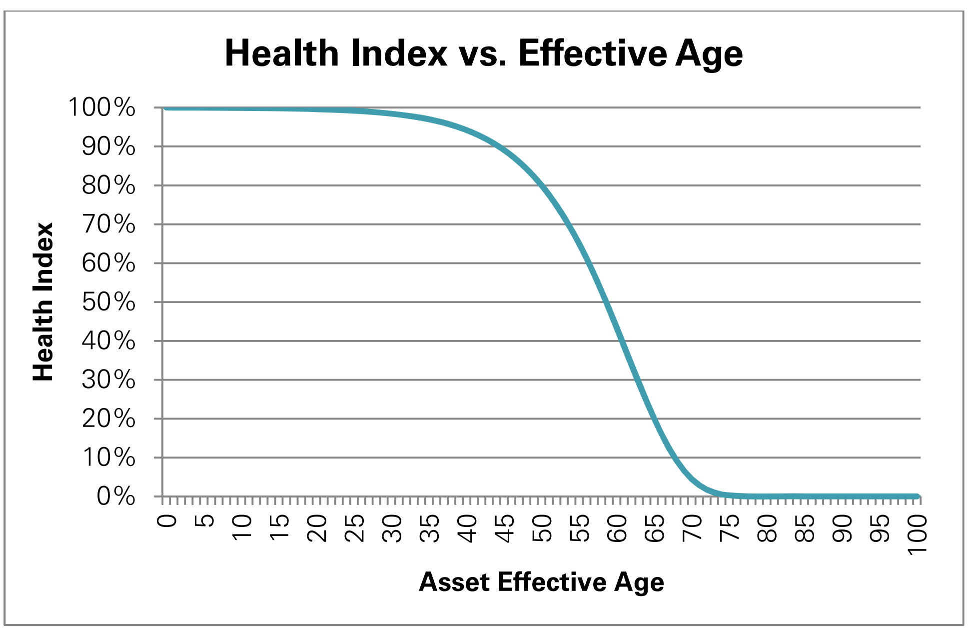
5.1 Kinectrics Methodology

Kinectrics adopted a probabilistic approach to identify expected failures and probable number of units for replacement based on asset condition as represented by the asset health index score. The approach is non-deterministic (i.e. resultant actions are not linked to any specific assets but, rather applies to the asset group as a whole) for reactively replaced assets and deterministic (i.e. actions are directly linked to specific assets) for proactively replaced asset classes. Kinectrics' high-level methodology is shown in Figure 1 below.

Figure 1: Methodology for Determining Flagged-for-Action Plans

The formula used to calculate the health index for each asset class was unique depending on available asset condition data. The health index for each asset was calculated using weighted averages of known asset age and known asset condition parameters and their associated weighting factors. The health index was then used to determine the asset effective age as demonstrated in Figure 2 below using the appropriate survival curve determined jointly by Kinectrics and Horizon for that asset class.

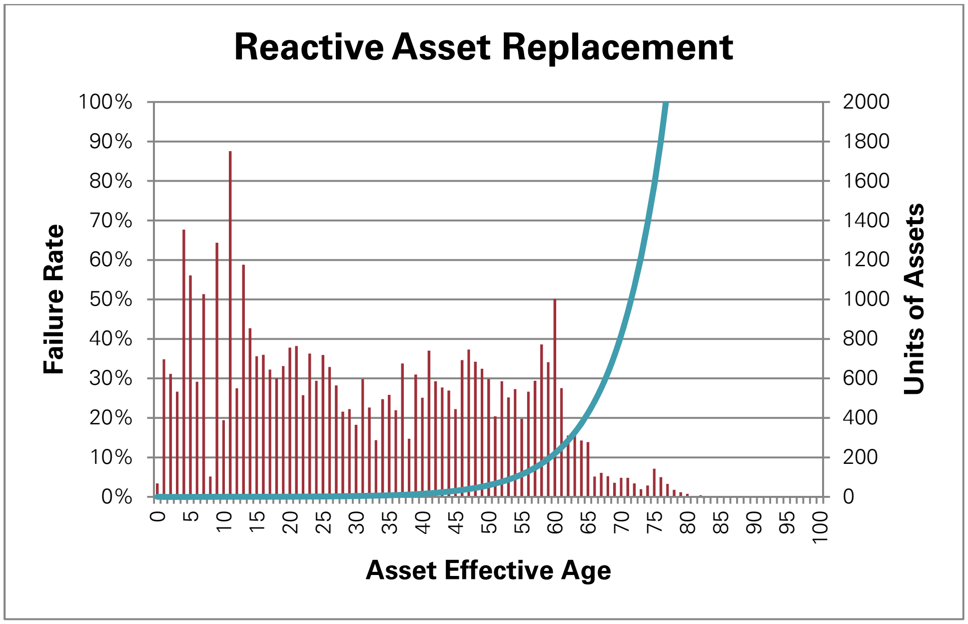
Figure 2: Determining Effective Age from Health Index



This method takes into account known asset condition in order to modify the actual chronological age into an effective age prior to calculating the probability of failure. For example, an asset that is well maintained would have an effective age that is lower than its actual chronological age indicating a lower probability of failure. Conversely, an asset that is overloaded or that is situated in adverse conditions would be de-rated to have a higher effective age as compared to its chronological age leading to a higher probability of failure. This method of predicting asset failure is a more representative method for predicting probability of failure over using only the chronological age.

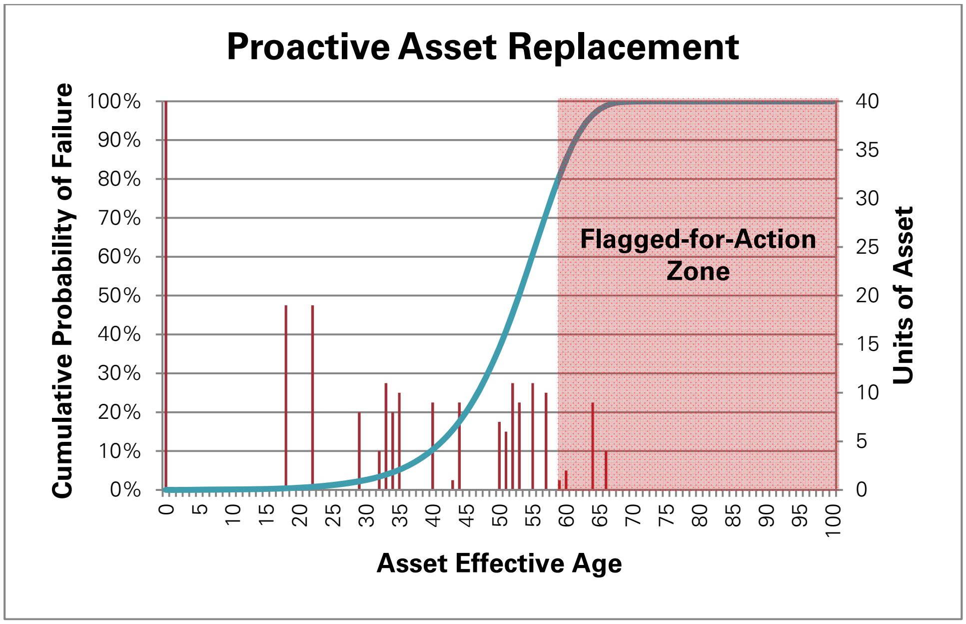
Once the effective age distribution of an asset class is known, it is used to determine probable failure rates. For reactively replaced assets, the effective age distribution is mapped against the assigned failure rate curve for each asset class to determine the quantity of assets projected to fail over the next twenty years (see Figure 3 below).

Figure 3: Flagged-for-Action Methodology used for Reactively Replaced Assets



For proactively replaced assets, the effective age is mapped against the cumulative probability of failure curve and assets with an effective age that returns a cumulative probability of failure of greater than or equal to 80% are flagged for replacement. Figure 4 represents the methodology used to flag proactively replaced assets.

Figure 4: Flagged-for-Action Methodology used for Proactively Replaced Assets



The twenty year Flagged-for-Action plan is developed by progressively advancing the effective age of the assets yearly and any assets flagged for replacement are subtracted from the population and replaced with new assets for that year.

The probabilistic approach used by Kinectrics to calculate remaining asset life based on asset condition and asset age is consistent with similar models used in actuary science and by other utilities. The inclusion of asset condition in these calculations provides a more sophisticated approach than using just chronological age alone. Kinectrics also employed different predictive models for run to failure assets (reactively replaced) and for assets that are replaced or rehabilitated before failure occurs (proactively managed assets). This differentiation approach is more advanced than what is currently in use at most other utilities and in practice should provide more appropriate modelling of remaining asset life for reactively replaced assets and for proactively managed assets.

KPMG's assurance review of Kinectrics methodologies for calculating Flagged-for-Action plans for both reactively and proactively replaced asset classes confirmed that the respective methodologies were consistently applied across the asset classes. The selected methodology for estimating asset replacement for sustainment purposes is deemed to be reasonable and is an accepted practice within the utilities industry.

5.2 Kinectrics Analytics

The results of the assurance review on the analytics used to determine the Kinectrics results are shown in the following sections.

5.2.1 Asset Populations Comparison

The total population of the individual asset classes were summed and compared to the population cited by Kinectrics in their report. Table 2 summarizes the results of the population comparison.

Table 2: Comparison of Asset Population

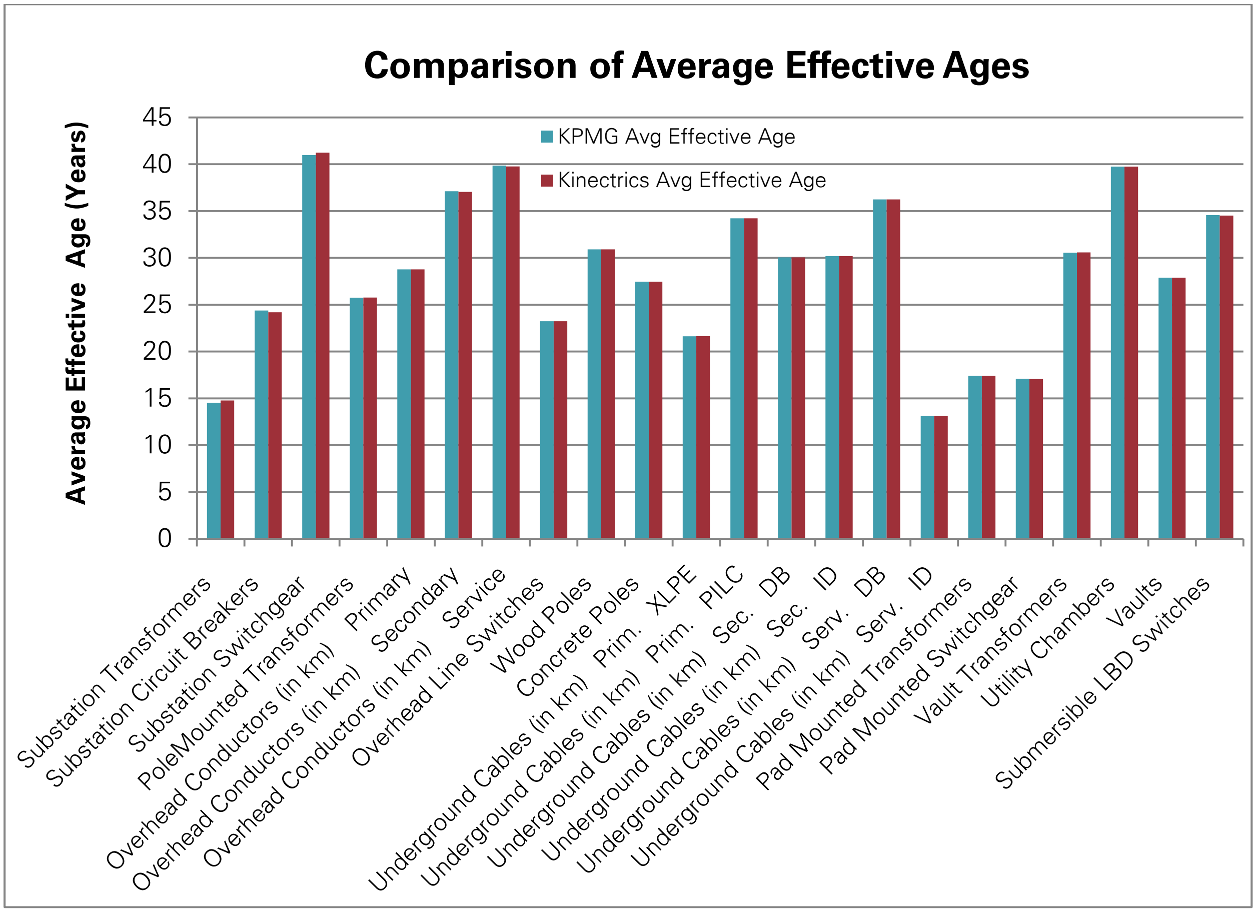
Asset Class		KPMG Total Asset Population	Kinectrics Total Asset Population	Population Difference	Percentage Population Difference
Substation Transformers		70	70	0	0.0%
Substation Circuit Breakers		279	279	0	0.0%
Substation Switchgear		37	37	0	0.0%
Pole Mounted Transformers		12886	12886	0	0.0%
Overhead Conductors (in km)	Primary	3386	3386	0	0.0%
Overhead Conductors (in km)	Secondary	2196	2196	0	0.0%
Overhead Conductors (in km)	Service	1897	1897	0	0.0%
Overhead Line Switches		711	712	-1	-0.1%
Wood Poles		42037	42037	0	0.0%
Concrete Poles		9761	9761	0	0.0%
Underground Cables (in km)	Prim. XLPE	2060	2060	0	0.0%
Underground Cables (in km)	Prim. PILC	1532	1532	0	0.0%
Underground Cables (in km)	Sec. DB	757	757	0	0.0%
Underground Cables (in km)	Sec. ID	533	533	0	0.0%
Underground Cables (in km)	Serv. DB	447	447	0	0.0%
Underground Cables (in km)	Serv. ID	588	588	0	0.0%
Pad Mounted Transformers		5906	5906	0	0.0%
Pad Mounted Switchgear		186	186	0	0.0%
Vault Transformers		4169	4169	0	0.0%
Utility Chambers		2075	2075	0	0.0%
Vaults		3413	3413	0	0.0%
Submersible LBD Switches		117	117	0	0.0%

With one exception, the asset population in each asset class matches with Kinectrics' published results. The only difference observed is with the Overhead Line Switches where there is a 1 unit difference; however the overall impact to the analysis is immaterial. This comparison confirms that the data population is identical to the data population used by Kinectrics in their analysis.

5.2.2 Health Indices and Effective Age Comparisons

Health index calculations were recreated independently by KPMG using Kinectrics' published methodology found in their report (KPMG was not privy to Kinectrics' proprietary calculation models). The calculated health indices were then used to determine the effective ages. When the calculated health indices were compared to Kinectrics results, there were no significant differences identified and the calculated values were then used to determine the effective ages for each asset class. The results of the effective ages are summarized in Figure 5 below.

Figure 5: Comparison of Average Effective Ages

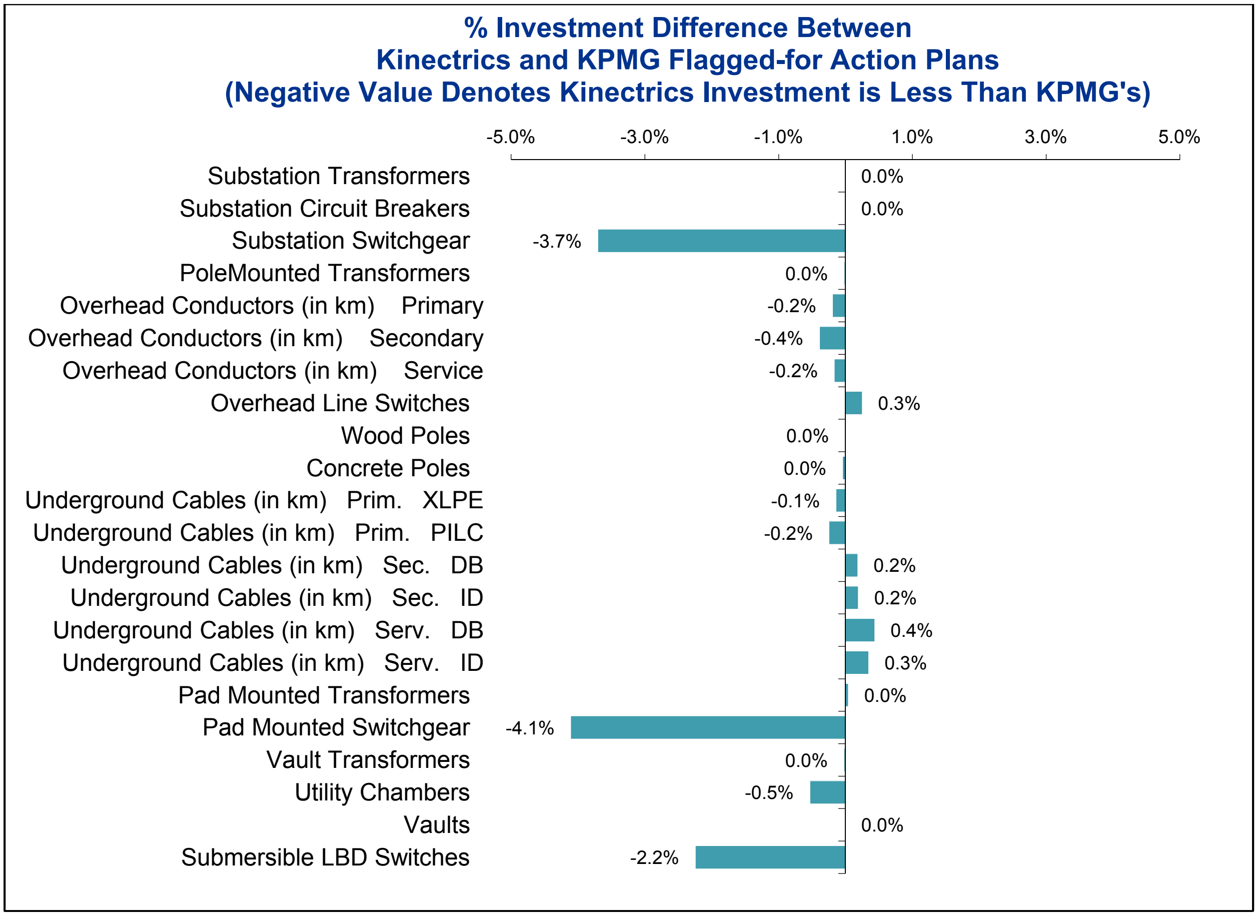


As evidenced by Figure 5 , the average effective age distributions for the different asset classes are virtually identical for both Kinectrics calculations and KPMG's calculations. Minor differences were observed for the proactively replaced assets (Substation Transformers, Substation Circuit Breakers and Substation Switchgear) but as the subsequent Flagged-for-Action analysis shows, these minor differences did not result in material differences in the Flagged-for-Action plans for these asset classes.

5.2.3 Flagged-for-Action Comparisons

Based on KPMG's calculated effective age distribution for each asset class, the Flagged-for-Action plans for the next twenty years were calculated based on whether the asset was deemed to be proactively replaced or reactively replaced. A detailed summary of the units Flagged-for-Action are shown in Appendix 1. The differences in the Flagged-for-Action plans are minor and are deemed to be immaterial. A summary of the percentage differences is shown in Figure 6, below.

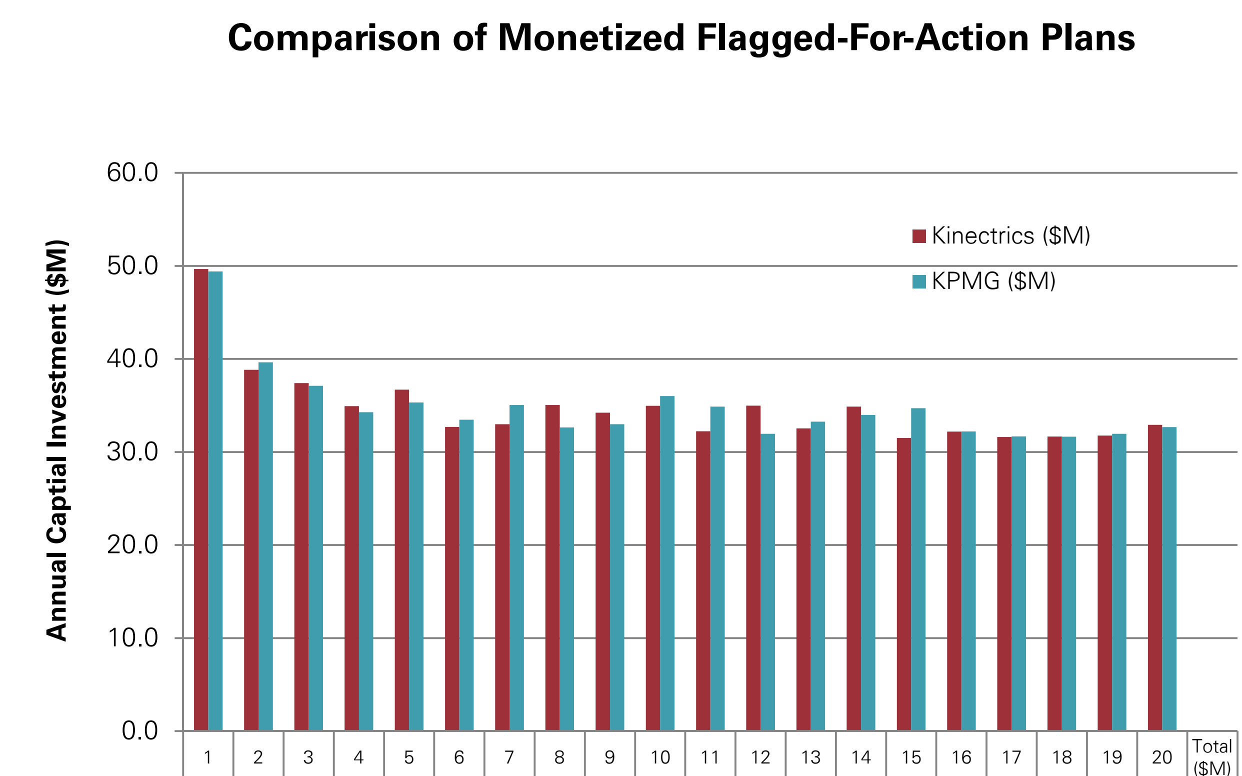
Figure 6: Percentage Difference in Flagged-for-Action Plans between Kinectrics and KPMG



The most significant percentage differences are in the Substation Switchgear, the Pad Mounted Switchgear and the Submersible LBD Switches asset classes. These asset classes have a small number of units in their population (less than 100 in each instance) and any small discrepancies in numeric values result in larger percentage differences when compared to other asset classes. The numerical differences can be found in Appendix 1. The impact of these differences to the Flagged-for-Action plan at the distribution network level over twenty years is immaterial.

Flagged-for-Action unit plans were monetized using standard unit costs in order to effectively allow comparison of the business impact of the identified differences. The standard unit costs used were provided by Horizon for each asset class. The resultant estimated investment over twenty years for the respective plans is shown in Figure 7 below.

Figure 7: Comparison of Monetized Flagged-for-Action Plans



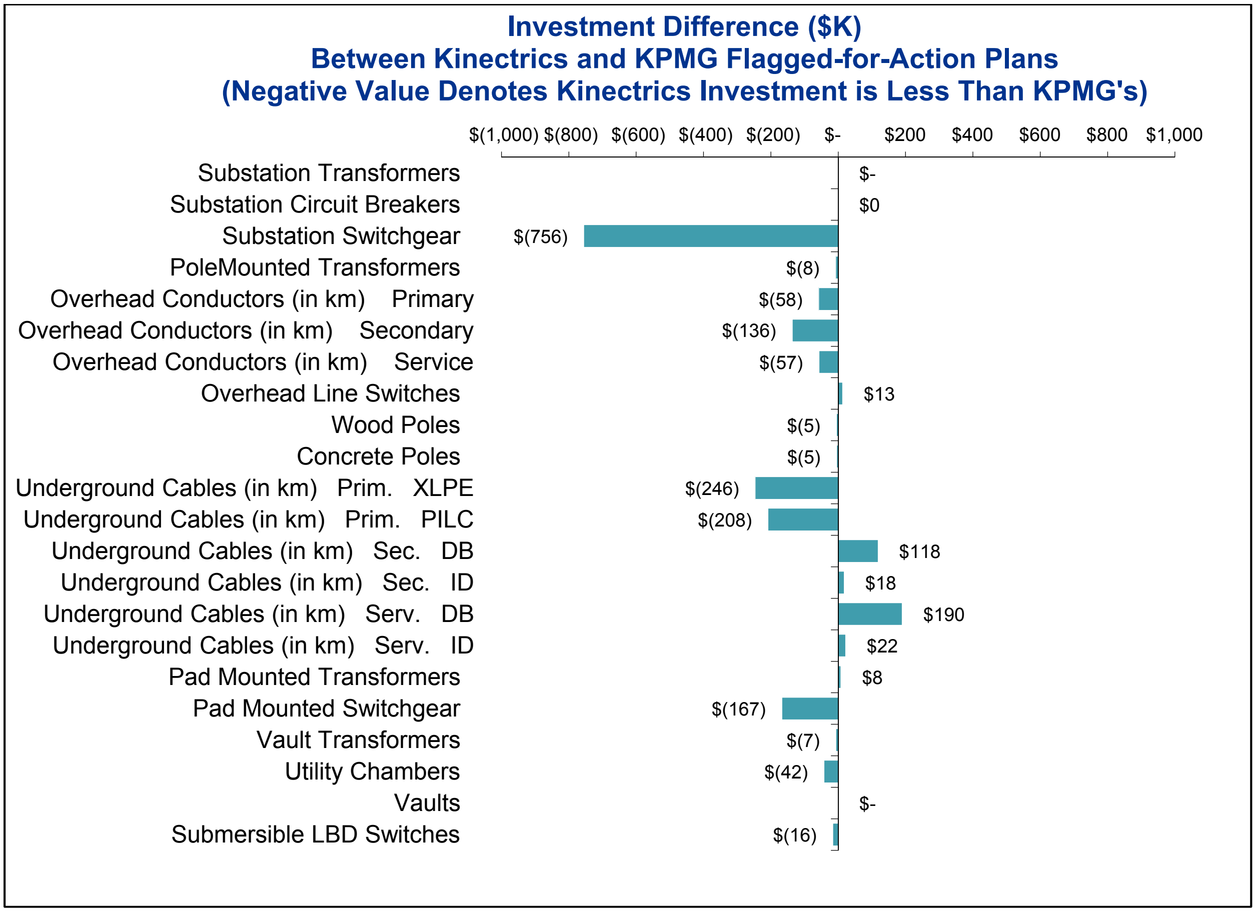
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
KPMG ($M)	49.4	39.6	37.1	34.3	35.3	33.5	35.0	32.6	33.0	36.0	34.9	32.0	33.3	34.0	34.7	32.2	31.7	31.6	31.9	32.7	694.8

Years into the Future

This monetized plan is meant to serve as a normalized comparison in dollar terms between the two respective Flagged-for-Action plans and it is not meant to be used as the definitive guide for Horizon's future capital investments. The two plans returned very similar total investment values over the twenty year span supporting the reasonableness of the calculations presented in the Kinectrics report. The total investment differs by only $1.1 million over twenty years or 0.02% for the period. The estimated monetary differences for each asset class are summarized in Figure 8, below.

When comparing Kinectrics and KPMG's results for the first five years of the monetized investment plan, the total investment portfolio difference found during this time period was $1.8 million or 0.09% of the five year plan. This investment difference was found to be primarily caused by the Substation Switchgear asset class. Due to the relatively low number of Substation Switchgear assets involved, the different values returned by the respective lookup methods employed by Kinectrics and KPMG resulted in slight variations in the timing of the Flagged-for-Action profile (See Appendix 1 for details). This variation was deemed to be insignificant to the overall five year Flagged-for-Action plan.

Figure 8: Comparison of Estimated Value of Flagged-for-Action Plans between Kinectrics and KPMG



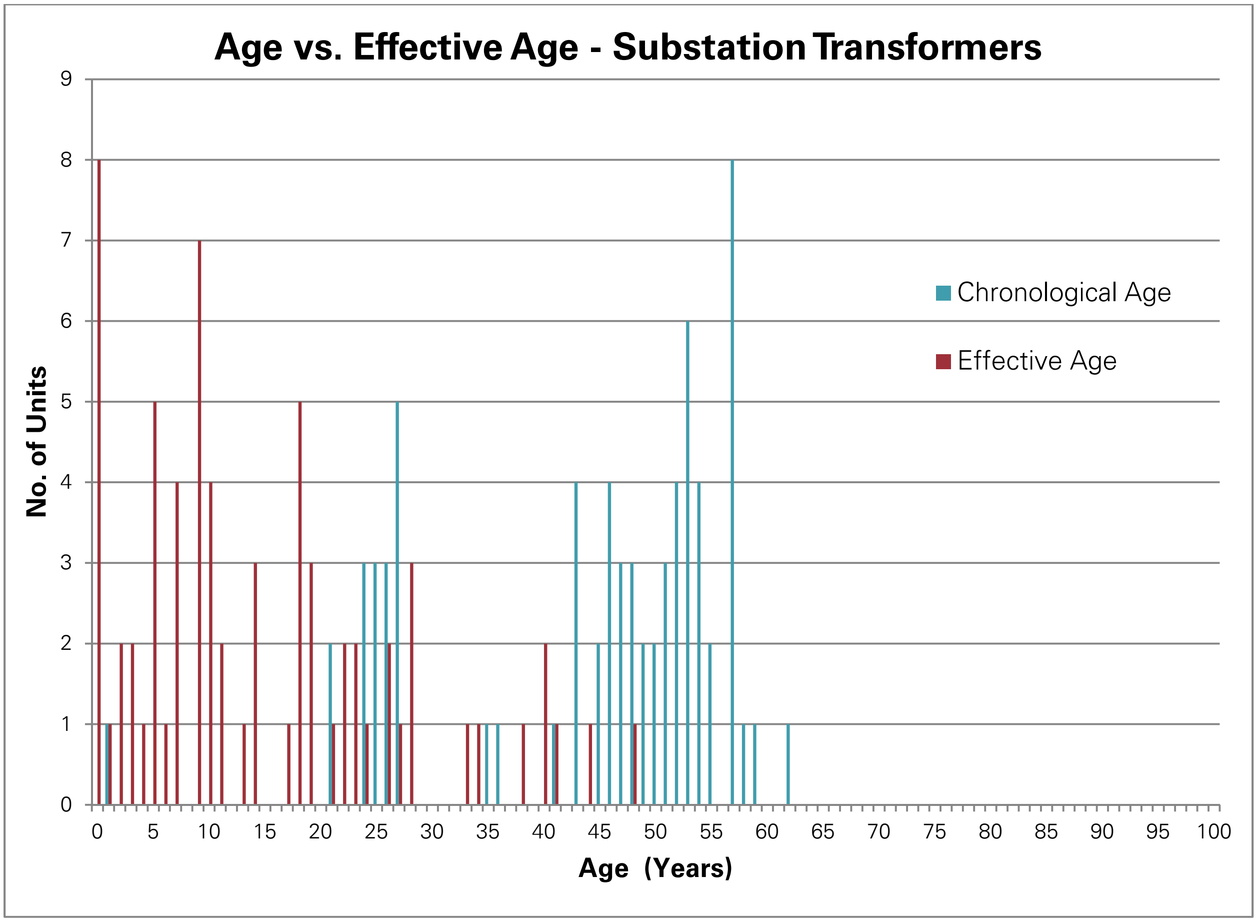
The results of the analysis show that Kinectrics' resulting end calculations can be replicated independently within a very small margin of error. It is KPMG's opinion that Kinectrics has accurately applied their published methodology and formulas contained in their report against the Horizon supplied asset data set.

5.3 Tests for Reasonableness

5.3.1 Comparison of Effective Age against Chronological Age

In order to test whether the health indices and the associated effective ages of assets were reasonable, the calculated effective age was compared to the chronological age in terms of age distribution and overall average age for each of the asset classes. The age distribution comparison test was meant to reveal whether the incorporation of the asset condition parameters played a major role in altering the chronological age in a material way. Figure 9 below is an example of the comparison conducted for each asset class.

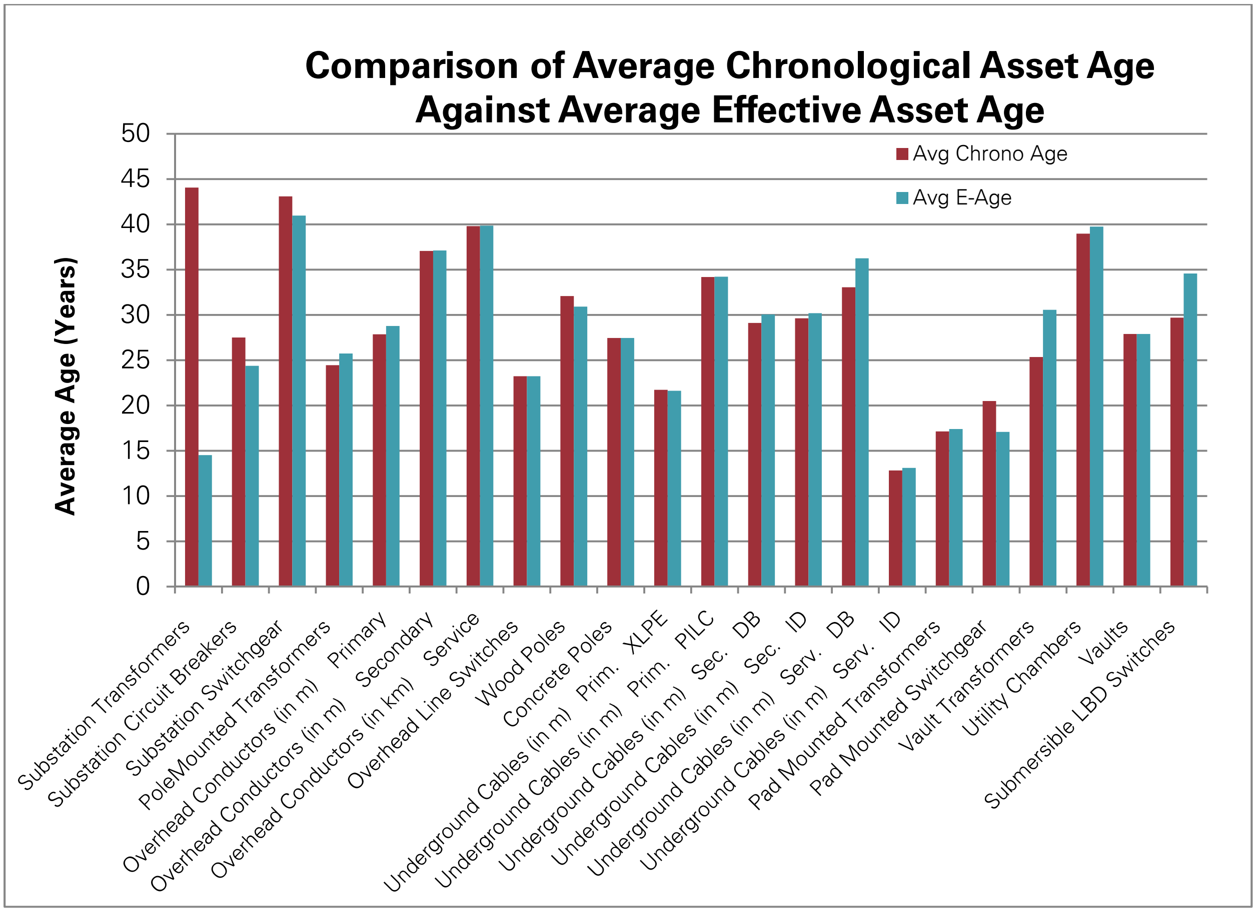
Figure 9: Example of Chronological Age versus Effective Age Comparison



The conversion of chronological age to effective age as a result of having asset condition parameters applied did shift the age distribution significantly for some asset classes. The differences between the average effective ages and the average chronological ages can be seen in Figure 10 below. The most significant shift is in the Substation Transformer asset class as the average effective age is significantly below the average chronological age. This phenomenon, as explained by Horizon representatives is the result of having significant maintenance and testing programs in place for this relatively old asset class to ensure their performance and reliability as these assets are key core components of the distribution system.

This test revealed that the use of effective ages to calculate the Flagged-for-Action plans would generate different end results than plans generated from chronological ages. However, the Flagged-for-Action differences in all the asset classes with the exception of the Substation Transformers would be reasonably close between the two different age profiles. For the Substation Transformers, the Flagged-for-Action plan using the assets' effective ages would significantly understate the number of units to be Flagged-for-Action when compared with a plan generated by the use of chronological age alone. Using effective ages to determine the Flagged-for-Action plan was deemed to be more reflective of actual asset conditions than using just chronological age.

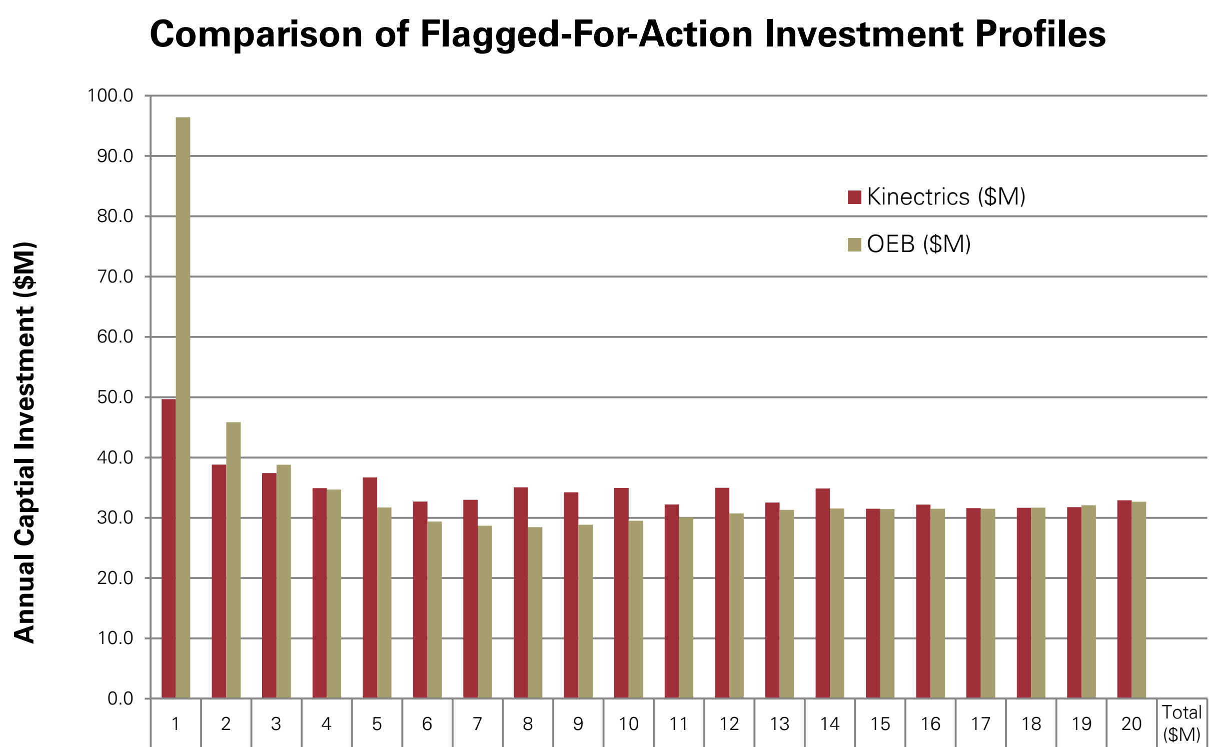
Figure 10: Comparison of Average Effective Ages against Average Chronological Ages



5.3.2 Comparison of Kinectrics' Flagged-for-Action Plan against Accepted Asset Life Standards

The final test to determine reasonability of the Kinectrics Flagged-for-Action plan was to compare the total plan against published and accepted industry standards for asset life expectancies. The standard life expectancies chosen for comparison were those published in the Asset Depreciation Study for the Ontario Energy Board (see Appendix 2). The published Typical Useful Life (TUL) and the Maximum Useful Life (MUL) were used to estimate the failure curve (f_t) and the cumulative probability of failure (P_f) for use in projecting asset replacements. Based on interpretation of the OEB report, the TUL was assigned 20% P_f, and the MUL was assigned 85% P_f. Failure curves were subsequently developed using the published TUL and MUL figures; the only exception was for the Submersible LBD Switches for which figures were not available in the OEB report. For this asset class, the UG Vault switch values for TUL and MUL were used as a proxy. Flagged-for-Action plans for each asset class were then calculated using the chronological age as the OEB useful lives data was developed for use with chronological asset age. The comparison of the normalized monetary results for the two different Flagged-for-Action plans is shown in Figure 11 below.

Figure 11: Comparison of Kinectrics Flagged-for-Action Plan versus Plan Generated from OEB Data



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total ($M)
Kinectrics ($M)	49.7	38.8	37.4	34.9	36.7	32.7	33.0	35.1	34.2	35.0	32.2	35.0	32.5	34.9	31.5	32.2	31.6	31.7	31.8	32.9	693.7
OEB ($M)	96.4	45.9	38.8	34.7	31.7	29.4	28.7	28.4	28.9	29.5	30.1	30.7	31.3	31.6	31.4	31.5	31.5	31.7	32.1	32.7	706.9

The total estimated investment for the two different plans over twenty years is within 2% of each other. The results calculated from the OEB life expectancies are heavily front-end loaded suggesting that model assesses Horizon’s asset base as being closer to end of life than Kinectrics effective age model. This comparison substantiates the life curves used by Kinectrics in their models are reasonably close to industry accepted useful life data. The Kinectrics’ life curves have longer average expected life-spans for some of the asset classes leading to fewer asset investments identified for the immediate short term. When compared to the OEB results, the Kinectrics Flagged-for-Action plan is not overstated and is reasonably within the industry accepted asset replacement or refurbishment practices for distribution utilities in Ontario.

6 Conclusions

Based on an independent assurance review of the methodology and analytics used in the Kinectrics report, it is KPMG's opinion that the approach used to arrive at the presented results is in line with industry practice and generally accepted methodologies. KPMG is of the opinion that the presented methodology has been appropriately and consistently applied against the Horizon supplied asset data in order to derive the final Flagged-for-Action plans for each of the asset classes. The interim and final results as presented in the Kinectrics report have been independently validated by KPMG to an acceptable margin of error for the intended purpose of projecting asset replacements or refurbishments over a twenty year period. When compared with accepted industry standards and practices for useful asset life, Kinectrics Flagged-for-Action plans appear to be reasonable and in line with industry expectations.

Appendix 1 Comparison of Twenty Year Flagged-for-Action Plans

Assets Class	Source	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Total
Substation Transformers	Kinectrics	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	2	5
Substation Transformers	KPMG	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	1	2	5
Substation Circuit Breakers	Kinectrics	16	0	10	0	11	0	9	0	17	0	7	0	0	0	0	9	1	0	0	9	89
Substation Circuit Breakers	KPMG	16	0	10	0	11	0	9	11	6	7	0	0	0	0	0	9	1	0	0	9	89
Substation Switchgear	Kinectrics	1	0	1	1	4	0	0	4	2	4	0	4	1	4	0	0	0	0	0	0	26
Substation Switchgear	KPMG	0	1	1	0	2	1	3	0	1	5	4	0	2	3	4	0	0	0	0	0	27
PoleMounted Transformers	Kinectrics	593	277	232	218	215	217	220	223	226	228	229	229	230	230	231	234	238	244	252	262	5028
PoleMounted Transformers	KPMG	594	277	232	218	215	217	220	223	226	228	229	229	230	230	232	234	238	244	252	262	5029
Overhead Conductors (in km) Primary	Kinectrics	53	45	40	37	34	32	31	30	29	30	30	31	32	32	32	33	33	33	33	34	684
Overhead Conductors (in km) Primary	KPMG	53	46	41	37	34	32	31	30	29	30	30	31	32	32	33	33	33	33	33	34	685
Overhead Conductors (in km) Secondary	Kinectrics	86	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	843
Overhead Conductors (in km) Secondary	KPMG	87	63	52	44	40	38	38	38	39	39	39	39	39	39	38	37	36	34	33	32	846
Overhead Conductors (in km) Service	Kinectrics	97	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	32	30	28	27	809
Overhead Conductors (in km) Service	KPMG	99	69	54	44	39	36	35	36	36	36	36	36	36	35	34	33	31	30	28	27	810
Overhead Line Switches	Kinectrics	31	26	23	22	20	20	19	18	19	18	18	18	17	17	17	17	16	17	17	17	387
Overhead Line Switches	KPMG	31	26	23	22	21	20	19	19	18	18	18	17	17	17	17	17	17	17	17	17	386
Wood Poles	Kinectrics	1509	1103	1011	967	935	905	876	845	814	782	752	724	699	678	662	648	637	627	619	611	16404
Wood Poles	KPMG	1509	1103	1011	968	935	906	876	845	814	782	752	724	699	678	661	648	637	627	619	611	16405
Concrete Poles	Kinectrics	97	98	100	101	103	104	105	107	108	109	110	111	112	114	115	118	119	121	123	126	2201
Concrete Poles	KPMG	97	98	100	101	103	104	105	106	108	109	110	111	112	114	116	117	119	121	124	126	2202
Underground Cables (in km) Prim. XLPE	Kinectrics	126	103	96	91	88	85	83	80	78	76	74	72	71	70	69	68	67	66	66	66	1595
Underground Cables (in km) Prim. XLPE	KPMG	127	103	95	91	88	85	83	80	78	76	74	73	71	70	69	68	67	67	66	66	1597
Underground Cables (in km) Prim. PILC	Kinectrics	11	11	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	339
Underground Cables (in km) Prim. PILC	KPMG	12	12	12	12	12	13	14	14	15	16	17	18	19	20	20	21	22	23	24	25	340
Underground Cables (in km) Sec. DB	Kinectrics	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	519
Underground Cables (in km) Sec. DB	KPMG	28	28	28	27	27	27	27	27	26	26	26	26	25	25	25	25	24	24	24	24	518
Underground Cables (in km) Sec. ID	Kinectrics	21	21	21	20	20	19	19	19	18	18	18	18	17	17	17	17	17	16	16	16	365
Underground Cables (in km) Sec. ID	KPMG	21	21	20	20	20	19	19	19	18	18	18	18	17	17	17	17	16	16	16	16	364
Underground Cables (in km) Serv. DB	Kinectrics	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	352
Underground Cables (in km) Serv. DB	KPMG	20	20	20	19	19	19	19	18	18	18	18	17	17	17	16	16	16	15	15	15	350
Underground Cables (in km) Serv. ID	Kinectrics	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14	14	14	15	15	15	257
Underground Cables (in km) Serv. ID	KPMG	10	11	11	11	11	12	12	12	12	13	13	13	13	14	14	14	14	15	15	15	256
Pad Mounted Transformers	Kinectrics	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Transformers	KPMG	17	17	20	23	27	31	36	41	47	53	59	65	70	75	79	83	87	92	98	105	1125
Pad Mounted Switchgear	Kinectrics	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	5	70
Pad Mounted Switchgear	KPMG	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	73
Vault Transformers	Kinectrics	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	162	156	150	144	139	4250
Vault Transformers	KPMG	309	294	282	270	260	250	240	230	221	212	203	194	186	178	170	163	156	150	144	139	4251
Utility Chambers	Kinectrics	12	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	23	24	25	26	373
Utility Chambers	KPMG	13	13	13	14	15	15	16	17	17	18	19	20	20	21	22	23	24	24	25	26	375
Vaults	Kinectrics	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Vaults	KPMG	6	7	7	7	8	8	9	10	10	11	12	12	13	14	15	16	17	18	19	20	239
Submersible LBD Switches	Kinectrics	14	8	7	6	5	5	5	4	4	4	3	3	3	3	2	2	2	2	2	3	87
Submersible LBD Switches	KPMG	14	8	7	6	5	5	5	4	4	4	4	3	3	3	3	3	2	2	2	2	89

Appendix 2 Summary of OEB's Asset Useful Lives

F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS Category | Component | Type			USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
			Battery bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
	18	Station Switch			30	50	60	M	L	M	M	M	L

* OH = Overhead Lines System TS & MS = Transformer and Municipal Stations
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS Category | Component | Type		USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
TS & MS	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
TS & MS	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
TS & MS	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
TS & MS	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
UG	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
UG	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
UG	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
UG	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
UG	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
UG	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
UG	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
UG	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
UG	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
			Protector	20	35	40						
UG	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
UG	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
UG	36	UG Foundations		35	55	70	M	NI	M	L	L	M
UG	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
			Roof	20	30	45						
UG	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
UG	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
UG	40	Ducts		30	50	85	H	NI	M	NI	NI	L
UG	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
UG	42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H

* TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

References

Kinectrics Inc. (2013). *Horizon Utilities 2013 Asset Condition Assessment.* Toronto: Kinectrics Inc.

Kinectrics Inc. Report No: K-418033-RA-001-R000. (2010). *Asset Depreciation Study for the Ontario Energy Board.* Toronto: Kinectrics Inc.

Author Biography

Julius Pataky, P.Eng. MBA

Julius Pataky is a KPMG Partner with 35 years progressive industry and consulting experience in the energy industry, with demonstrated leadership skills in asset management, building effective teams, leading transformation and bringing innovation to the business. Julius joined KPMG after having led innovative asset management solutions at BC Transmission and BC Hydro. In his roles as VP, Asset Investment, he brought the PAS 55 framework into organization's operating model, led the development of innovative asset analytic and planning solutions and gained regulatory approval for increased capital investment. He not only had accountability for developing the Capital Plans for transmission and distribution but also developing the regulatory justification for these capital investments. During this period, investments in the grid for the utility had grown from under $200M/yr to $1.3B/yr. He acted as company lead in communication of the need for increase in grid investment with stakeholders and the public. He also led numerous consultation efforts to gain acceptance of contentious projects with municipal leaders and landowners.

David Cheng, P.Eng.

David Cheng is a Senior Manager in KPMG LLP's Advisory Services Practice and is a member of the firm's Asset Management practice. Over his career, David has successfully transformed numerous businesses through his knowledge of asset management, operations management, business process improvement, information management and project and program management. He has led a diverse portfolio of projects as a consultant for private and public sector organizations plus he has years of executive and managerial experience leading teams in the utilities, aerospace, high-technology, healthcare and consumer products industries. As a former Manager of Asset Data and Information at BC Hydro and BC Transmission Corporation (BCTC), David was responsible for the development of asset analytic algorithms used to support capital investment justifications contained within the rate application submissions to BC Utilities Commission (BCUC). The asset analytics deployed probabilistic asset health based analysis to determine projected asset replacement requirements based on asset condition and asset demographics.

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BOMA-4-Attch_4 – Questionnaire

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Review of Horizon Utilities Asset Condition Assessment Review

1.	Please verify Equations 1 & 2 shown on page 7 of the Horizon Utilities 2012 Asset Condition Assessment October 31, 2013 Report (the Report) were used to calculate the Health Indices in the Report.
2.	Please confirm the Probability of Failure vs. Health Index curve shown on page 14 of the Report is the integral of the normally distributed Probability Density Curve of Stress shown on page 13 of the Report.
3.	At Health Index rating of 15%, what is the cumulative probability of failure used in the graph on page 13 of the Report?
4.	Please explain the relationship between the following two statements found on pages 15 and 16 of the Report (a) *"A unit becomes a candidate for replacement when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1"* (b) *"For proactively replaced assets, the Condition-Based Flagged-For-Action Plan shows the optimal time of replacement, which is determined by the time when Health Index based probability of failure exceeds 80%"*

5.	How is the "Avg Annual Replacement Cost" in Table IV-2 calculated? What components of costs are included?
6.	How were the life curves determined for each asset class? Please provide specific examples for Substation Transformers and Substation Circuit Breakers.
7.	Please provide Year 1 Flagged-For-Action outputs for Pole Mounted Transformers. Please provide unit distributions of assets against years and expected replacement quantities against years.
8.	Please explain variance between Figure 14-3 and Figure 14-4.
9.	Please provide Year 2015 Flagged-For-Action outputs for Vaults. Please provide unit distributions of assets against years and expected replacement quantities against years.

BOMA-5

Reference:

DSP Appendix E. Renewable Energy/Regional Plans

(a) Please provide a copy of the Board letter dated March 28, 2013

(b) P3:

(i) What is the average time between an application to connect counsel and a successful connection.

(ii) When does Horizon expect the remainder of the 54 applications to the connected

(c) P5: Why does Horizon not intend to connect any solar facilities as owned by Solar Sunbelt General Partnership ("SSGP") during the IRM. Does SSGP not operate within the Horizon franchise. Please discuss fully.

(d) P6: Please explain the rationale for the IEEE 1547 rule that generation on a feeder must not exceed 33% of the minimum feeder load. Please provide a copy of the IEEE 1547 document. How many of Horizon's feeders are length are in the same position as the one cited in the evidence. What measures has Horizon taken or is it taking to ensure that these requirements do not stymie the growth of distributed generation in its franchise. Are there any other technical conditions/constraints that have, or may limit the growth of distributed generation in its franchise..

(e) P12: Given the small size of the typical rooftop solar project, why does Hydro One Nebo Transformer station lack capacity to handle it. Hydro One is currently expanding the capacity of Nebo. Will it be able to handle the generation. Please explain the nature of the constraint at Nebo. Please explain fully, especially the short circuit resilience issue.

Response:

a) Horizon Utilities has provided a copy of the Board letter dated March 28, 2013 as attachment BOMA-5_Attch_Chapter_5_covltr_CDSP_Filing_Reqs_20130328.

b) (i) Horizon Utilities does not recognize the term “application to connect counsel”. Horizon Utilities does track the following milestones:

- Connection Impact Assessment (“CIA”) agreement date;
- CIA completion date; and
- Connection date.

For the 31 FIT projects connected as of July 7, 2014 the average time to connect was 16 months from the date of the CIA Agreement.

b) ii) Horizon Utilities is not aware of when the respective customers plan to connect their distributed generation.

c) Horizon Utilities does intend to connect solar facilities as owned by Solar Sunbelt General Partnership (“SSGP”). Horizon Utilities identifies that there was an incorrect statement on page 5 of Appendix E of the DSP that indicated to the contrary. SSGP has seven solar Photovoltaic (PV) systems with Feed-In-Tariff (“FIT”) contracts that are located in Horizon Utilities’ service territory. All seven systems are connected to Horizon Utilities’ distribution network. Should SSGP be awarded additional FIT contracts for systems located in Horizon Utilities’ territory during rate plan period, Horizon Utilities would undertake to connect those systems in a manner consistent with the applicable FIT contract and any other prevailing regulation.

d) The IEEE 1547-2002 standard which Horizon Utilities follows is based on evidence from studies and supported by Hydro One Technical Interconnection Requirements (“TIR”). The rationale the IEEE 1547-2002 standard limiting total generation of a feeder to below 33% of the minimum feeder load is to prevent ‘islanding’ where the distributed generator (“DG”) continues to power a location even though service from the electric utility is no longer present.

Horizon Utilities is unable to provide a copy of the IEEE 1547 as this would violate copyright laws as identified within the body of the IEEE 1547 standard.

Horizon Utilities has not calculated the current minimum load for each feeder within the distribution system. The minimum load is dependent upon the size of DG being connected and the existing DG on the feeder. The calculation of the minimum load is performed on a feeder upon receipt of a DG application for the feeder as part of Horizon Utilities’ technical assessment of the application. Horizon Utilities cannot quantify the number of feeders affected by this requirement.

The minimum loading requirement referred to in this question is a function of the amount of customer load on each feeder. Horizon Utilities does not have the ability to increase the minimum loading of feeders. It cannot remove this constraint on feeders affected by this requirement.

However, the conversion of feeders from 4kV to 13.8kV or 27.6kV, through the 4kV and 8kV Renewal Program, will reduce the impact of this requirement. Horizon Utilities provides Table 1 below to illustrate the minimum feeder loading required to allow the connection of 250kW of DG to a feeder at each voltage level. As illustrated in the table, the minimum feeder load, as a percentage of the maximum feeder load, required to allow the connection at 13.8kV and 27.6kV is 6% and 3% respectively, versus the 35% of maximum feeder load required on the 4kV distribution system.

Table 1: Feeder Loading Required at 250kW of DG

Scenario: 250kW of DG coneected for feeder				
Distirbution System	**DG load (A)**	**Min Feeder Load (A)**	**Max Feeder Load (A)**	**% of Max Feeder Load**
4 kV	35	104	300	35%
8 kV	17	52	300	17%
13.8 kV	10	31	500	6%
27.6 kV	5	16	500	3%

At this time Horizon Utilities has not encountered any other limitations that would affect the growth of distributed generation under Fit or microFit.

e) Horizon Utilities does not know the details that existed for the constraint other than short circuit and thermal limitations at Nebo TS. This question should be referred to Hydro One for clarification as Nebo TS is a Hydro One asset. BOMA is correct, Nebo capacity has been expanded. On June 27, 2014 Horizon Utilities received 1MW of allocation for distributed generation at Nebo TS for the B Bus.

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BOMA-5_Attch_Chapter_5_covltr_CDSP_Filing_Reqs_20130328

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Ontario

VIA E-MAIL AND WEB POSTING

March 28, 2013

To: All Participants in Renewed Regulatory Framework for Electricity Consultations EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004
All Licensed Electricity Distributors
All Other Interested Parties

Re: Issuance of *Filing Requirements for Electricity Transmission and Distribution Applications*; Chapter 5 – Consolidated Distribution System Plan Filing Requirements

Board File Number EB-2010-0377

Today the Board issued Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications*, entitled 'Consolidated Distribution System Plan Filing Requirements'. Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', set out in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

Chapter 5 was prepared with advice and input from a Working Group of eleven stakeholders. The Board wishes to express its appreciation for their efforts and contributions.

Application and time of filing

Chapter 5 applies to licenced, rate regulated electricity distribution utilities in Ontario filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a

Chapter 5 filing in relation to leave to construct, Incremental Capital Module or Z-factor applications.

Transitioning to Chapter 5

Under the renewed regulatory framework for electricity, a distributor's investments to accommodate and connect renewable energy generation and to develop and implement a smart grid are integral to its overall capital expenditure plan. Consequently, for future distributor filings as indicated above, the Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* will no longer apply. However, distributors who have yet to file under Chapter 5 will, where applicable, continue to be able to record renewable energy generation costs and smart grid demonstration costs, in the deferral accounts that have been established for that purpose.

Within the next few months, amendments to Chapter 2 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications* for cost of service rate applications will be issued, including those changes required to complement Chapter 5.

At the same time, the Board will re-issue the Report of the Board - *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09,* revised to reflect the Board's policy direction on an integrated approach to distribution network planning.

Future outreach on implementation

The Board intends to schedule meetings over the spring/summer period to address any questions distributors may have on Chapter 5 or on any of the planning related instruments issued by the Board to implement the renewed regulatory framework for electricity.

In the interim, questions about Chapter 5 or any of the Board's *Filing Requirements* can be directed to:

- the Market Operations Hotline at 416-440-7604; or
- by e-mail to market.operations@ontarioenergyboard.ca.

DATED at Toronto, March 28, 2013

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

BOMA-6

Reference:

Regional Plans

(a) P23: Please provide more detail on the Brant sub-region IRRP. Please confirm that in both the Brant and the Burlington-Nanticoke plans all CDM options, including distributed generation are being considered. Please provide the draft plans.

(b) P-: Will the 4kV/8kV conversion plan per se allow additional generation to be added the higher voltage feeders relative to the original 4/8kV. Please explain fully.

Response:

a) Horizon Utilities is not officially part of the Brant sub-region IRRP, as provided in Exhibit 2, Table 6, Appendix 2-4, Appendix E - REG Investment Plan, page 23. Horizon Utilities altered its involvement in the Brant sub-region IRRP to a review role only. The reason for this was that none of the facilities involved in that study within Horizon Utilities' service territory needed investment. Horizon Utilities reviewed a draft copy of the Terms of Reference which was finalized and posted on April 17, 2014 on the Hydro One website. Horizon Utilities has downloaded all the publicly available documents on the Brant sub-region IRRP from the Hydro One website and has provided the following attachments:

- BOMA-6_Attch 1_BARP Feb 06 2014
- BOMA-6_Attch 2_RP Planning Activities
- BOMA-6_Attch 3_Explanatory Note

Horizon Utilities has no other documents to provide.

- Horizon Utilities cannot confirm that in the Brant and Burlington-Nanticoke plans that all CDM options, including distributed generation are being considered. Horizon Utilities' understanding is that an IRRP can result in a CDM or distributed generation solution to resolve a system constraint. Horizon Utilities provides the final version of the Needs Screening for the Burlington-Nanticoke region as attachment "BOMA-6_Attch 4_Needs Screening Report".

b) Horizon Utilities cannot provide an absolute assessment on whether the 4kV and 8kV Renewal Program will allow additional distributed generation ("DG") to be added relative to the original 4kV and 8kV distribution voltage due to the number of variables and assumptions required. The total generation allowed is a function of the thermal and short circuit limitations of the feeder and the minimum feeder loading. The thermal and short circuit limitations vary per feeder and are not necessarily a function of the voltage level. The conversion of a feeder to a higher voltage level will reduce the impact of the IEEE 1547-2002 minimum voltage requirement and allow the connection of additional DG as described in Horizon Utilities' response to Interrogatory BOMA-5 (d).

BOMA-6_Attch 1_BARP Feb 06 2014

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February 06, 2014

Mr. Bing Young
Director, Transmission System Development
Hydro One Networks
483 Bay Street
Toronto, Ontario M5G 2P5

Brant Area Regional Planning – Initiating the Implementation of the Near-Term Wire(s) Solution

Dear Bing:

The purpose of this letter is to request Hydro One Networks to initiate the implementation of a wire(s) solution - providing additional reactive support - to address the near-term supply need in the Brant Area.

The Brant Regional Planning Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One Transmission and Distribution, Brantford Power and Brant County Power has been conducting an Integrated Regional Resource Planning (IRRP) process for the Brant sub-region within the Burlington to Nanticoke Region. The IRRP process develops and analyzes forecast for demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC) and develops integrated solutions to address any needs that are identified.

While the IRRP for the Brant study area is not yet complete, the study has identified an urgent need to increase the load meeting capability (LMC) of the B12/13 circuits supplying Brant TS and Powerline MTS. The LMC for this supply was determined to be 104 MW based on voltage criteria. The peak loading on these circuits was approximately 118 MW in summer 2013 and is forecasted to reach 126 MW by 2016. Studies show that the installation of capacitor bank(s) at Powerline MTS will provide adequate relief to allow the circuits to be operated to their thermal capability, which will be approximately 125 MW. The load transfer among the Brant area stations will also allow effective use of the existing installed capacity. The Working Group believes that, along with the level of conservation expected to be achieved in this area, additional reactive support provides the most economic and effective solution for addressing this near-term need in this area.

Under the Ontario Energy Board's (OEB) recently endorsed regional planning process, in cases where an IRRP is still in progress but it has determined that a transmission and/or distribution wires solution is necessary to best address a near-term need, a "hand off" letter would be provided from the OPA to the lead transmitter, in this case Hydro One Networks, to initiate the implementation of a wire(s) solution. This is the case for the Brant Regional Planning Study.

The details associated with the near-term wire(s) solution will be determined by Hydro One Networks and relevant LDCs in the sub-region. The following information from the studies done and discussions had by the Working Group may be helpful to Hydro One Networks in the development of this project.

- The required date of this transmission reinforcement project is as soon as practical.
- The OPA studies considered a maximum of 30 MVar reactive compensation at Powerline MTS.
- The IESO has concern with excessive voltage change on switching a single 30 MVar capacitor bank at Powerline MTS.
- Hydro One and LDC(s) will develop optimum configuration of bank sizes and location, along with distribution transfer options.

We look forward to information, results and deliverables from this project as part of the Brant Working Group activities. We will continue to work with and support Hydro One and LDCs on the implementation of this work.

Regards,

R.F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC:
Brant Working Group members

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Mark Simpson
Steve Faulkner

Brant County Power
Michael Desroches
Glen Fuller

Hydro One Distribution
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Wajiha Shoaib
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Luisa Da Rocha (OPA)
Charlene de Boer (OPA)
Richard Bassindale (Horizon Utilities Corporation)

BOMA-6_Attch 2_RP Planning Activities

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The planning activities for the Burtlington to Nanticoke Brant Subregion were already in progress before the Ontario Energy Board's endorsement of the new and more structured regional planning process in Ontario, as proposed in the 2013 Planning Process Working Group (PPWG) Report. The new and structured regional planning process includes the following steps and the publication of these specific documents:

1. The 'needs screening', which is led by the lead transmitter and produces the Needs Screening Report;
2. The 'scoping assessment', which is led by the OPA and produces the Scoping Assessment Outcome Report;
3. 'Integrated regional resource planning, which is led by the OPA and produces the Integrated Regional Resource Plan (IRRP);
4. And 'regional infrastructure planning', which is led by the lead transmitter and produces the Regional Infrastructure Plan (RIP).

As planning work in the Burtlington to Nanticoke Brant Subregion was already underway before this process, the published documents differ from those required under the new process.The Terms of Reference is available, which includes screening and scoping information for this region. To view this document, follow the link to the OPA's website found here:

http://powerauthority.on.ca/sites/default/files/planning/Brant-Terms-of-Reference.pdf

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BOMA-6_Attch 3_Explanatory Note

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EXPLANATORY NOTE

These are the original Terms of Reference for the Brant integrated regional planning study, which is a sub-region of the Burlington to Nanticoke region. These Terms of Reference were developed by the regional planning working group in 2013. They detail the objectives, scope, key assumptions, study team, activities, accountabilities, and deliverables for the planning study, and reflect the context for regional planning at that time.

Since the development of these original Terms of Reference, there have been a number of key regulatory and policy changes that impact how regional planning is to be conducted in Ontario. The Ontario Energy Board (OEB) has endorsed a more structured and formalized regional planning process, which sets out the responsibilities of the working group, the timelines, and the documentation requirements for planning in Ontario's 21 electricity regions. Additionally, the Premier of Ontario has endorsed recommendations regarding stakeholder and community engagement in regional planning and the siting of large electricity infrastructure.

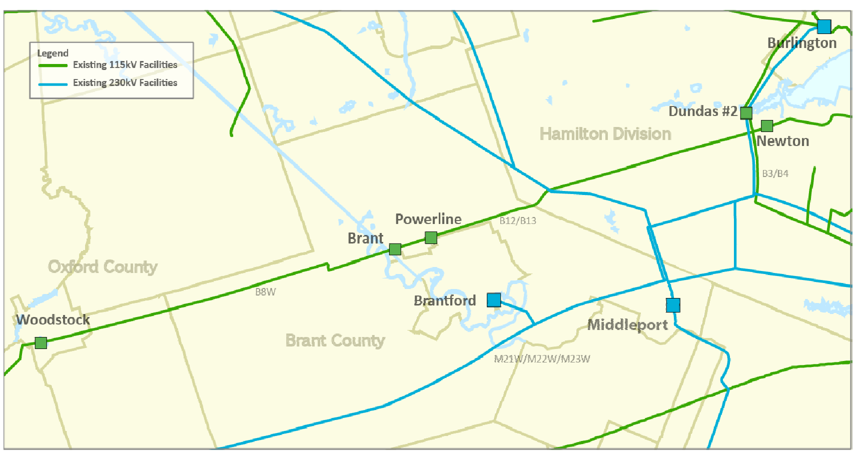
Included in the new framework for regional planning is the integrated regional resource planning process. The Brant regional planning study is being transitioned to align with this process, as well as with the planning and siting recommendations. The outcome of this process will be to complete and post online an Integrated Regional Resource Plan (IRRP), which will guide electricity planning in this region. During this transitional period, these original Terms of Reference are being made publicly available in order to better align with the new process and provide greater transparency to stakeholders. To access the most up-to-date schedules and other information related to this regional plan, please refer to the region's web page at: http://powerauthority.on.ca/power-planning/regional-planning/burlington-nanticoke/brant

Terms of Reference
Brant Area Integrated Regional Resource Planning Study

1. Introduction

The Brant Area encompasses the County of Brant and City of Brantford. The electricity supply to this area is provided by three Dual-Element Spot Network (DESN) stepdown stations - Brant TS, Powerline MTS and Brantford TS – as shown in Figure 1. Brant TS and Powerline MTS are connected to the double-circuit 115kV transmission line, B12/13, originating from Burlington TS. These stations are also backed up in emergencies by the 115 kV line B8W from Woodstock. The Brantford TS is supplied at 230 kV from the double-circuit transmission line M21/32W between Middleport TS (Hamilton) and Buchanan TS (London). The coincident peak demand of the three stations in summer 2012 was approximately 250 MW. Distribution service to customers in the area is provided by Brant County Power Inc., Brantford Power Inc. and Hydro One Distribution. Circuits B12/13 also supply two other DESN stations, Dundas #2 TS and Newton TS in the Hamilton area serving customers of Horizon Utilities Corporation and Hydro One Distribution.

Figure 1 – Map of the Brant Area and vicinity



Planning of supply and infrastructural expansions to address regional electricity needs has now been formalized and will follow a process developed by the Planning Process Working Group and endorsed by the Ontario Energy Board. At this time, amendments to the Transmission System Code (TSC) and Distribution System Distribution to facilities the implementation of this process are being proposed by the OEB and will be enacted once comments have been received and considered. A figure showing the high-level flowchart of this process is shown in the Appendix. [1]

Consistent with this planning process, Hydro One has carried-out a "need screening" study for the Brant area. They concluded that there is a need to conduct a regional planning for this area in order to maintain a reliable electricity supply to its customers. Note that the Brant Area is a sub-area within the Burlington/Nanticoke region. Due to the geographic dispersion of the pockets in a big region, and the diverse nature and timing of the anticipated needs, it makes sense to study Brant area needs and develop solutions through a separate sub-study. Nonetheless, before committing to the preferred solution(s), their impacts will be studied from a region-wide perspective to ensure that they represent an overall best solution for the region as a whole.

The OPA has assessed potential solutions that might address the needs and identified that conservation and demand management (CDM), local generation, and transmission and distribution (T&D) solutions are all viable for address the area's electricity supply needs. As such, the IRRP process should be employed for this planning exercise. .

This Terms of Reference is developed by the Brant Area Working Group. It establishes the objectives, scope, roles and responsibilities, activities and timelines for the Brant Area IRRP Study.

2. Objectives

- To assess the adequacy of electricity supply to customers in the Brant area over a 20-year timeframe, focusing on near-term requirements and solutions (within the next 5 years), mid-term optionality and solutions (5-10 years out) and long-term direction and solutions (10-20 years in the future).
- To develop integrated demand and supply options to address the identified needs.
- To develop an implementation plan for the recommended options.

3. Scope

This IRRP Study will develop a comprehensive near, medium and long term regional plan to meet supply needs and reliability of Brant area at various time horizons. The study is a joint initiative involving the OPA, Hydro One Transmission, affected LDCs (Brantford Power Inc., Brant County Power Inc., and Hydro One Distribution) and the IESO, and will incorporate input from other entities as required. The study will integrate demand growth projections, bulk system needs, relevant community plans, local generation uptake, Conservation and Demand Management (CDM) as well as local constraints to ensure that system adequacy needs arising from assessment of projected demand growth are appropriately captured.

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[1] More information is available via this link to the OEB website: http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework.

3.1 Study Area

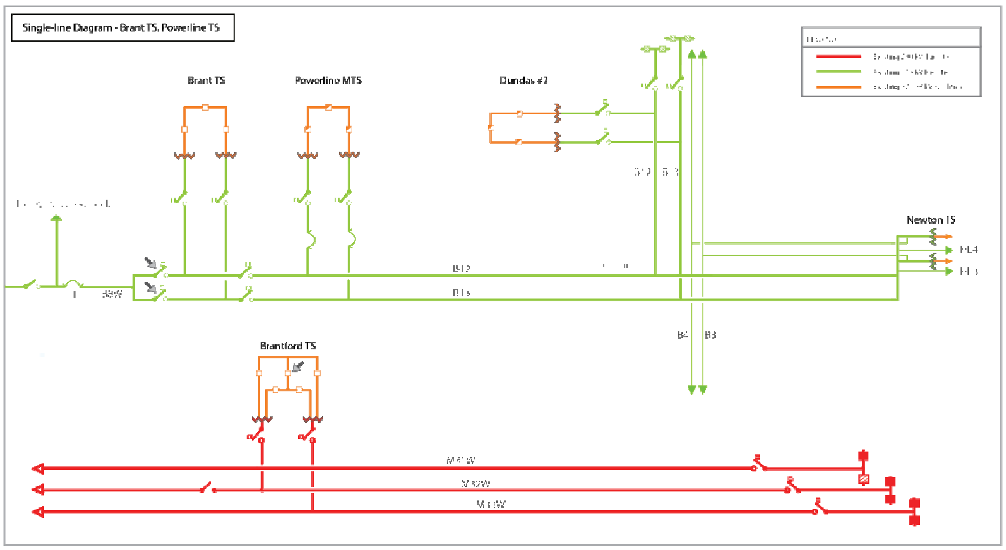
For the purposes of this study, the term “Brant Area” is used more precisely to define the area supplied by the following transformer stations from the 115kV transmission facilities B8W, B12/13 and the nearby Brantford TS:

- Brant TS, Powerline MTS, Newton TS, Dundas #2 TS[2] and Brantford TS.

A single line diagram of Brant area transmission system is shown in Figure 2.

If a potential solution involves reinforcement from a neighboring area, e.g. Woodstock, the study area will be expanded to include that area when studying that particular solution.

Figure 2 – Brant Area Transmission System



3.2 Key Assumptions and data

The study will consider the following key assumptions.

- Demand Data
  - Historical hourly demand data, in MW, from 2007 to 2012
  - Normal weather to extreme weather adjustment factor Coincident factors for Brant area summer peak demand
- Distributed Generation (DG)
  - Existing DG facilities, including merchant generators and Non-Utility Generation (NUG) contracts

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[2] As Newton TS and Dundas #2 TS are not directly impacted by the supply issues associated with the Brant Area in this study, a detail assessment for those two stations is not required.

- Existing and committed renewable generation from FIT and non-FIT procurements
    - Existing RESOP (e.g. BGI Landfill) and under construction Load Displacement DGs (e.g. Ferrero)
    - Future district energy plans, CHP developments where appropriate

- Relevant community plans
    - Green Energy plans and community long-term energy objective plans, as applicable from Brant County, Brantford City, and other municipalities as needed.

- Conservation and Demand Management (CDM) Programs
    - Incorporation of actual LDC CDM Results from inception to 2013
    - Incorporation of OEB target CDM Results from 2013 through 2015
    - OPA-Contracted Province-Wide CDM Programs
    - OPA Demand-Response (DR) Programs
    - LDC Board-Approved CDM Programs
    - Long-term CDM forecast (2030 provincial target)

- Existing area network
    - Line ratings as per Hydro One database
    - Station ratings as per Hydro One and LDCs information
    - Capability as per current IESO PSS/E base cases

- Bulk System assumptions to be applied to the existing area network
    - Key transmission system interface assumptions

- Other assumptions, as applicable
    - LDCs load transfer capabilities
    - End-of-life/asset condition
    - Underutilized existing assets
    - LDCs expansion plans relevant to the study

3.3 Criteria to be used for the evaluation process

- Reliability Criteria (as per the Ontario Resource and Transmission Assessment Criteria)
    - Load supply capability
    - Load supply security/load restoration requirements as per Section 7.2

4. Activities and Primary Accountability

- Prepare draft Terms of Reference *(OPA)*

- Accept final Terms of Reference *(All)*

- Establish demand forecast *(LDCs and OPA)*

- Provide information on load transfer capabilities under normal and emergency conditions *(LDCs)*

- Establish existing, committed and potential DG including FIT and non-FIT uptake *(OPA and LDCs)*

- Provide information on Green Energy and other relevant community plans *(OPA and LDCs)*

- Complete system studies to identify supply capabilities *(OPA, Hydro One, IESO)*
    - Develop PSS/E base case
    - Including bulk system assumptions as identified in Key Assumptions
    - Applying reliability criteria as defined in the ORTAC

- Establish need *(All)*
    - Supply capacity
    - Load security and restoration
    - Performance

- Develop options *(All)*
    - Conservation options *(OPA and LDCs)*
    - Local generation option *(OPA and LDCs)*
    - Assess feasibility and provide budgetary cost estimates for transmission options *(Hydro One)*
    - Assess feasibility and provide cost estimate for accepted distribution options (*LDCs*)
    - Investigate the impact of transmission options on the ability of operation including protection and short-circuit implications *(Hydro One)*
    - Study impact of options on bulk system capability *(OPA, IESO)*

- Evaluate options *(All)*
    - Technical comparison and economic evaluation *(All)*
    - High-level environmental and social acceptance assessment *(Hydro One and LDC's)*
    - Affordability and cost allocation considerations *(All)*

- Integrate options of transmission, distribution and local generation *(All)*

- Recommendation of options/course of action (*All*)

- Development of implementation plan *(All)*

- Communication and stakeholder engagement *(All)*
    - Organize study team meetings when appropriate (*OPA*)
    - Communication with other stakeholders external to the working group will be held when appropriate *(All)*

5. Resources

5.1 Study Team

The core study team will consist of planning and engineering representative/s from the following organizations:

- Ontario Power Authority *(Team Lead)*
- Hydro One Transmission
- Brant County Power Inc.
- Brantford Power Inc.
- Hydro One Distribution
- Horizon Utilities Corporation[3]
- Independent Electricity System Operator

Input from other entities such as large transmission connected industrial customers to be sought by Hydro One as required.

Support from other groups as required.

5.2 Authority

Each entity involved in the study will follow its own internal process on the approval of the proposed implementation plan resulting from this study.

5.3 Funding

For the duration of the study process, each participant is responsible for their own funding as necessary, for the study work required to be completed.

6. Deliverables

- Terms of Reference
- Needs Screening Report
- Communication materials
- Study Report
- Recommendation Letters *(if needed)*
- Implementation Plan

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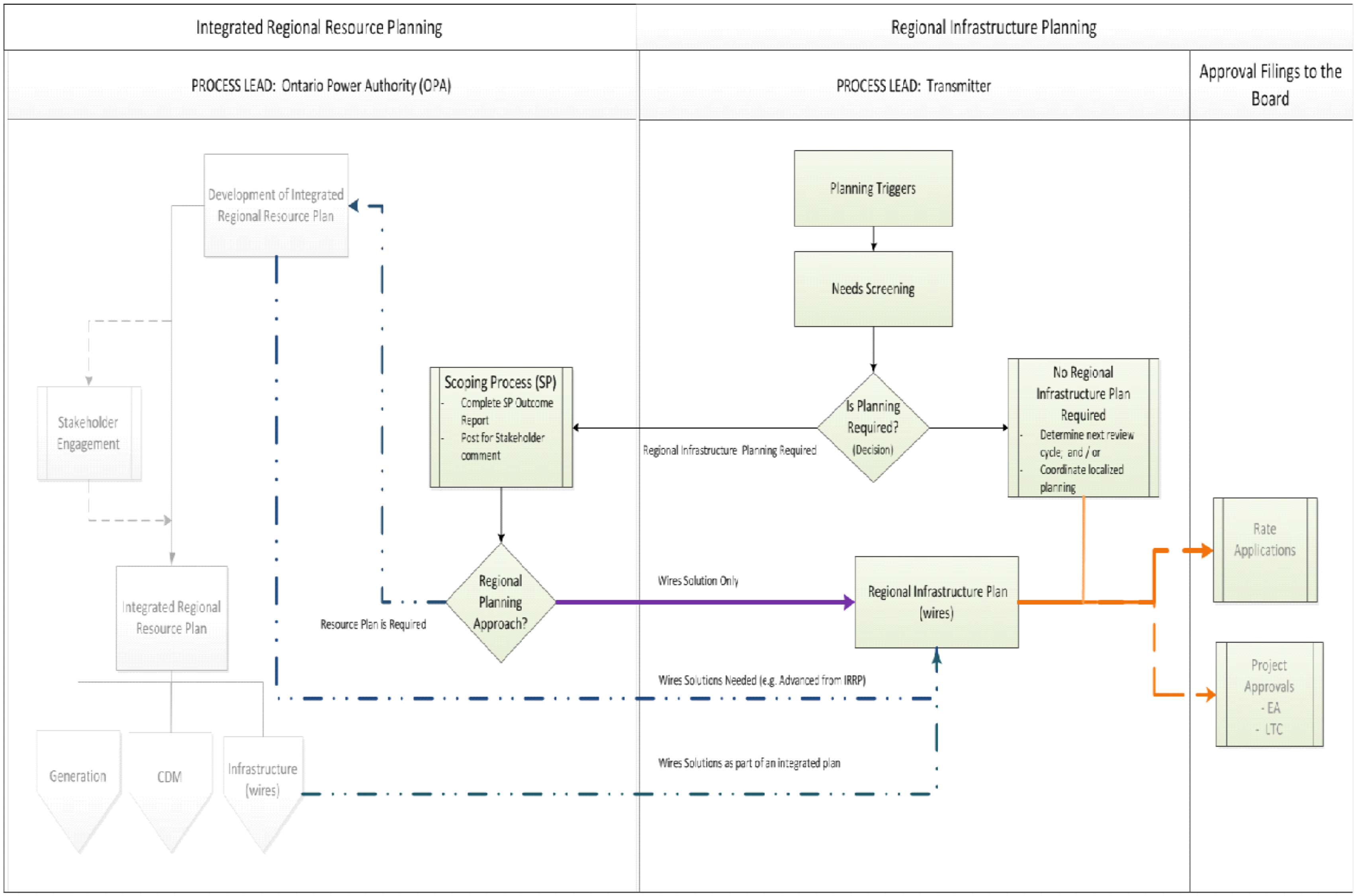
[3] Since Horizon Utilities Corporation (Horizon) has not been directly impacted by the supply issues associated with the Brant Area in this study. The involvement is optional and Horizon will be informed of any pertinent updates with regards to this study.

7. Study Schedule

Initial draft Schedule, developed June 07, 2013

									2014					
			Q3			Q4			Q1			Q2		
	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Finalize Terms of Reference		■												
Establish demand data		■	■											
Provide information on load transfer capabilities		■	■											
Establish DG information		■	■											
Provide information on Green Energy and/or relevant community plans		■	■											
Complete system studies to identify supply capabilities		■	■	■										
Develop options including Transmission, Distribution and local Generation		■	■	■										
Establish need				■										
Evaluate options					■	■								
Integrate options					■	■								
Communication with stakeholders					■	■	■	■	■	■	■	■	■	
Recommend preferred option											■			
Develop Implementation Plan												■		
Finalize study report													■	
Coordination with Distribution and Transmission rate cases (if applicable)		■	■	■	■	■	■	■	■	■	■	■	■	

REGIONAL PLANNING PROCESS



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BOMA-6_Attch 4_Needs Screening Report

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NEEDS SCREENING REPORT

Region: Burlington to Nanticoke

Date: May 23, 2014

Prepared by: Burlington to Nanticoke Study Team

Burlington to Nanticoke Region Needs Screening Study Team Members

Study Team	
Company	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Khurram Makhdoom Devinder Bahra
Ontario Power Authority	Bob Chow
Independent Electricity System Operator	Phillip Woo
Brant County Power Inc.	Michael Desroches
Brantford Power Inc.	Mark Simpson
Burlington Hydro Inc.	Joe Saunders
Haldimand County Hydro Inc.	Paul Heeg
Horizon Utilities Corporation	Richard Bassindale
Hydro One Networks Inc. (Distribution)	Charlie Lee
Norfolk Power Distribution Inc.	Ernie Vidovic
Oakville Hydro Electricity Distribution Inc.	Mike Brown Dan Steele

Disclaimer

This Needs Screening Report was prepared for the purpose of identifying potential needs in the Burlington to Nanticoke Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Screening Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Screening 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 Screening 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 Screening Report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the Needs Screening 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 Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

NAME	Burlington to Nanticoke Region		
LEAD	Hydro One Networks Inc. ("Hydro One")		
REGION	Burlington to Nanticoke		
START DATE	March 24, 2014	**END DATE**	May 23, 2014

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the Burlington to Nanticoke Region, determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

2. REGIONAL ISSUE/TRIGGER

The Needs Screening for the Burlington to Nanticoke Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. Burlington to Nanticoke Region belongs to Group 1 and the Needs Screening for this Region was triggered on March 24, 2014 and was completed on May 23, 2014.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the OPA, the IESO, and Hydro One transmission provided information for the Burlington to Nanticoke Region. The information included historical load, load forecast, Conservation and Demand Management (CDM), Distributed Generation (DG), load restoration and performance information along with end-of-useful-life of any major equipment. See Section 4 for further details.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

I Regional Supply Capacity

A. 230kV Regional Supply

- Over the study period no overload or capacity need was identified for the loss of single 230kV circuits in the region.

B. 230/115kV Autotransformers

- No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer.
- For the loss of two autotransformers at Burlington TS (low probability) there may be situations when load restoration as per the IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) may not be met.

C. 230kV and 115kV Connection Facilities

Brant Area

- The Brant Area sub-region currently has an OPA-led IRRP study underway. The results of this area IRRP will be later appended to the regional IRRP.
- Currently, IRRP study has identified voltage and capacity issues in the near-term on 115kV transmission circuits B12/B13. The OPA has issued a handoff letter to Hydro One to develop and implement a plan with relevant LDCs (Brantford Power and Brant County Power) to provide reactive support in the Brant area.

Burlington-Hamilton Area

There are several needs emerging in this area. Some of the needs identified during the study period include, but may not be limited to:

- Transmission circuits B7/B8 loads may reach their thermal capacity.
- Mohawk TS load is currently at its normal supply capacity, and will exceed capacity.
- At Dundas TS existing capacity of the two DESNs is expected to be sufficient over the study period. Load balancing between the two DESNs is required to mitigate overloading on one of the DESNs.

- Nebo TS (T3/T4 DESN) will require a switchgear to utilize the spare windings of transformers.
- Bronte TS may reach its normal supply capacity before the end of the study period.

Beach Area

- There are no significant needs in this area over the study period.

Caledonia-Norfolk Area

- Under peak load conditions and single contingency, there will be low voltage issues at Norfolk TS and Bloomsburg MTS.

II System Reliability, Operation And Load Restoration

Generally speaking, there are no significant system reliability and operating issues for one element out of service. However, for the loss of two elements, load restoration as per ORTAC criteria may not be met. Further study is required.

III Aging Infrastructure And Replacement Plan Of Major Equipment

During the study period, plans to replace major equipment do not affect the needs identified with the exception of the replacement of transformers at Mohawk TS.

7. RECOMMENDATIONS

Based on the assessment, the study team's recommendations are as follows:

a) At this time, some of the potential needs identified do not require further regional coordination. These potential needs can be adequately and more efficiently addressed through localized planning between Hydro One Networks Inc. and the LDCs. See Sections 6 and 7 for further details.

b) Coordinated regional planning is further required for some of the needs and OPA to undertake Scoping Assessment. See Sections 6 and 7 for further details.

TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the Burlington to Nanticoke Region ("Region") over the next ten years. The development of the Needs Screening 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 Board.

The purpose of this Needs Screening report is to undertake an assessment of the Burlington to Nanticoke Region, determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a wires-only only solution is necessary such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required. This report was prepared by the Burlington to Nanticoke Region Needs Screening study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by the LDCs, the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Burlington to Nanticoke Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Ontario Power Authority
3.	Independent Electricity System Operator
4.	Brant County Power Inc.
5.	Brantford Power Inc.
6.	Burlington Hydro Inc.
7.	Haldimand County Hydro Inc.
8.	Horizon Utilities Corporation
9.	Hydro One Networks Inc. (Distribution)
10.	Norfolk Power Distribution Inc.
11.	Oakville Hydro Electricity Distribution Inc.

2 REGIONAL ISSUE/TRIGGER

The Needs Screening for the Burlington to Nanticoke Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Burlington to Nanticoke Region belongs to Group 1. The Needs Screening for this region was triggered on March 24, 2014 and was completed on May 23, 2014.

The Burlington to Nanticoke Region can be divided into four electrical areas: Brant, Caledonia-Norfolk, Burlington-Hamilton, and Beach. The Brant Sub-Region currently has an IRRP under development, which was initiated prior to the new Regional Planning process.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the Burlington to Nanticoke Region over an assessment period of 2014 to 2023. The scope of the Needs Screening includes a review of system capability which covers transformer station loading and transmission line thermal and voltage analysis. System reliability, operation, load restoration and asset sustainment issues were also reviewed as part of this screening.

3.1 Burlington to Nanticoke Region Description and Connection Configuration

The Burlington to Nanticoke Region is located in Southern Ontario and comprises the municipalities of Burlington, Hamilton, Oakville, Brantford, Brant County, Haldimand County, and Norfolk County. The boundaries of the Burlington to Nanticoke region and its four sub-regions are shown in Figure 1.

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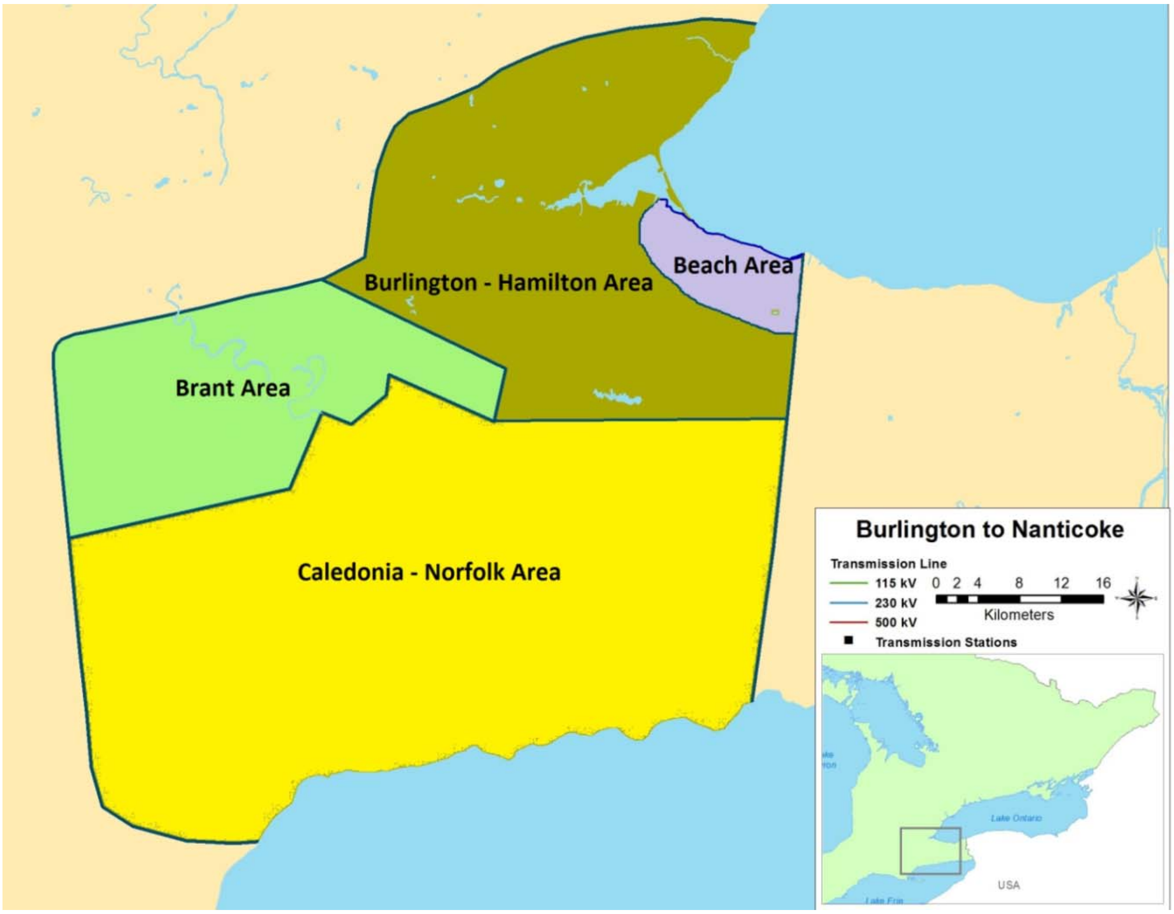

Figure 1: Burlington to Nanticoke Regional and Area Boundaries

The Burlington to Nanticoke 230kV and 500kV systems are part of East-West bulk power system transfers mainly from the generation located in Western Ontario toward the Greater Toronto Area (GTA). This region has two 500kV stations, Nanticoke TS and Middleport TS, interconnected through two 500kV circuits and connected to 500kV Longwood TS and Milton TS. Both of these 500kV stations have transformation capacities to 230kV systems. The Burlington to Nanticoke Region's 230kV system has three autotransformer stations at Burlington TS, Beach TS, and Caledonia TS supplying the 115kV transformer stations. For Needs Screening, Dunnville TS has been included in the Niagara Region (Group 3, Region 17) instead of the Burlington to Nanticoke Region (Group 1, Region 1) – a change to the May 17, 2013 OEB Planning Process Working Group Report

The 230kV interconnections of Burlington to Nanticoke Region to the rest of system consist of two circuits to Detweiler TS, three circuits to Buchanan TS and seven circuits to Beck TS. The 115kV circuits are supplied from Burlington TS, Beach TS and Caledonia TS. A single line diagram of the 500kV, 230kV and 115kV systems in the Burlington to Nanticoke Region is shown in Figures 2 and 3.

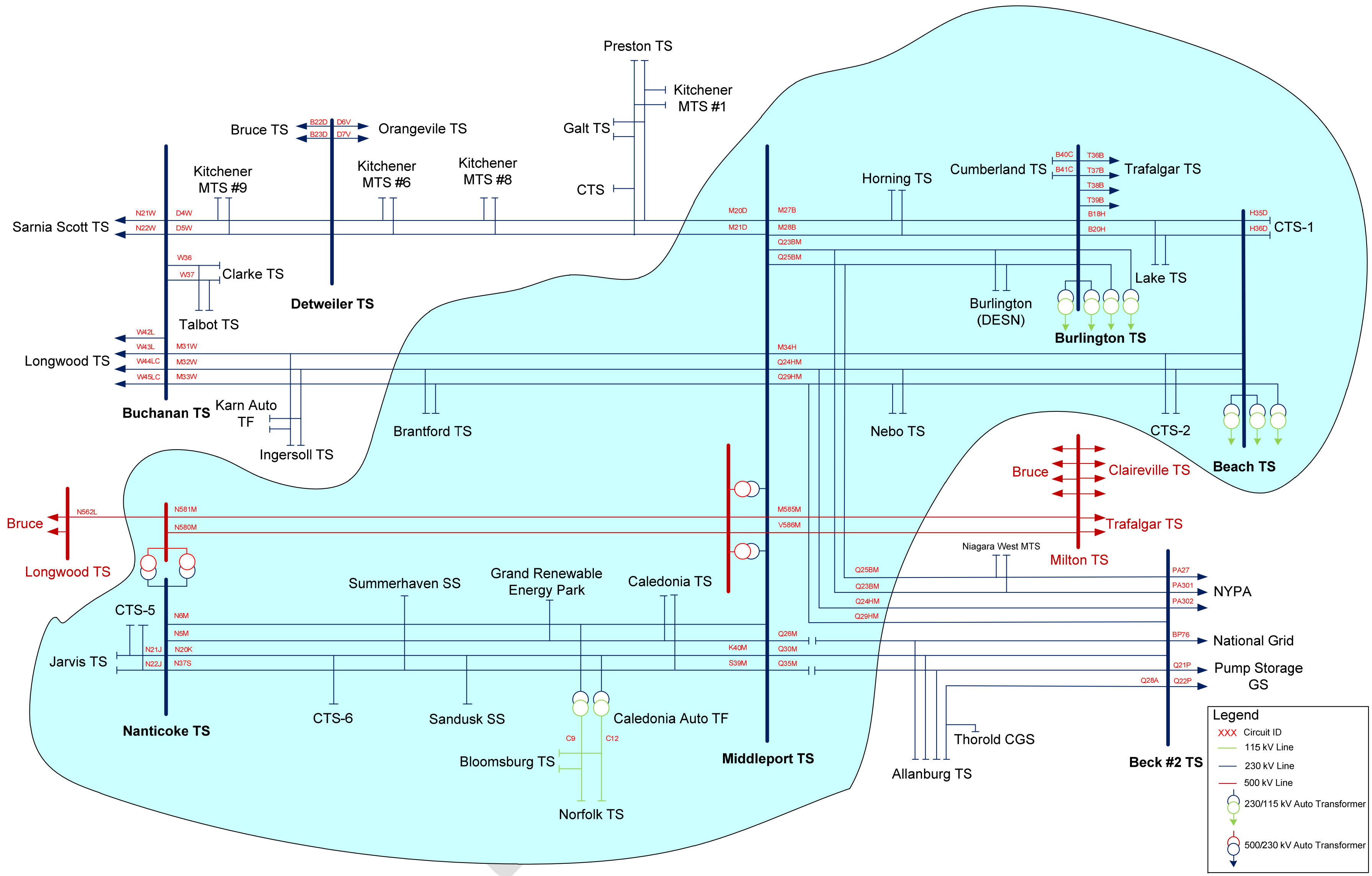

Figure 2: Burlington to Nanticoke Region – 230kV and 500kV Single Line Diagram

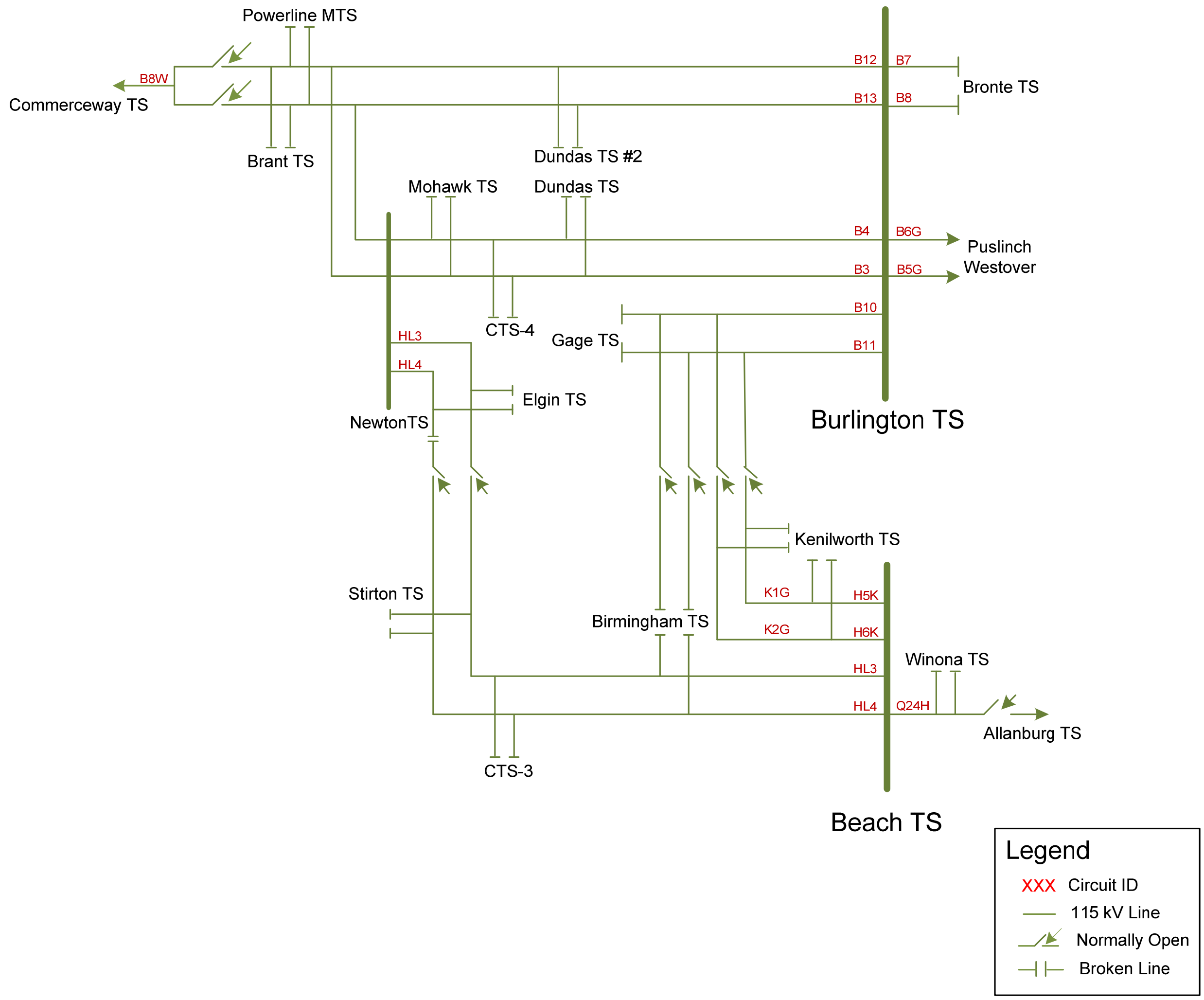

Figure 3: Burlington and Beach 115kV Single Line Diagram

3.2 Electrical Areas

Based on the geographical location and supply configuration, the Burlington to Nanticoke Region was divided into the following electrical areas for the purpose of this assessment:

- Brant Area
- Burlington-Hamilton Area
- Beach Area
- Caledonia-Norfolk Area

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information and data to Hydro One:

- IESO provided:
    - i. Historical regional coincident peak load and station non-coincident peak load.
    - ii. List of existing reliability and operational issues.
- LDCs and Transmission Connected Customers provided historical (2011-2013) net load and gross load forecast (2014-2023).
- Hydro One provided transformer, station, and line ratings.
- OPA provided Conservation and Demand Management (CDM) and Distributed Generation (DG) data.
- Any relevant planned transmission and distribution investments were provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per data provided by the study team, the load in the Burlington to Nanticoke Region is expected to grow at an approximate rate of 1.1% annually over the long term. The growth rates vary across the Region, from approximately 0.5% in the Beach Area to 2.8% in the Brant Area. The individual area load growth rates over the 2013-2023 period are given in Table 2:

Table 2: Annual Load Growth Rates for Burlington to Nanticoke Region

Area	Approximate %Growth Rate 2013-2018	Approximate % Growth Rate 2018-2023
Brant Area	2.8	2.5
Burlington-Hamilton Area	1.3	1.2
Beach Area	0.5	0.5
Caledonia-Norfolk Area	1.0	1.0
Overall Area	1.2	1.1

The Needs Screening assessment considered gross loads at individual stations based on the 2013 summer peak non-coincident load and the peak summer load forecast for stations within the Region. The station load forecast was developed by applying load growth rates derived from the LDC’s load forecast.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Screening assessment:

1. The Region is summer peaking, so this assessment is based on summer peak loads.
2. Forecast loads are based on the anticipated forecast growth rates provided by the Region's LDCs using 2013 peak summer load as the reference point.
3. The 2013 historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
4. A uniform and proportionated load growth is assumed over the study period.
5. Stations having negative load growth over the study period are assumed to have steady load.
6. In developing a worst-case scenario, DG and CDM contributions were not considered.
7. Review and assess impact of any on-going or planned development project in Burlington to Nanticoke 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 autotransformers, cables and stations.
9. Station capacity adequacy is assessed assuming a 90% lagging power factor and non-coincident station loads.
10. To identify the emerging needs in each area, the study was performed observing all elements in service and one element out of service. Any known issues with two elements out of service have been provided by the IESO.
11. Transmission line adequacy to be assessed using non-coincident peak station loads in the region.
12. Transmission adequacy assessment is primarily based on:
    - 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-time emergency (LTE) ratings and transformers within their summer 10-Day limited time ratings (LTR).
    - All voltages must be within pre- and post-contingency ranges as per ORTAC criteria.

This Needs Screening assessment was conducted to identify emerging needs and determine whether or not further coordinated regional planning should be undertaken for the Region or electrical areas (sub-regions). It is expected that further studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements including loss of two elements.

6 RESULTS

This section summarizes the results of the Needs Screening in the Burlington to Nanticoke Region.

6.1 Regional Supply Capacity

6.1.1 230kV Regional Supply

The 230kV transmission system in the Region consists of Middleport TS connected to other stations in the Region by one circuit to Beach TS, two circuits to Burlington TS, one circuit to Beck TS, two circuits to Detweiler TS, three circuits to Buchanan TS and by another four circuits to Nanticoke TS. In addition, Middleport TS is connected to Beck TS through four circuits. Of these four circuits, two are tapped to Burlington TS and the remaining two to Beach TS. The Burlington TS and Beach TS are also connected to each other by two 230kV circuits.

The power flows on the 230kV circuits in the Region are mainly dependent on the Bulk system flows. Over the study period, no overloads were observed on 230kV lines in Burlington to Nanticoke Region for the loss of a single 230kV circuit. In some cases, the loss of a transmission structure with more than one circuit will result in loss of load.

6.1.2 230/115kV Autotransformers

The Region has three 230/115kV autotransformer stations in the Burlington-Hamilton, Beach and Caledonia-Norfolk areas. There are no overloading issues expected over the study period for the loss of a single autotransformer. This will require reassessment in the next regional planning cycle.

It has been identified that for the loss of two autotransformers at Burlington TS (low probability) there may be overloading and situations when load restoration as per ORTAC may not be met. Additional studies are required to examine the impact of the loss of two autotransformers.

6.1.3 230kV and 115kV Connection Facilities

Brant Area

The Brant area sub-region currently has an OPA-led IRRP study underway. The results of this IRRP will later be appended to the regional IRRP.

Currently, the IRRP study has identified voltage and capacity issues in the near-term on 115kV transmission circuits B12/B13. The OPA has issued a handoff letter to Hydro One to develop and implement a plan to provide reactive support in the area.

Burlington-Hamilton Area

There are several needs emerging in this area. Some of the needs identified during the study period include, but may not be limited to:

- Transmission circuits B7/B8 may reach their thermal capability and/or can be constrained by voltage issues and require further assessment.

- Mohawk TS is currently above its normal supply capacity (i.e. 10-day LTR). This is a known issue which had been discussed with the LDC and both loading and growth is being monitored. DG and CDM initiatives may help address the issue and/or defer needs.
- At Dundas TS there are two DESNs (Dundas TS and Dundas TS#2) with existing capacity expected to be sufficient over the study period. However, distribution investments are required to balance load amongst the two DESNs through load transfers.
- Nebo TS (T3/T4) is expected to have sufficient station capacity over the study period. However, a second switchgear will be required to utilize the spare winding of transformers.
- Bronte TS may reach its normal supply capacity before the end of the study period and require further assessment.
- Historical data shows that power factor at Cumberland TS may be below ORTAC criteria under peak load conditions and require further assessment.

Beach Area
There are no significant needs in this area over the study period. However, historical data shows that the power factor at Beach TS (115kV) and Kenilworth TS may be below ORTAC criteria under peak load conditions and require further assessment.

Caledonia-Norfolk Area
Under peak load conditions and single contingency there can be low voltage issues at Norfolk TS and Bloomsburg MTS. Additional reactive support at Bloomsburg MTS may mitigate this issue.

6.2 System Reliability, Operation and Load Restoration

Generally speaking, there are no significant system reliability and operating issues for one element out of service.

For the loss of two elements or for a single contingency taking two circuits out (on a single tower), load restoration under peak load conditions as per ORTAC criteria may not be met and require further study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

During the study period:

- None of the autotransformers are expected to reach the end of their useful life.
- Upgrades or refurbishment of Gage TS and Elgin TS are currently planned within the study period. These reconfigurations are not expected to affect any capacity needs identified in the region.
- Replacement of transformers at Mohawk TS is planned in the near term and may address capacity needs at the station.
- No high voltage cables in the area are expected to reach the end of life within the study period.

7 RECOMMENDATIONS

The study team's recommendations are as follows:

a) At this time, the following potential needs identified above do not require further regional coordination. Rather, these potential needs can be adequately and more efficiently addressed through localized planning between Hydro One Networks Inc. and the relevant LDCs.

Burlington-Hamilton Area

- Dundas TS – distribution reconfiguration(s) and/or investments to balance load amongst the two DESNs is required.
- Nebo TS (T3/T4 DESN) – a second switchgear to utilize the spare winding of transformers.
- Cumberland TS – assessment of power factor at Cumberland TS to meet ORTAC criteria under peak load conditions.

Caledonia-Norfolk Area

- Bloomsburg TS – Additional reactive support at Bloomsburg MTS may resolve this issue, and further assessment by the transmitter and the LDC should be undertaken.

Beach Area

- Assessment of power factor at Beach TS (115kV) and Kenilworth TS to meet ORTAC criteria under peak load conditions.

b) Coordinated regional planning is further required by the OPA to undertake Scoping Assessment for the remaining needs identified in Section 6 of this report and develop study scope. As part of its Scoping Assessment process, the OPA will determine if the OPA-led IRRP process and/or transmitter-led RIP process (for wires solutions) should be undertaken to address these potential needs in this Region.

The Brant area sub-region currently has an OPA-led IRRP study underway. OPA will later append the results of this sub-region IRRP to the Regional IRRP.

8 NEXT STEPS

Following the Needs Screening process, the next regional planning step, based on the results of this report, is for:

a) Hydro One Transmission and relevant LDCs to further assess and develop local wires solutions in Section 7.a; and

b) OPA to initiate a Scoping Assessment(s) to determine which of the needs in Section 7.b require an IRRP and/or RIP.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) OPA's February 6, 2014 letter to Hydro One: Brant Area Regional Planning- Initiating the implementation of the Near Term Wire(s) Solutions.

iii) IESO 18-Month Outlook

iv) SIA - Powerline MTS- CAA ID 2005-196

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CGS	Customer Generating Station
CIA	Customer Impact Assessment
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
LV	Low-voltage
MTS	Municipal Transformer Station
MVA	Mega Volt-Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council
NS	Needs Screening
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code

BOMA-7

Reference:

Ex1, T2, Sch 6, p1 - Summary of the Plan

Preamble: "The other (1-X) approach to IRM ratemaking will not result in sufficient regulated cash flow to support the rising investment requirements."

(a) Please provide a quantitative analysis to demonstrate the truth of the above statement.

(b) Please show what reductions in proposed CAPEX/OMA would be necessary to match the available cash flow from a traditional 1-X IRM using accepted Board numbers for inflation, productivity and stretch factors.

The above analysis should consider the particulars of Horizon's capital structure and dividend policy

(c) Please confirm that the proposed IRM plan is essentially a 5 year cost of service plan. If not, please provide the characteristics that make it different from a 5 year cost of service plan and from 5 successive one year cost of service plans, Please explain fully. Illustrate the differences where appropriate.

Response:

a) Please refer to 1-BOMA-7 Attachment 1 ("1-BOMA-7 Attch 1"; attached). This exhibit is identical to that provided in the overview section of the response to 1-EP-3 (1-EP-3 Attachment 2) other than Board numbers have been provided for inflation, productivity and stretch factors and the relative mix of labour and non-labour OM&A and CAPEX. The Board factors for 2016 through 2019 have been assumed to remain constant forward from the last year of values provided in Appendix B of the Report of the Board: *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379).

1-BOMA-7 Attch-1 effectively estimates the difference between the Revenue Requirement sought for 2015 through 2019 in the Application and a Revenue Requirement derived using the IPI-X IRM using Board parameters and factors. The results demonstrate that Horizon Utilities would have a cumulative shortfall in regulated cash flow of $29.2MM over the 2015 through 2019 IR period relative to the investment requirements provided for in the

Application. The $29.2MM shortfall is arrived by aggregating line (iii) “Real RR Growth – Application vs. Price Cap (C = A – B) (rounded)” for each of 2015 through 2019 as follows:

2015 - $4,000,000;

2016 - $6,300,000;

2017 - $6,500,000;

2018 - $5,700,000;

2019 - $6,700,000.

b) The analysis in a) also informs the amount of reduction in CAPEX/OMA that would be required to match cash flow from traditional annual IPI-X IRM adjustments.

OMA Reduction

OMA is recovered from ratepayers as a combination of a: i) dollar-for-dollar equivalent basis to OMA; ii) cost of capital and related payments in lieu of taxes imputed on the contribution of OMA to the Working Capital Allowance. On this basis and holding CAPEX constant at the amount provided for in the Application, OMA would need to be reduced by an average annual amount of $5,787,000 in each of 2015 through 2019 to result in an aggregate reduction across these years of $29.2MM (refer to 1-BOMA-7 Table 1 below).

HORIZON UTILITIES CORPORATION						1-BOMA-7 Table 1
Response to 1-BOMA-7b)						
($000s)						
Assumptions:						
OMA - Annual	5,787					
Working Capital Rate	12.70%					
PILs Rate	26.25%					
Deemed Debt %	60.00%					
Deemed Equity %	40.00%					
	2015	**2016**	**2017**	**2018**	**2019**	**Totals**
Cost of Capital						
Debt	3.38%	3.38%	3.38%	3.53%	3.65%	
Equity	9.36%	9.36%	9.36%	9.36%	9.36%	
Revenue Requirement						
OM&A	5,787	5,787	5,787	5,787	5,787	28,937
Cost of Capital:						
Debt	15	15	15	16	16	76
Equity	28	28	28	28	28	138
PILs Gross-Up	10	10	10	10	10	49
Total	5,840	5,840	5,840	5,840	5,841	29,200
Working Capital Impact	735	735	735	735	735	

CAPEX Reduction

CAPEX is recovered from ratepayers as a combination of the cost of capital on rate base and depreciation. Essentially, the amount of Revenue Requirement required to finance CapEx is similar to the amount of mortgage payment required in each year to finance a purchase over an extended period of time (such as its depreciable life) with interest serving as a proxy for cost of capital and principal payments serving as a proxy for depreciation. On this basis, the ratio of Revenue Requirement to finance CapEx is much lower than that required to finance OMA. In other terms, a dollar of revenue requirement reduction results in a much larger reduction of CAPEX.

It is very difficult to precisely model the amount of CAPEX reduction required to match the cash flow as requested in this interrogatory for a variety of reasons including:

- modelling the impact on revenue requirement of the runoff of the 2014 closing rate base in isolation of the impact of the prospective CAPEX program;
- shaping the prospective CAPEX program to conform to the match the annual cash flow from traditional IPI-X IRM adjustments.

Consequently, Horizon Utilities has taken the approach of modeling the impact of a reduction in rate base (average net fixed assets) from that requested in this Application that would match the revenue requirement cash flow from traditional IPI-X IRM adjustments. Such modeling provides the level amount of annual CAPEX reduction in order to achieve the corresponding reduction in rate base. The modeling assumes that: i) OMA is held constant at levels provided for in the application; and ii) CAPEX additions have 40-year depreciable lives.

On this basis, Horizon Utilities has modelled the amount of CAPEX additions and resulting rate base growth that may be financed by the difference between: i) the aggregate revenue requirement provided in the Application for 2015 through 2019; and ii) the aggregate revenue requirement conforming to traditional IPI-X IRM adjustments.

The analysis in a) demonstrates that Horizon Utilities would need to reduce the aggregate revenue requirement provided in this Application from 2015 to 2019 by $29,200,000 in order to match the annual cash flow from traditional IPI-X IRM adjustments.

1-BOMA-7 Table 2 (below) demonstrates that $29,200,000 of Revenue Requirement is required to finance the depreciation, cost of capital, and payments in lieu of taxes (corresponding to Tables 5-38 to 5-32 in the Application) corresponding to annual CAPEX additions of $30,404,000 (aggregate of $144,067,000) and the resulting $129,025,000 of growth in average net fixed assets (rate base) from 2015 to 2019. This analysis assumes: i) distribution assets with a 40-year useful life included in Class 47 for purposes of capital cost allowance; and ii) that there is a sustaining level of annual revenue requirement beyond 2019 to support the ongoing depreciation and cost of capital associated with the remaining lives of the additions from 2015 through 2019. Obviously, with respect to ii), the $29,200,000 of aggregate Revenue Requirement from 2015 through 2019 only provides financing for the first 1 to 5 years of the 40 year depreciable lives of these assets.

HORIZON UTILITIES CORPORATION					1-BOMA-7 Table 2	
Response to 1-BOMA-7b)						
($000s)						
Assumptions:						
Annual CapEx	30,404					
Depreciable Life (Years)	40					
CCA Rate	8.00%					
PILs Rate	26.25%					
Deemed Debt %	60.00%					
Deemed Equity %	40.00%					
	2015	**2016**	**2017**	**2018**	**2019**	**Totals**
Fixed Asset Continuity						
Opening Balance	-	30,024	59,287	87,790	115,534	
Additions	30,404	30,404	30,404	30,404	30,404	
Depreciation	(380)	(1,140)	(1,900)	(2,660)	(3,420)	
Closing Balance	30,024	59,287	87,790	115,534	142,517	
Average Balance	15,012	44,655	73,539	101,662	129,025	
UCC Continuity						
Opening	-	29,187	56,040	80,744	103,472	
Additions	30,404	30,404	30,404	30,404	30,404	
CCA	(1,216)	(3,551)	(5,699)	(7,676)	(9,494)	
Closing	29,187	56,040	80,744	103,472	124,382	
Cost of Capital						
Debt (Exhibit 5)	3.38%	3.38%	3.38%	3.53%	3.65%	
Equity (Exhibit 5)	9.36%	9.36%	9.36%	9.36%	9.36%	
Revenue Requirement						
Depreciation	380	1,140	1,900	2,660	3,420	9,501
Cost of Capital:						
Debt	304	906	1,491	2,153	2,826	7,680
Equity	562	1,672	2,753	3,806	4,831	13,624
PILs Gross-Up (1)	(98)	(263)	(372)	(430)	(442)	(1,606)
Total	1,149	3,455	5,773	8,189	10,634	29,200
PILs Calculation						
Cost of Equity Capital	562	1,672	2,753	3,806	4,831	13,624
Add:						
Depreciation	380	1,140	1,900	2,660	3,420	9,501
Deduct:						
CCA	(1,216)	(3,551)	(5,699)	(7,676)	(9,494)	(27,636)
PILs Income	(274)	(739)	(1,046)	(1,209)	(1,243)	(4,511)
PILs before Gross-Up	(72)	(194)	(275)	(317)	(326)	(1,184)
PILs Gross-Up	(98)	(263)	(372)	(430)	(442)	(1,606)

In other terms, Horizon Utilities would need to reduce its annual CAPEX program by $28,813,000 from 2015 to 2019 in order to achieve a corresponding reduction of $122,277,000 of rate base that results in an aggregate 5-year reduction of revenue requirement cash flow by $29,200,000; which matches the annual cash flow from traditional IPI-X IRM adjustments. Clearly, this would not be prudent whatsoever given the magnitude of CAPEX requirements and corresponding urgency for such articulated in Exhibit 2 of the Application.

The capital structure and dividend policy of Horizon Utilities are not relevant for purposes of this analysis. The ratemaking policies of the Ontario Energy Board effectively deem the capital structure of the utility for ratemaking purposes and corresponding components of cost of capital recognizing that investors must be compensated for their investment to support a sustainable electricity industry (i.e., Fair Return Standard). The cash flows supporting these long-term investments are derived through distribution rate revenue. Investment cannot be supported otherwise. Consequently, it is appropriate that the above analysis is based on cash flows derived from rate revenue. The response to 5-EP-46 may provide further context in this regard.

c) Horizon Utilities' Application is a Custom IR Application. The Report of the Board - *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* ("RRFE") identified that on the Custom IR methodology, "this rate-setting method is intended to be customized to fit the specific applicant's circumstances" and, further, "The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels". Horizon Utilities has customized the Application to specifically address the needs of the organization and its customers. In doing so, it has chosen to frame it as a series of revenue requirements, subject to certain annual adjustments and possible reopeners if warranted.

Notable high level differences between the series of revenue requirements approach compared to a cost of service approach are that: the former leverages the 5 year Distribution Plan; it provides flexibility in pacing CAPEX and other expenditures; it is not subject to specified stringent filing requirements; and it is evaluated on the objectives and requirements enunciated in the RRFE as a Custom IR application.

BOMA-7_Attch 1

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HORIZON UTILITIES
Rate Revenue Analysis
2014 to 2019

1-BOMA-7 Exh 1

Rate Revenue Trend Analysis: Forecast vs. Price Cap
Board Total Productivity Factor

		2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
	Rate Revenue ("RR") Analysis - Actual and Forecast per Application						
(i)	**Total RR - including Smart Meters (A)**	**$ 107,230,228**	**$113,490,384**	**$118,628,501**	**$121,743,444**	**$123,920,317**	**$127,881,899**
	Customer/ Connections Counts (D)	241,692	243,319	245,123	247,036	249,021	250,909
	Total RR/ Customer - Application	$ 443.66	$ 466.43	$ 483.95	$ 492.82	$ 497.63	$ 509.67
	Year over Year Change in RR/ Customer		$ 22.76	$ 17.53	$ 8.86	$ 4.81	$ 12.04
	Cumulative/ Permanent Change in RR/ Customer Cost Structure		$ 22.76	$ 40.29	$ 49.15	$ 53.97	$ 66.01
	Customer Growth Rate - Annual		0.67%	0.74%	0.78%	0.80%	0.76%
	RR/ Customer Growth Rate per Application						
	Year over Year per Application		5.13%	3.76%	1.83%	0.98%	2.42%
	Cumulative from 2011 Approved		5.13%	9.08%	11.08%	12.16%	14.88%
	CAGR - Total Actual RR Growth		5.13%	4.44%	3.56%	2.91%	2.81%
	RR Analysis - Price Cap vs. Application						
	Labour RR as % of Total RR		30.0%	30.0%	30.0%	30.0%	30.0%
	Non-Labour RR as % of Total RR		70.0%	70.0%	70.0%	70.0%	70.0%
	Labour inflation index (actual and forecast)		1.1%	1.7%	1.7%	1.7%	1.7%
	Non-Labour inflation index (application assumption)		1.8%	2.0%	2.0%	2.0%	2.0%
	Inflation (Actual/ Forecast Combined Labour and Non-Labour Index)		1.59%	1.91%	1.91%	1.91%	1.91%
	Productivity Factor		0.00%	0.00%	0.00%	0.00%	0.00%
	Stretch Factor		-0.15%	-0.15%	-0.15%	-0.15%	-0.15%
	Price Cap Index - Actual/ Forecast + X-Factor		1.44%	1.76%	1.76%	1.76%	1.76%
	Price Cap Index - Adjusted for Customer Growth		1.45%	1.77%	1.77%	1.77%	1.77%
	Price Cap RR/ Customer (on 2011 Approved) (E)	$ 443.66	$ 450.10	$ 458.08	$ 466.20	$ 474.47	$ 482.89
	Price Cap RR/ Customer Growth (Year over Year)		$ 6.43	$ 7.98	$ 8.13	$ 8.27	$ 8.41
	Price Cap RR/ Customer Growth (Cumulative)		$ 6.43	$ 14.41	$ 22.54	$ 30.81	$ 39.22
	Difference - Application vs. Price Cap RR (Cumulative)		$ 16.33	$ 25.88	$ 26.61	$ 23.16	$ 26.79
	CAGR - Price Cap RR/ Customer		1.45%	1.61%	1.67%	1.69%	1.71%
	Analysis of RR/ Customer Difference under Price Cap vs. 2011						
	Year over Year Change in RR/ Customer (Application)		$ 22.76	$ 40.29	$ 49.15	$ 53.97	$ 66.01
	Less: Net Inflationary Growth (Price Cap)		6.43	14.41	22.54	30.81	39.22
	Real Growth in RR/ Customer vs. 2011 Approved		$ 16.33	$ 25.88	$ 26.61	$ 23.16	$ 26.79
(ii)	**Projected RR under Price Cap (B = D * E) (rounded)**		**$109,500,000**	**$112,300,000**	**$115,200,000**	**$118,200,000**	**$121,200,000**
(iii)	**Real RR Growth - Application vs. Price Cap (C = A - B) (rounded)**		**$ 4,000,000**	**$ 6,300,000**	**$ 6,500,000**	**$ 5,700,000**	**$ 6,700,000**

BOMA-8

Reference:

Productivity (Ex4, T3, Sch4, p4, Table 4-43)

(a) Please provide the supporting calculations that underpin the dollar value of productivity gain you have shown in table 4-43.

(i) Show the calculation separately for each of the 10 horizontal lines, Construction and Maintenance, IT & Tech, Customer Service, Supply Chain Management and Finance.

(ii) Please justify your assumption that in every case the productivity driven savings will last throughout the IRM period.

(b) Given the importance of customer service to the "Horizon brand" as noted in the the 15th Annual Customer Satisfaction Study why would you contract out a portion of your customer service (call centre overload). Please provide a cost benefit analysis for that decision.

Response:

a) Horizon Utilities provides the details in support of the productivity achievements and their sustainability set out in Table 4-43. All operating expenditure reductions and process improvements have been implemented as permanent accomplishments and as such, result in sustained savings throughout the rate plan term.

Construction and Maintenance

For ease of reference, the productivity achievements in Construction and Maintenance shown in Table 4-43 are shown below.

Table 1: Productivity Achievements in Construction and Maintenance

Contruction & Maintenance	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Oper. Reductions	$ -	$ 100,000	$ 100,000	$ 300,000	$ 400,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Prod.Impr/Cap	$ -	$ 600,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000

The Construction and Maintenance department's operating expenditure reductions and productivity improvements were achieved primarily through the implementation of the Planning and Scheduling system, outsourcing of work associated with retirements, reduction in downtime, and improvement in attendance. Please refer to BOMA-8_Attch 1_Construction and Maintenance for more details on the calculations.

Operating Expenditure Reductions

In 2012, the Planning and Scheduling initiative produced operating expenditure reductions of $100,000. These savings were the result of reductions in planned overtime that was achieved by more efficiently matching work requirements to labour capacity on a daily, weekly and monthly basis.

In 2013, the $100,000 in savings from the reduction in overtime were sustained. These cost reductions will be sustained throughout 2014-2019.

In 2014, operating savings increased by $200,000 for a total of $300,000 as a result of a reduction in staff levels due to outsourcing. For every 1 FTE reduction in staff, operating expenditures and overhead costs are reduced by approximately $38,000.

In 2015, operating savings increased by $100,000 for a total of $400,000 as a result of staff reductions due to outsourcing.

In 2016 – 2019 the operating savings from staff reductions of 11 FTEs is sustained at $500,000.

Productivity Improvements/Capacity

Productivity improvements in Construction and Maintenance are measured in terms of a reduction in non-productive time associated with yard time, travel time, downtime, absenteeism, meetings, and inefficient use of training time. Time savings have been monetized and presented in dollars in the table. Construction and Maintenance has monetized one FTE as $100,000.

In 2012, the $600,000 productivity improvements were attributed to:

- Approximately 3500 hours of maintenance and service-related work was injected into the Trouble Crew schedule, with a corresponding reduction in downtime equivalent to 2 FTEs.

- Training time per employee was reduced from an average of 80 hours per year to about 40 hours per year which represents approximately 2 FTEs.

- A reduction in the average absenteeism rate per employee of approximately 3 days was achieved which represents approximately 2 FTEs.

In 2013 productivity increases by $1,120,000 to a total of $1,720,000 were due to:

- Yard time required by Supervisors and Crews to organize work for the day, and travel time from job-to-job and from job sites to service centers to pick up additional materials and equipment, were reduced on average by 21 minutes per person per day. This time was converted to productive time which represents an increase in capacity equivalent to approximately 6.7 FTEs.

- Time allocated to meetings was reduced by approximately 2700 hours which represents an increase in capacity equivalent to approximately 1.6 FTEs.

- Time allocated to training was reduced by 1300 hours representing an additional 0.7 FTEs available for productive work. On-line training and pre-packaged training materials that became available in 2013 allowed some training to occur on an ad hoc basis that could not be achieved in prior years. Refer to Exhibit 4, Tab 2, Schedule 2, page 41 for discussion about Horizon Utilities' eLearning tools.

- An additional 3200 hours of maintenance and service work was injected into the Trouble Crew work schedule representing a capacity contribution to productive work of 2 FTEs.

- An additional reduction in total absence time of approximately 300 hours was achieved, representing a capacity gain equivalent to 0.2 FTEs.

In 2014 to 2019 the productivity savings of $1,720,000 are sustained.

Information Systems and Technology

For ease of reference, the productivity achievements in Information Systems and Technology ("IST") shown in Table 4-43 are shown below.

Table 2: Productivity Achievements in Information Systems and Technology

Information Systems & Tech	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Oper. Reductions	$ -	$ -	$ 60,000	$ 200,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000
Prod.Impr/Cap	$ -	$ -	$ -	$ 140,000	$ 1,020,000	$ 1,020,000	$ 1,020,000	$ 1,050,000	$ 1,150,000

Productivity achievements in Information Systems and Technology from 2013 to 2019 are delivered from five key initiatives: IFS ERP Phase 1, IFS ERP Phase 2, IFS ERP Phase 3, IFS ERP Upgrade, and Enterprise Unified Communications as described in Exhibit 4, Tab 3, Schedule 4, Pages 30 to 35. The operating expenditure reductions and productivity improvements/cost avoidance from these initiatives will be sustained from the time of implementation through the 2019 test year. Please refer to BOMA-8_Attch 2_Information Systems and Technology for further details on the calculations.

Operating Expenditure Reductions

In 2013, IST operating expenditure reductions of $60,000 were delivered by the IFS ERP Phase 1 initiative. These savings were achieved through migration of the IFS ERP system to a cloud-based managed service that facilitated the elimination of one IST technical support FTE position, elimination of server hardware maintenance, and a reduction in depreciation expenses as explained in Exhibit 4, Tab 3, Schedule 4, Page 32, Lines 4 to 12.

In 2014, IST operating expenditures savings increase by $140,000 to $200,000. This further reduction is due to realization of the full year of savings related to IFS ERP Phase 1 of $170,000 and $30,000 in reduced software maintenance costs related to the IFS ERP Phase 2 removal of IFS custom modifications.

In 2015 through 2019, operating expenditure savings increase $20,000 to $220,000. This further reduction is due to realization of the full year of savings related to software maintenance costs realized from the IFS ERP Phase 2 removal of IFS custom modifications in 2014.

Productivity Improvements/Capacity

In 2014, the IST productivity improvement/cost avoidance achievements of $140,000 are derived from two initiatives: IFS ERP Phase 2, and IFS process improvements. The IFS ERP Phase 2 initiative described in Exhibit 4, Tab 3, Schedule 4, Page 32 delivers $30,000 in cost avoidance related to software maintenance on IFS custom modifications. The execution of four IFS process improvements deliver $110,000 based on reduced staff effort to complete the processes, and the hourly burden rate for the employees affected.

In 2015, IST productivity improvement achievements increase by $880,000 to $1,020,000 as a result of productivity improvements related to three initiatives. First, IFS ERP Phase 2 contributes an additional $10,000 related to a full-year of depreciation cost avoidance. Second, IFS ERP Phase 3 will deliver $590,000 in productivity improvements from eight process improvements that reduce transaction processing times. These productivity improvements are based on the fully burdened hourly rates of the staff that execute the transactions. Third, the Enterprise Unified Communications initiative detailed in Exhibit 4, Tab 3, Schedule 4, Pages 34 and 35 will deliver $280,000 of staff productivity, based on an average of 15 minutes of regained productivity per day for 100 employees, and the hourly burden rate for the employees affected.

In both 2016 and 2017, IST productivity improvements remain constant at $1,020,000.

In 2018, IST productivity improvements/cost avoidance increases by $30,000 to $1,050,000 related to future depreciation cost avoidance resulting from the 2014 IFS Phase 2 initiative. IFS modifications that were removed in 2014 reduce the cost of the 2018 IFS ERP Upgrade as the modifications do not have to be migrated.

In 2019, IST productivity improvements/cost avoidance increases by $100,000 to $1,150,000 as Horizon Utilities realizes the full-year impact of future depreciation cost avoidance achieved during the planned 2018 IFS ERP Upgrade initiative.

Customer Services

For ease of reference, the productivity achievements in Customer Services identified in Table 4-43 are shown below.

Table 3: Productivity Achievements in Customer Services

Customer Services	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Oper. Reductions	$ 25,000	$ 375,000	$ 710,000	$ 920,000	$ 985,000	$ 1,015,000	$ 1,045,000	$ 1,075,000	$ 1,105,000
Prod.Impr/Cap	$ 50,000	$ 425,000	$ 800,000	$ 1,300,000	$ 1,300,000	$ 1,320,000	$ 1,340,000	$ 1,350,000	$ 1,360,000

Operating expenditure reductions and monetized productivity improvements have been realized in Customer Services through three primary areas of focus:

- The implementation of e-mobile, a paperless work management system as identified in Exhibit 4, Tab 3, Schedule 4, Page 8;
- The outsourcing of MV-90 and Overflow Call Centre services as described in Exhibit 4, Tab 3, Schedule 4, Page 11; and
- Enhanced processes and increased automation in Customer Service as provided in Exhibit 4, Tab 3, Schedule 4, Page 13.

Please refer to BOMA-8_Attch 3_Customer Services for further details on the calculations.

Operating Expenditure Reductions

The initial implementation of e-mobile produced operating expenditure reductions of $25,000 in 2011. These savings were achieved through the elimination of one Meter Technician FTE in late 2011 and decreased paper and printing expenditures.

In 2012, Customer Services' realized operating expenditures reductions of $375,000 as a result of sustained and enhanced e-mobile productivity measures totaling approximately $200,000 including the permanent elimination of one FTE Meter Technician which began in 2011, the elimination of a clerical support position, the elimination of one cargo van from the fleet, and decreased paper and printing expenditures. Incremental operating expenditure reductions of approximately $175,000 were achieved in Customer Service through: the outsourcing of one MV-90 Operator which began in June 2012; savings in conventional meter reading due to the implementation of Smart Meters, favourable pricing negotiated with the meter reading service provider and negotiated contract changes which eliminated certain Horizon Utilities expenditures; reduction in overtime in the department; and, the provision of a new e-billing service for the City of Hamilton which reduced printing, paper, and mailing expenditures.

In 2013, Customer Services' operating expenditure reductions increased to approximately $710,000 primarily as a result of sustained process enhancements and headcount reductions introduced in 2011 and 2012. Incremental operating expenditure reductions were achieved through: the permanent elimination of one FTE General Clerk as of May 2013; changes to the scheduling of permanent part-time employees in the Call Centre from 30 hours to 25 per week at certain times of the year; the increase of accounts for a large multi-account customer which are included in Horizon Utilities electronic billing solution; which further reduced paper, printing, and postage costs; the termination of dedicated courier services to transport payments between Horizon Utilities drop-off locations to head-office; and increased customer subscription to e-billing services including epost which reduced Horizon Utilities' paper, printing and postage expenditures.

In 2014, Customer Services' operating expenditure reductions increase to approximately $920,000. Customer Services' productivity improvements are primarily as a result of the initiatives implemented in 2011, 2012, and 2013 being sustained in 2014 including the permanent reduction of four FTEs. Incremental operating expenditure reductions are being achieved through the expansion of the e-mobile paperless service order program to include additional service orders provided electronically on tablets which reduces paper and printing costs, and increased customer subscription of e-billing services which partially offsets the impact of the Canada Post postage increase as identified in Exhibit 4, Tab 3, Schedule 3, Page 41.

In 2015, Customer Services' operating expenditure savings will increase by $65,000 as compared to 2014. The headcount reductions and productivity improvements implemented in 2011 to 2014 will be sustained. Incremental savings will be primarily achieved through increase customer subscription in e-billing services and the implementation of Overflow Call Centre Service. Call Centre headcount is anticipated to decrease by 1 FTE in 2015 due to attrition. The equivalent hours will be transitioned to the Overflow outsourced service provider resulting in overall cost containment beginning in 2016.

In 2016, 2017, 2018, and 2019 Customer Services' will increase operating expenditure reductions by an additional $30,000 annually. The headcount reductions and productivity improvements implemented in 2011 to 2015 will be sustained. Incremental savings will be primarily achieved through increased customer subscription in e-billing services and the implementation of Overflow Call Centre Service. Call Centre headcount is anticipated to decrease by 1 FTE in each year between 2016 to 2018 due to attrition. The equivalent hours will be transitioned to the Overflow outsourced service provider resulting in overall cost containment to the department, net of increased Overflow Call Centre Service expenditures.

Productivity Improvements/Capacity

In 2011, Customer Services measured and monetized approximately $50,000 of productivity improvements including increased capacity and future cost avoidance. This was achieved primarily through the implementation of e-mobile which reduced the travel time to the office for field agents, enabled the use of automation which reduced clerical works, which resulted in the redeployment of one FTE clerical position.

In 2012, Customer Services increased productivity to $425,000. The productivity and capacity building initiatives from 2011 were sustained. Incremental productivity benefits were measured through: the expanded implementation of e-mobile to include the automation of the collection notice process; the elimination of tasks related to paper file management; the automated transfer of service order meter data to the Advanced Metering Infrastructure ("AMI") system; and process improvements stemming from field staff having access to tablets, eliminating the need to return to the office to access electronic files. Incremental productivity and increased capacity of approximately $125,000 was measured in Customer Service through: the elimination of dedicated time for Call Centre agents to perform administrative tasks including time card reporting; the termination of a "banked time" project which allowed Customer Service staff to bank time to be taken off later in the same year; the relocation of a General Clerk position to the St. Catharines office to enable continued provision of clerical functions without backfilling with a more expensive Customer Service Representative; and miscellaneous smaller initiatives to streamline processes including the automation of the move-in / move-out process.

In 2013, Customer Services productivity improvements increased to $800,000. The productivity building initiatives from 2011 and 2012 were sustained in the departments. Incremental productivity was primarily achieved through: the continued e-mobile enhancements which resulted in the additional redeployment of one FTE; automated report generation which enables additional capacity for supervisors; and the automation of certain meter reading processes and reporting. The productivity benefits realized due to outsourcing and customer service initiatives were sustained.

In 2014, Customer Services increased its productivity improvements to $1,300,000. The productivity building initiatives from 2011 to 2013 continue to be sustained. Incremental productivity will be primarily achieved through continued e-mobile enhancements which resulted in the redeployment of an additional 0.5 FTE to perform other required functionality in the department; the expansion of e-mobile to include reconnection service orders; and the implementation of additional automation which will streamline certain Customer Service processes including those related to the provision of collection notices.

In 2015 through to 2019, Customer Services will sustain the productivity benefits achieved in 2014 to the end of 2019. Additional modest incremental savings will be achieved through the continued implementation of small automation initiatives.

Supply Chain Management

For ease of reference, the productivity achievements in Supply Chain Management shown in Table 4-43 are shown below.

Table 4: Productivity Achievements in Supply Chain Management

Supply Chain Management	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Oper. Reductions	$ -	$ 20,000	$ 40,000	$ 80,000	$ 100,000	$ 100,000	$ 110,000	$ 120,000	$ 110,000
Prod.Impr/Cap	$ -	$ 20,000	$ 50,000	$ 90,000	$ 90,000	$ 100,000	$ 100,000	$ 120,000	$ 140,000

Operating expenditure reductions and monetized productivity improvements have been realized in Supply Chain Management through the following primary areas of focus:

- The implementation of a second Fleet Services shift as identified in Exhibit 4, Tab 3, Schedule 4, Page 27;
- The expansion of bar coding to manage fleet inventory as provided in Exhibit 4, Tab 3, Schedule 4, Page 27;
- The introduction of purchasing cards for certain facilities-related purchases as identified in Exhibit 4, Tab 3, Schedule 4, Page 27; and,
- Streamlined processes and reduction in meeting to increase capacity as provided in Exhibit 4, Tab 3, Schedule 4, beginning on Page 28.

Please refer to BOMA-8_Attch 4_Supply Chain Management for further details on the calculations.

Operating Expenditure Reductions

In 2012, operating expenditure reductions of $20,000 were due to the implementation of a second fleet services shift described on Exhibit 4, Tab 3, and Schedule 4. This initiative reduced the level of overtime required to maintain and repair the vehicles when they were available at the Nebo Road service center fleet garage. Operating expenditure reductions of $20,000 annually from this initiative will be sustained to 2019.

In 2013, operating expenditure reductions of $40,000 was due to two initiatives described on Exhibit 4, Tab 3, and Schedule 4. The implementation of a second fleet services shift in 2012 and the introduction of purchasing cards for facilities purchase under $1,000 in 2013. The increase of $20,000 in operating expenditure reductions is due to the reduction of purchase orders by introducing the “purchasing card” or “p-card” for facilities purchases.

In 2014, operating expenditure reductions are expected to increase from $40,000 to $80,000. The increase is due to the benefits realized from three initiatives including: the fleet second shift; the facilities purchasing cards mentioned above; and the streamlining of the purchase order processes, also described on Exhibit 4, Tab 3, and Schedule 4. The fleet second shift and the availability of p-cards for Facilities accounts for $40,000 of this increase.

In 2015, operating expenditure reductions are forecast to increase by $20,000. The increase is due to additional reduction of purchase orders from the implementation of purchasing cards for facilities purchases and streamlining purchasing processes mentioned above.

From 2016 to 2019, the operating expenditure reductions from the three initiatives mentioned above are expected to be sustained.

Productivity Improvements/Capacity

In 2012, productivity improvement/capacity benefit of $20,000 was achieved due to reduction and duration of departmental meetings described on Exhibit 4, Tab 3, and Schedule 4. This initiative reduced the quantity and duration of department meetings by 50% or 344 hours between Supply Chain Management employees.

In 2013, productivity improvement/capacity benefit of $50,000 was achieved due to two initiatives described on Exhibit 4, Tab 3, and Schedule 4: reduction and duration of departmental meetings; and reduction of facilities maintainers travel time to support Horizon Utilities buildings. The productivity improvement/capacity benefits of $50,000 were generated by the reduction of 860 hours from the two initiatives described above.

In 2014, productivity improvement/capacity benefits are expected to increase from $50,000 to $90,000. The increase is due to the benefits realized from four initiatives: the reduction and duration of departmental meetings, reduction of facilities maintainers travel time to support Horizon Utilities buildings, the use of current bar coding solution for fleet inventory and streamlining of the purchase order processes, also described on Exhibit 4, Tab 3, and Schedule 4.

In 2015, productivity improvement/capacity benefits from 2014 are forecast to be sustained.

In 2016, productivity improvement/capacity benefits are forecast to increase by $10,000. The increase is due to additional reduction of purchase orders from the implementation of purchasing cards for facilities purchases and streamlining purchasing processes mentioned above.

Productivity improvement/capacity achievements from 2016 are expected to be sustained in 2017 and increased by $20,000 in 2018 and another $20,000 in 2019 due to additional reduction of purchase orders from the implementation of purchasing cards for facilities purchases and streamlining purchasing processes mentioned above.

Finance

For ease of reference, the productivity achievements in Finance shown in Table 4-43 are shown below.

Table 5: Productivity Achievements in Finance

Finance	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prod.Impr/Cap	$ -	$ -	$ 50,000	$ 240,000	$ 340,000	$ 340,000	$ 340,000	$ 340,000	$ 340,000

Please refer to BOMA-8_Attch 5_Finance for more details on the calculations.

Productivity Improvements/Capacity

In 2013, the productivity achievement of $50,000 was due to two initiatives described on pages 38-39 of Exhibit 4, Tab 3, Schedule 4: Activity-Based Costing / Business Intelligence (“ABC/BI”); and Electronic Funds Transfer (“EFT”). ABC/BI contributes $20,000 towards this achievement based on the number of queries performed, the average hourly burdened rate of management staff and average time savings of two hours per query, compared to the time required to extract the same data prior to the system’s implementation. The EFT implementation contributes $30,000 towards the productivity achievement based on the number of EFT transactions which replaced printed cheques, and associated staff time savings associated with transaction processing and review.

In 2014, productivity is expected to increase by $190,000 to $240,000. The increase is due to the benefits realized from three initiatives: ABC/BI and EFT mentioned above; and the Financial

Planning Solution also described on pages 38-39 of Exhibit 4, Tab 3, Schedule 4. The Financial Planning Solution, first implemented in 2013, accounts for $100,000 of this increase due to a reduction in management staff time required to prepare annual budgets and quarterly forecasts, as well as reduced time spent on monthly variance analysis as a result of improved budgeting.

Approximately $80,000 in incremental productivity is due to an increase in the volume of queries enabled by the ABC/BI system, while $10,000 in incremental productivity is due to an increase in the number of EFT transactions.

In 2015, productivity achievements are forecast to increase by $100,000. The increase is due to a new business initiative to improve Horizon Utilities' use of Activity-Based Costing as described on pages 28-29 of Exhibit 4, Tab 2, Schedule 2. This estimate is based on achieving benefits equivalent to 1% of annual OM&A of approximately $10,000,000 to support key processes within regulated electricity distribution operations.

The benefits to be achieved by Finance in 2015 are expected to persist throughout the Custom IR period.

b) Horizon Utilities does not foresee any degradation of the Horizon Utilities "brand" due to outsourcing of a portion of the Call Centre customer calls. Horizon Utilities views the overflow outsource service provider as an extension of the existing Call Centre. Robust training of the service provider agents is provided by Horizon Utilities' staff to ensure consistency of customer service delivery. The service provider will be held to the same standards and metrics as Horizon Utilities' staff. This includes the applicable Service Quality Indicators as provided in Exhibit 1, Tab 2, Schedule 2, Page 13, including Call Quality measurements.

As described in Exhibit 4, Tab 3, Schedule 2 starting on Page 12 and its response to 1-Staff-7, part d), Horizon Utilities anticipates a number of customer benefits as a result of outsourced overflow Call Centre services. The primary benefits to customers will be increased accessibility to an agent and extended hours of service without incremental expenditures as demonstrated in the cost-benefit table below.

Table 6: Cost Benefit Analysis

Horizon Utilities annual expenditures of in-house Call Centre services as compared to Outsource Provider		
	Internal Expense	**Outsource provider**
5 FTE agents during regular business hours	$434,707	$291,200
3 agents for extended hours, 2 hours / day		$49,920
Total	**$434,707**	**$341,120**

Horizon Utilities performed its initial cost-benefit analysis by reviewing the equivalency of 5 internal agents transitioning to the outsource service provider, the ability to provide expanded hours of service of two hours per day Monday through Friday, and expenditures related to after-hours Call Centre services in the event of power outages or other emergencies.

The table above details the cost benefits of transitioning to an outsourced overflow service at the 2014 hourly burdened rates for internal staff and 2014 rates and related services charges as provided by the outside service provider.

Call Centre staff also provide after-hours call response during large power outages or other emergency events, as required. The expenditure related to providing 200 after-hours support internally during emergencies is $19,108, based on utilizing Horizon Utilities staff as compared to $11,350 utilizing the outsource service provider.

Based upon the information provided by the outside service provider, and pending the completion of all training components to conform to Horizon Utilities standards, Horizon Utilities anticipates the ability to provide service enhancements to customers through expanded hours of service and scheduling of additional agents during peak periods while achieving cost containment of OM&A in the Call Centre.

Horizon Utilities plans to transition services to the overflow service provider as attrition occurs in the Call Centre. The Call Centre's anticipated headcount reductions due to staff retirements and normal turnover are provided in Exhibit 4, Tab 3, Schedule 2, Page 6.

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BOMA-8_Attch_1_Construction and Maintenance

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Construction & Maintenance (C&M)

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operating Expenditure Reductions									
Overtime Reduction	-	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Staff Reductions (Outsourcing)	-	-	-	200,000	300,000	400,000	400,000	400,000	400,000
Total C&M Operating Expenditure Reductions	**$ -**	**$100,000**	**$ 100,000**	**$ 300,000**	**$ 400,000**	**$ 500,000**	**$ 500,000**	**$ 500,000**	**$ 500,000**
Productivity and Capacity Improvements									
Reduction in Downtime (Trouble Crew)	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Training Time per Employee		200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Reduction in Average Absenteeism	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Yard Time Savings	-	-	670,000	670,000	670,000	670,000	670,000	670,000	670,000
Time Allocated to Meetings	-	-	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Time Allocated to Training	-	-	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Maintenance & Service Work to Trouble Crew	-	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Reduction in Average Absenteeism	-	-	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Total C&M Productivity and Capacity Improvements	**$ -**	**$600,000**	**$1,720,000**	**$1,720,000**	**$1,720,000**	**$1,720,000**	**$1,720,000**	**$1,720,000**	**$1,720,000**

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BOMA-8_Attch_2_IST

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Information Systems & Technology (IST)

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operating Expenditure Reductions									
ERP Upgrade Phase 1									
Elimination of 1 FTE	-	-	36,000	108,000	108,000	108,000	108,000	108,000	108,000
In-house Tech Support	-	-	29,267	77,800	77,800	77,800	77,800	77,800	77,800
Elimination of Server Hardware Maintenance	-	-	25,833	77,500	77,500	77,500	77,500	77,500	77,500
Depreciation Expense Reduction	-	-	50,000	150,000	150,000	150,000	150,000	150,000	150,000
IFS Managed Cloud Services	-	-	(81,100)	(243,300)	(243,300)	(243,300)	(243,300)	(243,300)	(243,300)
ERP Upgrade Phase 2									
Removal of Custom Modifications	-	-	-	30,000	50,000	50,000	50,000	50,000	50,000
Total IST Operating Expenditure Reductions	**$ -**	**$ -**	**$ 60,000**	**$ 200,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**
Productivity and Capacity Improvements									
ERP Upgrade Phase 2	-	-	-	30,000	40,000	40,000	40,000	40,000	40,000
ERP Upgrade Phase 3									
Mobile Administration	-	-	-	3,000	6,000	6,000	6,000	6,000	6,000
Single Sign On - User	-	-	-	28,656	68,775	68,775	68,775	68,775	68,775
Single Sign On - Password Reset	-	-	-	719	1,725	1,725	1,725	1,725	1,725
Mobile Desktop (VDI)	-	-	-	67,518	202,555	202,555	202,555	202,555	202,555
Business Analytics	-	-	-	10,398	31,195	31,195	31,195	31,195	31,195
Accounts Payable-Cash Discounts	-	-	-	-	11,000	11,000	11,000	11,000	11,000
Purchase Orders-Buyer	-	-	-	-	39,375	39,375	39,375	39,375	39,375
Purchase Orders-Contract Admin.	-	-	-	-	34,020	34,020	34,020	34,020	34,020
Accounts Payable-3-way Match	-	-	-	-	33,750	33,750	33,750	33,750	33,750
Mobile Touch Apps	-	-	-	-	54,900	54,900	54,900	54,900	54,900
Std. Labour Rates and ABC Review	-	-	-	-	153,300	153,300	153,300	153,300	153,300
Eco-FootPrint	-	-	-	-	34,350	34,350	34,350	34,350	34,350
OEB Trial Balance	-	-	-	-	32,500	32,500	32,500	32,500	32,500
IFS Upgrade 2018	-	-	-	-	-	-	-	30,000	130,000
Enterprise Unified Communications					280,000	280,000	280,000	280,000	280,000
Total IST Productivity and Capacity Improvements	**$ -**	**$ -**	**$ -**	**$ 140,000**	**$1,020,000**	**$1,020,000**	**$1,020,000**	**$1,050,000**	**$1,150,000**

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BOMA-8_Attch_3_Customer Service

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Customer Service (CS)

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operating Expenditure Reductions									
E-Mobile	25,304	209,332	400,262	600,000	600,000	600,000	600,000	600,000	600,000
Outsourcing	-	-	-	-	-	-	-	-	-
MV90 Operator			60,391	70,000	60,000	60,000	60,000	60,000	60,000
Call Centre Overflow						10,000	20,000	30,000	40,000
Miscellaneous									
Meter Reading Expenditure Reduction		93,236	144,928	140,000	150,000	150,000	150,000	150,000	150,000
E-Billing for Multi-account Customer		3,216	10,618	10,000	15,000	17,000	19,000	19,000	19,000
Overtime Reduction		55,863	32,895	20,000	25,000	20,000	20,000	20,000	20,000
Elimination of one General Clerk FTE			25,932	60,000	65,000	65,000	65,000	65,000	65,000
Payment pickups from Drop-off Locations			4,080	4,000	4,000	4,000	4,000	4,000	4,000
Courier Service Elimination			5,355	9,000	9,000	9,000	9,000	9,000	9,000
Increase in e-billing services			5,970	7,000	57,000	80,000	98,000	118,000	138,000
Other		24,563	12,000						
Total CS Operating Expenditure Reductions	**$25,304**	**$386,210**	**$ 702,431**	**$ 920,000**	**$ 985,000**	**$1,015,000**	**$1,045,000**	**$1,075,000**	**$1,105,000**
Productivity and Capacity Improvements									
E-Mobile	51,818	296,263	695,704	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Miscellaneous Initiatives		119,602	136,255	150,000	150,000	170,000	190,000	200,000	210,000
Total CS Productivity and Capacity Improvements	**$50,000**	**$420,000**	**$ 830,000**	**$1,300,000**	**$1,300,000**	**$1,320,000**	**$1,340,000**	**$1,350,000**	**$1,360,000**

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BOMA-8_Attch_4_Supply Chain

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Supply Chain Management (SCM)

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operating Expenditure Reductions									
Fleet Second Shift	-	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
P-Cards for Facilities Purchases	-	20,000	30,000	40,000	40,000	40,000	40,000	40,000	50,000
Streamline Purchasing Process	-	-	-	30,000	40,000	40,000	40,000	50,000	50,000
Total SCM Operating Expenditure Reductions	**$ -**	**$ 40,000**	**$ 50,000**	**$ 90,000**	**$ 100,000**	**$ 100,000**	**$ 100,000**	**$ 110,000**	**$ 120,000**
Productivity and Capacity Improvements									
Reduction of SCM Department Meetings	-	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Facilities Employee Travel Time Reduction	-	-	20,000						
P-Cards for Facilities Purchases	-	-	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Streamline Purchasing Process	-	-		20,000	20,000	30,000	30,000	40,000	40,000
Warehouse Workflow Rotation Schedule	-	-		10,000	10,000	10,000	10,000	20,000	20,000
Material Picking Process	-	-		20,000	20,000	20,000	20,000	20,000	40,000
Bar Coding for Vehicle Parts Inventory	-	-		10,000	10,000	10,000	10,000	10,000	10,000
Total SCM Productivity and Capacity Improvements	**$ -**	**$ 20,000**	**$ 50,000**	**$ 90,000**	**$ 90,000**	**$ 100,000**	**$ 100,000**	**$ 120,000**	**$ 140,000**

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BOMA-8_Attch_5_Finance

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Finance

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operating Expenditure Reductions									
Total Finance Operating Expenditure Reductions	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Productivity and Capacity Improvements									
Activity-Based Costing/Business Intelligence system:									
Reduction in time query time			20,000	100,000	100,000	100,000	100,000	100,000	100,000
Key Business Process Change Savings					100,000	100,000	100,000	100,000	100,000
Financial Planning Solution :									
Reduction in Budget and Forecast Preparation				43,600	43,600	43,600	43,600	43,600	43,600
Reduction in Monthly Variance Preparation				56,400	56,400	56,400	56,400	56,400	56,400
Electronic Funds Transfer (“EFT”) :									
Cheque Preparation			14,215	17,773	17,773	17,773	17,773	17,773	17,773
Transaction Reviews			14,376	17,973	17,973	17,973	17,973	17,973	17,973
Additional Clerical Savings			305	305	305	305	305	305	305
Material Savings			4,360	5,674	5,674	5,674	5,674	5,674	5,674
Total Finance Productivity and Capacity Improvements	**$ -**	**$ -**	**$ 50,000**	**$ 240,000**	**$ 340,000**	**$ 340,000**	**$ 340,000**	**$ 340,000**	**$ 340,000**

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BOMA-9

Reference:

Annual Customer Satisfaction Survey

(a) p8: How are "secure customers" and "at risk customers" defined?

(b) p12: Are the "competitors" other utilities in Ontario or are they all the other businesses in Ontario that the contractor has surveyed.

(c) p35: To what do you attribute the 73% rating on "provides good value for money", which is below the company's ratings on other criteria.

Response:

a. UtilityPulse defines the Customer Loyalty classifications on Page 61 of the Horizon Utilities' Customer Satisfaction Survey as provided in Exhibit 4, Tab 3, Appendix 4-1.

   "Secure" customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

   "At risk" customers are "very dissatisfied" with their electric utility, "definitely" would switch if provided with options, and "definitely" would not recommend it.

b. The UtilityPulse survey does not reference "competitors". The methodology for the development of the Ontario and National benchmark data is provided on Page 110 of the Customer Satisfaction Survey.

   The Ontario and National benchmarks were developed from telephone interviews with residential and small commercial utility customers. The National and Ontario comparators do not include other types of industry or businesses in this survey.

c. Horizon Utilities' 2013 survey result of 73% rating on "provides good value for the money" as provided on Page 35 of the Customer Satisfaction Survey compares favourably against the Ontario benchmarks of 68%.

   Horizon Utilities attributes the lower rating as compared to the other service quality attributes to industry challenges articulating the value proposition of electricity to customers. In addition, customers may not necessarily separate the Horizon Utilities' portion of their bill from the total invoice when providing feedback on the “providing good value for the money” attribute.

Horizon Utilities attributes the lower rating as compared to the ratings for other criteria to challenges in articulating the value proposition of electricity to customers. In addition, customers may not necessarily separate Horizon Utilities’ portion of their bill from the total invoice when providing feedback on the notion of “providing good value for the money”.

BOMA-10

Reference:

Revenue and Rates

(a) 2015 revenue relative to 2014 revenue increased 11% for the residential class but 20% for general service under 50kV class and 26% for the general service over 50kV. Please explain fully the cost allocation changes, rate design, or revenue to cost ratio changes or other factors that account for these different rates of class revenue growth in the first test year. Please discuss fully.

(b) p(iii) Please confirm that the Hydro One Transformer Station listed, and others that step down voltages are owned by HONI which is responsible for monitoring, maintaining, refurbishing and expending these stations. Where the station listed are approaching limited time ratings (please define) HONI that will deal with the issues in a timely fashion. Please provide details, including the amount of liaisons/communications Horizon has with HONI.

(c) p(iii) Please confirm that the projected growth rate in energy (levels) for the IRM period is 25% for the utility as a whole. What are the forecast growth rates for each customer class.

Response:

a) Horizon Utilities would like to begin by clarifying the % increases in distribution revenue over 2014. Table 1 provides the percentage increase in proposed 2015 Distribution Revenues over 2015 Revenues at existing 2014 rates.

Table 1: 2015 Proposed Distribution Revenue Compared To 2015 Distribution Revenue at Existing Rates

Class	Dist. Rev. Excluding Transformer at 2014 Rates	Proposed Dist. Rev. Base Revenue	% Increase in Dist. Rev
Residential	63,270,290	69,461,355	9.79%
GS < 50 kW	12,383,472	15,412,682	24.46%
GS >50 to 4999 kW	17,191,673	21,400,734	24.48%
Standby	745,248	739,292	(0.80%)
Large Use (1)	2,827,619	2,157,451	(23.70%)
Large Use (2)	3,721,203	480,086	(87.10%)
Sentinel Lights	37,542	46,725	24.46%
Street Lighting	2,202,026	2,740,679	24.46%
Unmetered and Scattered	509,223	517,021	1.53%
	102,888,297	**112,956,026**	9.79%

Horizon Utilities offers the following in regard to changes to Cost Allocation and Rate Design.

Cost Allocation

Horizon Utilities has used the Board's Cost Allocation model to determine the costs to be allocated to each rate class. As provided in Exhibit 7, Tab 1, Schedule 1:

"Horizon Utilities engaged Elenchus Research Associates Inc. (Elenchus) to undertake a review of Horizon Utilities' 2011 CA Model that included a detailed examination of the actual facilities included in the accounts that serve as inputs to the model to determine whether there could be refinements that would better reflect the principle of cost causality in allocating costs to customers."

The final report as issued by Elenchus was filed as Appendix 7-1 to Exhibit 7.

Horizon Utilities has provided a full description of all updates to the Cost Allocation model in Exhibit 7, Tab 1, Schedule 1. The list of updates discussed in Exhibit 7 is as follows:

- Introduction of the LU (2) Customer Class;
- Revised Allocation of Sub-Accounts;
- Updated Street Light Device/Connection ratio;
- Demand Allocators PNCP1exSU, PNCP4exSU, PNCP12exSU; and
- Updated Weighting Factors.

Rate Design

Horizon Utilities has provided a breakdown of the distribution revenue percentage increase due to the status quo increase, and due to the adjustment of Revenue to Cost ratios in its response to Interrogatory 7-EP-49 (a) Table 1. The 9.79% increase that is applied to all rate classes is the same percentage applied within the Board's Cost Allocation model and represents the uniform percentage increase to revenues at existing rates required for the utility to recover its forecast revenue requirement. The remaining increase/decrease to distribution rates is the result of the rebalancing of revenue-to-cost ratios to within the Board's approved ranges.

b) Horizon Utilities confirms that the Hydro One Transformer stations listed under section 2.2.2 of the DSP (Exhibit 2, Tab 6, Appendix 2-4, pages 69-98) are owned and operated by Hydro One and they are responsible for monitoring, maintaining, refurbishing and expending with the exception of metering instrument transformers.

The "Limited Time Rating" or "10 Day LTR" are provided by Hydro One. The LTR is defined as the maximum available capacity for which one transformer can remain in service prior to damage. For example, the Dundas TS T3/T4 transformer pair has a 10 Day LTR of 96MVA. This means if the T3 or T4 transformer failed, the remaining transformer could continue to provide up to 96MVA of load for 10 days until significant damage would occur.

Horizon Utilities meets with Hydro One quarterly (at a minimum) to review planning issues for the entire distribution system. Additional meetings or conference calls are held as required to discuss specific issues. Through Regional Planning, Horizon Utilities has another avenue for discussion with Hydro One. Horizon Utilities also meets with Hydro One on system performance issues and attends both the bi-annual customer conference on outage planning and annual large user's conference.

c) Horizon Utilities' projected growth rate in energy levels is not 25%. Horizon Utilities projected total sales are in fact quite stable over the 2015 – 2019 term as shown in Exhibit 3, Tab 2, Schedule 1. Table 2 provides the energy growth broken down by rate class.

Table 2: Energy By Rate Class

Monthly Fcst Aggregate	2014	2015	2016	2017	2018	2019	% Growth over 2014	Average Annual Growth Rate
Residential-kWh	1,622,497,190	1,617,715,605	1,615,569,770	1,608,117,860	1,604,991,612	1,600,739,130	-1.34%	-0.27%
GS<50-kWh	592,239,398	586,002,830	585,648,636	583,142,939	581,558,617	579,899,038	-2.08%	-0.42%
GS>50-kWh	1,852,884,169	1,857,864,416	1,852,830,462	1,841,172,846	1,831,925,238	1,822,597,172	-1.63%	-0.33%
USL-kWh	11,685,761	11,397,660	11,174,331	10,951,001	10,727,671	10,504,342	-10.11%	-2.02%
Sentinel-kWh	462,083	437,397	418,980	400,564	382,147	363,731	-21.28%	-4.26%
Streetlight-kWh	39,721,302	39,694,810	39,602,538	39,651,553	39,629,670	39,610,413	-0.28%	-0.06%
LU (2)-kWh	325,479,566	329,305,006	335,708,389	342,466,388	348,682,806	354,940,487	9.05%	1.81%
LU (1) - kWh	263,395,258	269,877,849	275,125,662	280,664,097	285,758,686	290,887,091	10.44%	2.09%
Total-Sales	**4,708,364,729**	**4,712,295,573**	**4,716,078,768**	**4,706,567,248**	**4,703,656,447**	**4,699,541,403**	**-0.19%**	

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BOMA-11

Reference:

Ex4 - Operating Costs

(a) **Ex4, T1, S1, p4, Table 4-2: Please confirm that the cumulative IRM period cash flow from the application over what Horizon would receive in a 1- X IRM is found in columns 2015 and 2016 in the last line of the table and is approximately $24 million. If not, please explain what the cumulative differential is over the 5 year period 2015-2019.**

(b)(i) **Please provide the Table 2 comparison using the Board approved productivity of72% for the 2012 and 2013 year rather than 0.**

(b)(ii) **Please justify applying 0% productivity retroactively to 2012 and 2013.**

Response:

a) Horizon Utilities confirms that the cumulative differential from 2015-2019 is $24,900,000; corresponding to the sum of the last line of Table 4-2 from the 2015 to the 2019 columns.

b)i) Please refer to the response to 1-EP-3 b) and, more specifically, the corresponding 1-EP-3 Attch 4.

b)ii) Please refer to interrogatories 1-SIA-7 a) and b) and the corresponding responses.

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BOMA-12

Reference:

Operating Costs

Preamble:

The Company's OMA cost per customer has risen from $216.50 in 2011 (Board Approval as converted by MIFRS), to $249.85 in 2014, to $257.41 (2015 test year) to $275.56 (2019 test year), an increase of 59.00 over a 8 year period on an average of $7.5/year about 3.5 per year for 8 years. That seems excessive.

Please explain the 2015 OMA of 62.6 million compared to the 2012 OMA of 51.5, an annual increase of 7%, which is even more excessive.

Response:

Horizon Utilities identified small errors in the customer counts in 2011 to 2013 Actual. The revised Table 4-20, is included below. These errors do not affect the OM&A per customer numbers quoted above for 2014 to 2019.

Table 4-20.1 OM&A per Customer and per FTE restated (with correction to Number of Customers)

	Last Rebasing Year -2011- Board Approved	Last Rebasing Year - 2011- Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Number of Customers	237,031	237,305	238,488	240,114	241,692	243,319	245,123	247,036	249,021	250,909
Total Recoverable OM&A from Appendix 2-JB	$ 42,136,201	$ 41,644,654	$ 51,478,365	$ 54,516,506	$ 60,387,369	$ 62,632,679	$ 64,394,131	$ 66,255,827	$ 67,708,658	$ 69,140,489
OM&A cost per customer	$ 177.77	$ 175.49	$ 215.85	$ 227.04	$ 249.85	$ 257.41	$ 262.70	$ 268.20	$ 271.90	$ 275.56
Number of FTEs	349	328	333	335	355	348	345	344	344	344
Customers/FTEs	679	724	717	717	682	700	711	718	723	729
OM&A Cost per FTE	$ 120,699.52	$ 127,058.38	$ 154,729.08	$ 162,735.84	$ 170,340.38	$ 180,103.17	$ 186,649.65	$ 192,458.68	$ 196,678.84	$ 200,838.00

The table below summarizes the variance between 2015 forecast and 2012 Actual by main cost drivers.

Table 1: Main Cost Drivers 2015 vs 2012

	2012 Actual MIFRS	2015 Test Year MIFRS	2015 v 2012 Variance	*2015 v 2012 CAGR*
Salaries, Wages and Benefits	$ 27,873,703	$ 33,445,459	$ 5,571,756	*6.3%*
Non-Labour Expenses	$ 19,532,010	$ 23,201,129	$ 3,669,120	*5.9%*
New Business Requirements	$ 400,733	$ 1,672,668	$ 1,271,934	*61.0%*
Net Management Fees	$ 6,133,665	$ 6,927,618	$ 793,953	*4.1%*
Distributed Costs	$ (2,461,746)	$ (2,614,195)	$ (152,449)	*2.0%*
Total	**$ 51,478,365**	**$ 62,632,679**	**$ 11,154,314**	*6.8%*

Salaries, Wages and Benefits

Salaries, wages, and benefits increases are the main contributor to the OM&A cost variance in the 2015 year over 2012 Actual, representing $5,571,756 of the total OM&A increase of $11,154,314 over the period. The increase in salaries, wages, and benefits is driven by several factors: salary and wage increases resulting from inflation and merit increases for employees currently not at full job rate; FTE growth; and pension and benefits increases (both in contribution rates and related to wage growth).

The impact on salaries, wages, and benefits due to increases in FTE and salaries, wages, and benefits inflation is a total increase of $5,805,799 between 2012 Actual and 2015 forecast, of which $5,571,756 is allocated to OM&A.

The primary driver for the increase is annual inflationary adjustments in salaries and wages which represent $2,781,105 of the $5,805,799 increase. Please refer to Exhibit 4, Tab 2, Schedule 2 for historical wage inflation increases to 2013, and for the rates of the prevailing Horizon Utilities' Collective Agreement with the IBEW for union employees. Exhibit 4, Tab 4, Schedule 2 explains in more detail Horizon Utilities compensation program and how inflationary adjustments and merit increases are determined.

The second largest driver for the increase in salaries, wages, and benefits between 2012 Actual and the 2015 year is the growth of 14.6 FTE (excluding temporary resources for New Business

Requirements (“NBR”)), representing $1,178,621 of the $5,805,799 increase. Detailed explanations for the additional FTE are included in Exhibit 4, Tab 4, Schedule 2. The 2015 forecast FTE figure assumes that all positions in 2015 are fully staffed and that new positions are filled as of the budgeted hire date.

Benefits comprise $1,675,392 of the $5,805,799 increase in salaries, wages and benefits; including the impact of changes in FTE. The benefits costs per employee have increased by $3,769 from $23,617 to $28,937, or at a CAGR of 4.8% from 2012 Actual to the 2015 year; driven primarily by the increase in the employer contribution rates for OMERS (Table 4-14 in Exhibit 4, Tab 2, Schedule 2) and higher post-employment benefits costs.

Projected post-employment benefits costs and projections used in the Application were provided to Horizon Utilities by its independent advisor and actuary, Eckler Ltd., a firm of consultants and actuaries with experience in the field of pensions and benefits. The report from Eckler Ltd. is provided in Exhibit 4, Tab 4, Appendix 4-4.1.

Non-Labour Expenses

Non-labour expenses associated with core business activities have increased $3,669,120 or a compound annual growth rate (CAGR) of 5.9% from the 2012 Actual to the 2015 year. These expenditures are necessary to sustain and improve service to Horizon Utilities’ customers including: maintaining service reliability within customers’ expectations; maintaining business continuity; managing related business risks; and safety.

There is urgency to step up OM&A in 2014 and 2015 to address the non-controllable, regulatory, and managed cost drivers that will affect Horizon Utilities in those years and thereafter. The rationale and justification for such managed growth is articulated in the Application and corresponds to themes such as: support for urgent and rising distribution renewal investment and ongoing medium-term growth in maintenance programs; delivery of customer value through information technology investments to enhance distribution system management and monitoring and timely customer access and response; and to provide functional and sustainable office and operating centre work environments.

The principal drivers that influence cost increases are (all the numbers stated below are comparisons between 2015 forecast and 2012 Actual):

Table 2: Cost Drivers

Repairs And Maintenance - Equipment	$	520,415
Software and Hardware License And Maintenance	$	388,070
Janitorial, Landscaping, HVAC and Service Agreement	$	331,711
Tree Trimming	$	256,422
Property tax	$	250,519
Internet Services	$	222,153
Utilities	$	172,030
Outside Service Provider	$	145,683
Travel and accommodation	$	138,425
Insurance - Property	$	129,400
Insurance - Property	$	100,968

The justification and explanation for each of the cost variance above is provided in Exhibit 4, Tab 2, Schedule 2.

New Business Requirements

New Business Requirements (NBR) expenses associated with projects incremental to recurring annual costs incurred in 2011 represent $1,271,934 of the total OM&A increase of $11,154,314 over the period 2012 to 2015*.* These projects are undertaken to: (i) manage risks and ensure sustainability of critical business operations; (ii) comply with legislated or regulatory requirements; and (iii) to provide future cost savings or enable cost avoidance which benefit ratepayers over the long term.

Key initiatives that will be underway in 2015 that were not present or had just commenced in 2012 are (all the numbers stated below are comparisons between 2015 year and 2012 Actual):

Table 3: New Business Requirements

New Business Requirements	2015 v 2012
Sustainability/ Risk Mitigation	
GIS/OMS	$ 684,177
Collective Bargaining	$ 100,000
Regulatory/ Compliance	
Green Energy Act	$ 123,147
Cost of Service Application 2015	$ 551,941
Return on Investment	
Activity Based Costing	$ 100,000

An explanation of these initiatives is provided in Exhibit 4, Tab 2, Schedule 2.

Management Fees

Net Management Fees have increased by $793,953 representing a CAGR of 4.1% from the 2012 Actual to the 2015 year. As explained in Exhibit 4, Tab 2, Schedule 2 management fees relate to costs charged by Customer Care to EDO for customer care services and costs charged by HHI for corporate communications and stakeholder/ public relations, partially offset by amounts recovered by EDO for providing back office functions to affiliate entities.

The increase in costs between 2012 and 2015 is due to refinement in allocations from 2014 onwards following a recent Transfer Pricing Study undertaken. This study is included in Appendix 4-6.1 of Exhibit 4.

BOMA-13

Reference:

Intemperate Services and Corporate Cost Allocation

Preamble:

The organization chart for which shows the ownership of Horizon Utilities ("HU") and its affiliated companies is found at Ex1, T9, Sch2, p3. Horizon also states (Ex4, T4, Sch 3, pi) that HU has 4 divisions, Electricity Distribution Operations ("EDO"), Customer-Care ("CC"), Conservation and Demand Management ("CDM") and Solar Solutions General Partnership ("SSGP"). BOMA assumes that CC and CDM are divisions of HU. The evidence states "the revenues, activities and financial accounts of CC and CDM are treated separately from EDO for the purposes of this application".

With respect to the CDM and CC divisions of HU, services are provided by EDO to the CDM and CC divisions and vice versa.

(a) Are the non-EDO divisions managed separately from EDO. Do they have their own management teams. Do they report to the President of EDO, or are they separately managed entities. If so, what is their purpose. Why are they accounted for separately, "for the application".

(i) When was the decision made to established these separate divisions and entities and for what reasons.

(ii) Please provide copies of the 2009 and 2014 Service Agreements between Horizon, its affiliate and separate divisions.

(iii) Please provide a copy of the Horizon's current Agreement with the OPA for CDM.

(iv) Please provide the number of FTES in the CDM division, or in EDO but doing CDM work.

Response:

a) There are four divisions within Horizon Utilities which are managed separately from one another: Electricity Distribution Operations ("EDO"), Customer Care ("CC"), Conservation and Demand Management ("CDM") and Solar Sunbelt General Partnership ("SSGP"). CC and CDM report to the Vice President, Customer Services who also oversees an EDO department (i.e., Customer Connections). SSGP is managed by the Vice President, Horizon Energy Solutions Inc.

The purpose of these divisions is to distinguish rate-regulated electricity distribution operations (EDO) from other business activities of Horizon Utilities. In this application, Horizon Utilities' revenue requirement considers only those costs incurred by EDO and not costs incurred in other divisions, except to the extent such costs are attributable to EDO in which case the management fee amount (charged to EDO by CC) has been included in EDO's Operations, Maintenance and Administration expenses.

(i) The decision to establish separate divisions was initially made in 2001 at the time the first service agreement was established for the Customer Care function to perform water billing services for the City of Hamilton. The CDM and SSGP divisions were subsequently established at the time that Horizon Utilities entered these businesses. The reasons for establishing these divisions are explained in part (a) above.

(ii) Horizon Utilities has provided the 2009 and 2014 Service Agreements between Horizon Utilities and its affiliates in Appendix 4-6.3 (2009) and Appendix 4-6.2 (2014). There are no Service Agreements between divisions of Horizon Utilities as these services are provided within the same legal entity, however the Transfer Pricing Study at Appendix 4-6.1 provides the details of the management fee calculations that ensure a fair allocation of costs between EDO and other divisions of Horizon Utilities.

(iii) Please find included as BOMA-13-Attch 1_OPA Agreement the current agreement between Horizon Utilities and the OPA for CDM.

(iv) There are 17.8 FTEs in the CDM division for the first five months of 2014. There are no CDM employees in the EDO division.

BOMA-13_Attch 1_OPA Agreement

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MASTER CDM PROGRAM AGREEMENT

BETWEEN

ONTARIO POWER AUTHORITY

- and -

LDC
(as defined herein)

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MASTER CDM PROGRAM AGREEMENT

This Master CDM Program Agreement is made as of the 1st day of January, 2011 (the "**Effective Date**").

BETWEEN:

ONTARIO POWER AUTHORITY, a corporation incorporated pursuant to the laws of the Province of Ontario,

(the "**OPA**")

- and -

THE LOCAL DISTRIBUTION COMPANY THAT BECOMES LEGALLY BOUND HEREBY PURSUANT TO THE ELECTRONIC CONTRACTING AND REGISTRATION PROCESS SET OUT ON THE OPA WEBSITE, a corporation incorporated pursuant to the laws of the Province of Ontario,

(the "**LDC**")

(each of the OPA and the LDC may be referred to as a "**Party**" and, collectively, the "**Parties**")

WHEREAS:

1. The OPA was established by the *Electricity Restructuring Act, 2004* (Ontario) for the purpose, among others, of engaging in activities that promote electricity conservation and the efficient use of electricity.

2. The LDC is the Local Distribution Company for its service area.

3. The OPA received a directive dated April 23, 2010 from the Minister of Energy and Infrastructure (the "**Directive**") to, among other things, design, deliver and fund province-wide CDM programs to be made available for participation by Local Distribution Companies in accordance with the criteria set out in the Directive.

4. The OPA received a directive dated July 5, 2010 from the Minister of Energy and Infrastructure (the "**Low Income Directive**") to, among other things, design, implement and fund the electricity CDM program for low-income residential consumers as part of the province-wide CDM programs in accordance with the criteria set out in the Low Income Directive.

5. The OPA received a directive dated December 21, 2012 from the Minister of Energy ("**Extension Directive**") to, among other things, fund the province-wide CDM programs for an additional one-year period from January 1, 2015 to December 31, 2015, in accordance with the criteria set out in the Directive.

6. In collaboration with the Local Distribution Companies, the OPA has designed the OPA-Contracted Province-Wide CDM Programs to assist the Local Distribution Companies in meeting their OEB-approved CDM targets. The OPA, in offering the OPA-Contracted Province-Wide CDM Programs, is required to meet its province-wide targets.

7. The LDC is required to meet its OEB-approved CDM targets and has Registered to participate in the Registered CDM Programs and the Registered Initiatives. During the Term, the LDC may choose to participate in other CDM Programs and Initiatives (including Additional Initiatives).

8. The OPA-Contracted Province-Wide CDM Programs consist of four programs that each target a different customer sector: Industrial, Commercial and Institutional, Residential and Low Income. Each CDM Program consists of several Initiatives.

9. Funding for the CDM Programs is recovered from electricity consumers in the Province of Ontario and, as such, is required to be delivered on a cost-effective basis.

10. The OPA and the LDC share a common goal and each acknowledges that cooperation with the intention of achieving such goal will be mutually beneficial. The LDC wishes to implement and deliver to its customers in its service area each of the Registered CDM Programs and each of the Registered Initiatives, and the OPA wishes to make available and fund each of the Registered CDM Programs and each of the Registered Initiatives, on a collaborative and cost-effective basis.

11. The LDC has strong relationships with its customers and, pursuant to the Directive and as and where specified in the Initiative Schedules, will play a primary role in delivering the Registered Initiatives to electricity consumers. The electricity consumers in the LDC's service area are electricity distribution customers of the LDC.

12. The rights and obligations of the OPA and the LDC in respect of each Initiative, in addition to those set out in the body of this Master Agreement, are specified in the Initiative Schedules attached to this Master Agreement, as this Master Agreement may be amended from time to time in accordance with the terms and conditions herein.

13. The LDC entered into this Master Agreement with the OPA electronically pursuant to the version made available by the OPA on January 27, 2011.

14. The OPA and the LDC restated this Master Agreement as version 2, effective as of July 15, 2012.

15. The OPA and the LDC amended and restated this Master Agreement as version 3, effective as of December 4, 2012.

16. The OPA and the LDC amended and restated this Master Agreement as version 4, effective as of June 10, 2013.

17. The OPA and the LDC now wish to amend and restate this Master Agreement as version 5, effective as of February 5, 2014.

NOW THEREFORE FOR VALUABLE CONSIDERATION, the receipt and sufficiency of which are acknowledged by the Parties, the Parties agree as follows:

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions

In addition to the terms defined elsewhere in this Master Agreement, capitalized terms used in this Master Agreement will have the meanings ascribed to them in Schedule A-1.

1.2 Currency

Unless otherwise indicated, all dollar amounts referred to in this Master Agreement are expressed in Canadian funds.

1.3 Headings

The insertion of headings and a table of contents is for convenience of reference only and will not affect the interpretation of this Master Agreement. The terms “hereof”, “hereunder”, and similar expressions refer to this Master Agreement and not to any particular Article, Section or other part of this Master Agreement. Unless otherwise indicated, any reference in this Master Agreement to an Article, Section, Schedule or Exhibit refers to the specified article or section of or schedule or exhibit to this Master Agreement.

1.4 Number and Gender

In this Master Agreement, words importing the singular number only will include the plural and vice versa and words importing gender will include all genders. The word “including” means “including without limitation”, and the words “include” and “includes” have a corresponding meaning.

1.5 Entire Agreement

This Master Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and supersedes all prior agreements, understandings, negotiations and discussions, whether written or oral. There are no conditions, covenants, agreements, representations, warranties or other provisions, express or implied, collateral, statutory or otherwise, relating to the subject matter hereof except as herein provided.

1.6 Governing Law and Attornment

This Master Agreement will be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. For the purpose of all legal proceedings, this Agreement will be deemed to have been made and performed in the Province of Ontario and the courts of the Province of Ontario will have exclusive jurisdiction to entertain any action arising under this Master Agreement. OPA and LDC each hereby attorns to the jurisdiction of the courts of the Province of Ontario.

1.7 Amendments

Except as otherwise expressly permitted or specified herein, this Master Agreement will not be amended or supplemented except by a written agreement that: (a) is entered into by an authorized signatory of each of the Parties which, in the case of the OPA, must be an individual at the vice president level or above; and (b) expressly states that it is intended to amend or supplement, as the case may be, this Master Agreement. For greater certainty, all Additional Initiative Schedules will, once effective in accordance with the provisions of this Master Agreement, form part of this Master Agreement and the Master Agreement will be deemed to be amended accordingly.

1.8 Waivers

No waiver of any obligation or any remedy for breach of any provision of this Master Agreement will be effective or binding unless made in writing and agreed to by an authorized signatory of the Party purporting to give the same and, unless otherwise provided, will be limited to the specific obligation or breach waived. The failure of either Party at any time to require performance by the other Party of any provision of the Master Agreement will not affect in any way the full right to require such performance at any subsequent time; nor will a waiver by either Party of a breach of any provision of this Master Agreement be taken or held to be a waiver of the provision itself.

1.9 Preparation of Agreement

Notwithstanding the fact that this Master Agreement was drafted by the OPA and its legal and other professional advisors, the Parties acknowledge and agree that any doubt or ambiguity in the meaning, application or enforceability of any term or provision of this Master Agreement will not be construed or interpreted against the OPA or in favour of the LDC when interpreting such term or provision, by virtue of such fact.

1.10 Paramountcy

The provisions of the body of this Master Agreement, any Initiative Schedule and any other Schedule are to be read and interpreted together in relation to the Registered Initiative to which such Initiative Schedule and other Schedule applies. Except as expressly provided otherwise in this Master Agreement, any inconsistency between the provisions of the body of this Master Agreement, the Initiative Schedules and any other Schedule, will be resolved by giving meaning and effect to such provisions in the following order of precedence (in descending order):

(i) the body of this Master Agreement and each Schedule that is not an Initiative Schedule; and

(ii) the Initiative Schedule applicable to a Registered Initiative.

1.11 Laws and Regulations

Unless otherwise provided, any reference in this Master Agreement to any Laws and Regulations will be a reference to the Laws and Regulations as amended, restated, re-enacted or replaced from time to time.

1.12 Schedules

The following Schedules are attached to, and are to be read with and form part of this Master Agreement:

Schedule A-1	-	Definitions
Schedule A-2	-	CDM Programs and Initiatives
Schedule A-3	-	Contract Administration
Schedule A-4	-	Change Terms
Schedule A-5	-	Funding Amounts
Schedule A-6	-	Reporting Requirements
Schedule A-7	-	Ministry Marks
Schedule B-1	-	Residential CDM Program Initiatives
Schedule B-2	-	Residential New Construction and Major Renovation Initiative
Schedule B-3	-	Residential and Small Commercial Demand Response Initiative
Schedule C-1	-	Energy Audit Initiative
Schedule C-2	-	Efficiency: Equipment Replacement Incentive Initiative
Schedule C-3	-	Direct Install Lighting and Water Heating Initiative
Schedule C-4	-	High Performance New Construction Initiative
Schedule C-5	-	[Intentionally deleted]

Schedule C-6	-	Existing Building Commissioning Incentive Initiative
Schedule D-1		Process and System Upgrades Initiative: Preliminary Engineering Study Initiative, Detailed Engineering Study Initiative and Project Incentive Initiative
Schedule D-2	-	Process and System Upgrades Initiative: Monitoring and Targeting Initiative
Schedule D-3	-	Process and System Upgrades Initiative: Energy Manager Initiative
Schedule D-4	-	Process and System Upgrades Initiative: Key Account Manager Initiative
Schedule D-6		Demand Response 3 Initiative
Schedule E-1	-	Low Income Initiative

ARTICLE 2
CDM PROGRAM ELEMENTS

2.1 Undertaking of Initiatives

Subject to the terms and conditions of this Master Agreement, during the Term, each Party will undertake and perform its respective obligations set forth in each Initiative Schedule pertaining to the Registered Initiatives. To the extent not provided in the body of this Master Agreement, the terms and conditions of each Registered Initiative will be as set forth in the Initiative Schedule relating thereto.

2.2 Duty of Care, Relationship of Parties

(a) Each of the Parties acknowledges the accuracy of the recitals to this Master Agreement to the extent that such recitals apply to it and the intentions of the Parties.

(b) Each Party agrees that its relationship with the other Party is an independent business relationship and in no way does this Master Agreement contemplate or create a relationship of employer and employee, partners, joint venturers, fiduciaries, principal and agent or any other relationship between the Parties. Without limiting the generality of the foregoing, each Party acknowledges that it is not a service provider to the other and that, subject to the terms and conditions of this Agreement, it will at all times be entitled to discharge its duties hereunder in a manner it determines in its sole discretion to be necessary or desirable in order to implement and deliver the Registered Initiatives.

2.3 Marketing

(a) The OPA will:

(i) develop a marketing and communication plan and marketing materials for Registered Initiatives in collaboration with the EDA Representative but as determined by the OPA;

(ii) communicate such marketing and communication plan to the LDC;

(iii) market the Registered Initiatives throughout Ontario using the Marketing Standards and providing appropriately balanced “air cover support” between urban and rural areas;

(iv) in connection with any changes to the Marketing Standards that could affect the LDC’s obligations hereunder, following reasonable efforts to collaborate with the EDA Representative on such changes and the timing of such changes, provide a reasonable period of advance notice to the LDC, in each case having regard to the nature of such changes;

(v) create, develop and host a website (the “**Microsite**”) that:

(A) includes content describing the Initiatives; and

(B) enables the LDC, in its discretion, to engage in customization of specifically identified portions of certain pages of the Microsite to include LDC Marks and some custom content for display to the LDC’s customers; and

(vi) include as part of its publicly available website a mechanism to link an electricity consumer to the LDC Microsite Pages or LDC Custom Microsite, as applicable.

(b) The LDC:

(i) will market each Registered Initiative to the relevant target sector, accurately describing each such Registered Initiative and accurately outlining the terms and conditions applicable to such Registered Initiatives in a manner that permits Persons to readily identify the Initiatives applicable to them;

(ii) will, in a manner it sees fit and having regard to the Initiative Schedule, develop and manage relationships with Eligible Persons for the purposes of identifying and undertaking CDM opportunities and promoting participation in the Registered Initiatives or other CDM projects to other Eligible Persons;

(iii) may, in its discretion, engage in customization of specifically identified portions of certain pages of the Microsite set aside for the LDC (the "**LDC Microsite Pages**") to include an LDC Mark and some custom content for display to the LDC's customers. If the LDC elects to engage in such customization, it will do so through the Program Management System. The LDC acknowledges that, should it not engage in such customization, then the LDC Microsite Pages will include the non-customized content provided by the OPA as part of the Microsite from time to time;

(iv) will ensure, if the LDC is engaged in customization of the LDC Microsite Pages and any other content generated by the LDC relating to the CDM Programs, that such content generated by the LDC is current, complete and accurate, and will immediately correct any such content that does not meet these requirements upon being advised of or otherwise becoming aware of any such issue;

(v) will include, as part of its publicly available website and in the manner specified in the Marketing Standards, a link to the Microsite or LDC Microsite Pages as applicable; and

(vi) will, in performing its obligations under this Master Agreement, including this Section 2.3 comply with the Marketing Standards. Without limiting the generality of the preceding sentence, the LDC will not use any marketing materials that do not comply with the Marketing Standards (including any use of a marketing template that has not been approved by the OPA) without first submitting to the OPA for, and obtaining from the OPA, approval to use such marketing materials. The OPA agrees to respond to any request for approval by the LDC within five (5) Business Days.

(c) As an alternative to using the Microsite or LDC Microsite Pages for displaying content describing the Initiatives on a website, the LDC may seek the OPA's approval, which approval will not be unreasonably withheld, to implement a customized website to describe the Initiatives, and to display LDC Marks and some custom content to the electricity consumers in the LDC's service area (the "**LDC Custom Microsite**"). If the LDC implements such a customized website, the LDC agrees that it will be responsible for: (i) hosting the LDC Custom Microsite; (ii) creating the content for the LDC Custom Microsite to describe all CDM Programs and Initiatives; and (iii) ensuring that the LDC Custom Microsite complies with the Marketing Standards. The LDC further agrees that the LDC Custom Microsite will utilize and be integrated with the Program Management System for the purposes of Applications and other processes in the same way that the Microsite or LDC Microsite Pages utilize and are integrated with the Program Management System. If the OPA approves such request, the OPA will use Commercially Reasonable Efforts to assist the LDC to link the LDC Custom Microsite with the Program Management System and to ensure that the Program Management System is built to function in such manner so as to allow the LDC

Custom Microsite to be linked to it, provided that the LDC will be responsible for the LDC's costs associated with the implementation of the LDC Custom Microsite, including, for greater certainty, all costs associated with the integration of the LDC Custom Microsite with the Program Management System and any third party licensing costs that apply to the LDC Custom Microsite and not the Microsite or LDC Microsite Pages.

2.4 Communication with Electricity Consumers

The Party that is primarily responsible for interaction with the public in the LDC's service area in respect of the Registered Initiatives will be identified in the applicable Initiative Schedule. If a Party receives any inquiries or complaints regarding any issue relating to or arising out of a Registered Initiative that is the responsibility of the other Party, including with respect to any of such other Party's third party service providers, such inquiries and complaints will be directed by the Party receiving such inquiry or complaint to the contact person of such other Party listed in Schedule A-3.

2.5 Technology Requirements

(a) The OPA will use Commercially Reasonable Efforts to, by January 3rd, 2011 or as soon as possible thereafter, implement and operate the Program Management System and provide the LDC with access to the Program Management System in accordance with Sections 2.5(a) and 2.5(b). The OPA will use Commercially Reasonable Efforts to ensure that the Program Management System will be designed to facilitate necessary functions relating to the operation and administration of the CDM Programs, including the submission of Applications, transmittal of reports and other information, reporting, and data storage and retrieval. Without limiting the generality of the foregoing:

(i) the OPA will use Commercially Reasonable Efforts to have available the functions necessary for consumer interface by January 3, 2011 in respect of the Registered Programs available as at such date;

(ii) the Program Management System will provide the LDC with access to unverified results achieved by the LDC for each Registered Initiative; and

(iii) the Program Management System will enable the LDC to access and export then-current data stored in the Program Management System that relates to Participants who are located in the LDC's service area.

(b) Following the implementation of the Program Management System, the OPA will use Commercially Reasonable Efforts to:

(i) operate, support and maintain the Program Management System for the duration of the Term, including maintaining appropriate security and integrity safeguards within the Program Management System for the purposes of maintaining the confidentiality of data in accordance with the provisions of Article 12;

(ii) target that the Program Management System will be available for 98% of the Term; and

(iii) target remediation of incidents that affect the Program Management System within a period of twenty-four (24) hours or such other reasonable period of time taking into account the severity of the incident.

(c) The OPA will:

(i) be responsible for any data entered into the Program Management System by the OPA, any OPA Other Service Provider, or any other third party acting on behalf of the OPA (which, for certainty, will not include any Local Distribution Company or any LDC Other Service Provider);

(ii) not insert or permit any third party for whom it is responsible at law (which, for certainty, does not include the LDC or any LDC Other Service Provider) to insert any Disabling Code into the Program Management System nor modify information on the Program Management System related to any Participant without such Participant's consent;

(iii) provide to the LDC forty-eight (48) hours advance notice of any scheduled (as opposed to emergency) maintenance to be performed on the Program Management System that will result in the Program Management System being unavailable along with an estimate of the duration of such unavailability; and

(iv) provide to the LDC prompt notice of an event or circumstance occurring that results, or is likely to result, in the Program Management System being unavailable.

(d) Following the implementation of the Program Management System, the LDC will use the functions available through the Program Management System for purposes relating to the delivery, operation, administration, processing of and reporting on Registered Initiatives. Without limiting the generality of the preceding sentence, the LDC will:

(i) follow and implement the Program Management System interface guidelines or other instructions, as may be amended or modified from time to time, received from the OPA and reasonably required or reasonably desirable to ensure the proper administration by the LDC of the Registered Initiative and the LDC's performance of its obligations under the Master Agreement using the Program Management System;

(ii) use the Program Management System to submit Applications, Participant Agreements, assessments, reports, and all other documentation or information required to be completed or provided by the LDC to the OPA in connection with each Registered Initiative; and

(iii) otherwise use the functionality that is available as part of the Program Management System from time to time during the Term for purposes relating to the delivery, operation, administration, processing of and reporting on Registered Initiatives by the LDC.

(e) With respect to the use of the Program Management System, including, for greater certainty, any applicable LDC Microsite Pages or LDC Custom Microsite:

(i) the LDC will:

(A) control access to and use of the Program Management System by LDC users, including LDC employees, contractors, agents and LDC Other Service Providers, including the management of user logon IDs and passwords and compliance with third party licence restrictions (where the OPA has advised the LDC of such thirty party licence restrictions), such as user limitations in respect of Microsoft or other third party licenses procured by the OPA for use by or on behalf of the LDC;

(B) ensure that all links and all other interfaces to each of its LDC Microsite Pages are compatible with the Program Management System;

(C) not insert or permit any third party for whom it is responsible at law (which, for certainty, does not include the OPA or any OPA Other Service Provider) to insert any Disabling Code into the Program Management System nor modify information on the Program Management System related to any Participant without such Participant's consent;

(D) use Commercially Reasonable Efforts to cooperate with the OPA and OPA Other Service Providers at the OPA's request with respect to the testing, operation, support and maintenance of the Program Management System, including, if applicable, participation in contingency planning tests or failovers and testing of fixes, updates, enhancements to and new releases for the Program Management System;

(E) in respect of any problem or suspected problem with the Program Management System:

(I) if such problem is discovered by the LDC, promptly notify the OPA of such problem; and

(II) use Commercially Reasonable Efforts where applicable and given the nature of the problem to cooperate with and assist the OPA to achieve resolution of such problems;

(ii) the LDC will be responsible for any data entered into the Program Management System by the LDC, any LDC Other Service Provider, or any other third party acting on behalf of the LDC (which, for certainty, will not include any other Local Distribution Company or OPA Other Service Provider); and

(iii) the LDC agrees that the OPA may, in its discretion, for emergency maintenance or reasons relating to suspected security breaches, fraud or unauthorized access or misuse, suspend access to any portion of the Program Management System, including, for greater certainty, any portion of the LDC Microsite Pages, without prior written notice to the LDC.

(f) If the Program Management System is out of service for more than a 48-hour period but less than ten (10) Business Days, the OPA will devise a reasonable work-around and the LDC will use Commercially Reasonable Efforts to comply with such work-around instructions provided by the OPA from time to time.

(g) If the Program Management System is out of service for greater than ten (10) Business Days, the OPA will devise a reasonable work-around and the LDC will use Commercially Reasonable Efforts to comply with such work-around instructions provided by the OPA from time to time. The OPA shall be responsible for all reasonable incremental expenses directly related to the LDC complying with such work around instructions.

2.6 OPA Third Party Service Providers

(a) The OPA may, in its discretion, retain third party service providers (each, an "**OPA Other Service Provider**") to perform any of its responsibilities under this Master Agreement. The OPA will require that each OPA Other Service Provider is suitably qualified, licensed and experienced, assumes responsibility and liability for the quality of all work and materials in relation to Eligible Measures that it supplies, and carries insurance consistent with applicable industry standards.

(b) At the OPA's request, the LDC will cooperate with and assist OPA Other Service Providers in order to coordinate the OPA's performance with the performance of the obligations of the LDC, including to the extent necessary for the foregoing purpose: (i) making available and providing information to the OPA and OPA Other Service Providers regarding any Registered Initiative; and (ii) upon the OPA's request, complying with the instructions of OPA Other Service Providers to the extent relevant to the proper implementation of the Registered CDM Programs.

(c) Except as contemplated by the terms of a Registered Initiative, the LDC will not provide instructions to any OPA Other Service Provider. If the LDC reasonably requires amendments to the duties performed by an OPA Other Service Provider or if the LDC has complaints regarding such OPA Other Service Provider, the

LDC will submit all such requests and complaints in writing to the OPA. The OPA will assess such requests and complaints and determine the corrective action, if any, required, after considering input from the LDC.

(d) The retention of an OPA Other Service Provider will not relieve the OPA from any obligation or liability under this Master Agreement. The OPA will remain responsible for the performance of all or any part of its obligations set out in this Master Agreement performed by any OPA Other Service Provider to the same extent as if such obligations were performed by the OPA. Any breach of this Master Agreement by any OPA Other Service Provider will be deemed to be a breach of this Master Agreement by the OPA.

2.7 Subcontracting by LDC

(a) The LDC may subcontract any of its responsibilities under this Master Agreement to an Affiliate or a third party (each, an "**LDC Other Service Provider**"). In procuring goods or services for purposes relating to any CDM Program or otherwise to the performance by the LDC of its obligations under this Master Agreement, the LDC will comply with the applicable requirements set forth in Section 4.1.

(b) The LDC will require that each LDC Other Service Provider is suitably qualified, licensed and experienced, assumes responsibility and liability for the quality of all work and materials in relation to Eligible Measures that it supplies and carries insurance consistent with applicable industry standards. Except as contemplated by the terms of a Registered Initiative, the OPA will not provide instructions to any LDC Other Service Provider.

(c) The LDC will use Commercially Reasonable Efforts to:

(i) obtain industry standard warranties from any LDC Other Service Provider with which it subcontracts for the installation of Eligible Measures and in respect of any materials or equipment installed in connection with an Eligible Measure; and

(ii) engage subcontractors and material or equipment suppliers jointly or otherwise in cooperation with other Local Distribution Companies in order to achieve cost efficiencies.

(d) The subcontracting of all or any part of the LDC's obligations set out in this Master Agreement to any LDC Other Service Provider will not relieve the LDC from any obligation or liability under this Master Agreement. The LDC will remain responsible for the performance of all or any part of its obligations set out in this Master Agreement performed by any LDC Other Service Provider to the same extent as if such obligations were performed by the LDC. Any breach of this Master Agreement by any LDC Other Service Provider will be deemed to be a breach of this Master Agreement by the LDC.

2.8 Prescribed Forms, Participant Agreements and Eligibility Criteria

(a) Subject to Section 2.8(b), where the Initiative Schedule for a Registered Initiative requires that a Prescribed Form is used, made available or entered into by the LDC with an Eligible Person:

(i) such requirement will be stated in such Initiative Schedule;

(ii) the Prescribed Form will made available by the OPA on the OPA Website; and

(iii) the LDC will not modify in any way such Prescribed Form prior to it being used, made available or entered into by the LDC with an Eligible Person.

(b) If the applicable Initiative Schedules expressly permit it, the LDC may opt not to use the form of Participant Agreement provided by the OPA for a Registered Initiative, in which case, the LDC will enter into its own form of Participant Agreement; provided, however, that:

(i) such form of Participant Agreement will contain, at a minimum and without modification, all of the provisions that are contained in the form of Participant Agreement made available by the OPA and identified as being mandatory provisions by the OPA;

(ii) the LDC will not include in its own form of Participant Agreement any provisions that could reasonably be expected to conflict or be inconsistent with a provision identified as mandatory pursuant to Section 2.8(b)(i).

(c) The LDC will administer each Participant Agreement in accordance with the terms and conditions thereof and will use Commercially Reasonable Efforts to enforce its rights and perform its obligations thereunder.

(d) Except in the case of a breach or default by a Participant under a Participant Agreement pursuant to which the LDC has decided, acting reasonably, to terminate such Participant Agreement, the LDC will not cause, consent to, or permit, any termination of a Participant Agreement or any material amendment, modification, variance or waiver of timely compliance with any terms or conditions of a Participant Agreement, other than amendments or modifications to cure any defective provisions contained therein. For certainty, any proposed amendment or variance of a provision identified as mandatory pursuant to Section 2.8(b) is deemed to be material.

(e) Except where a Prescribed Form or Eligibility Criteria is changed as part of a Change pursuant to Section 4(b)(iii), (iv) or (v) of Schedule A-4, a Prescribed Form or Eligibility Criteria may be amended, modified, supplemented, replaced, added or deleted by the process set out in this Section 2.8(e). Either the OPA or the EDA Representative may trigger a change to a Prescribed Form by delivering a letter to the other which (A) requests changes to, or the addition or deletion of, the Prescribed Form and the reasons for the requested changes, (B) (other than in the case of a deletion of an entire Prescribed Form) attaches a blackline of the Prescribed Form showing the requested changes, and (C) proposes the date by which such changes will be effective. Within 10 Business Days of receipt of the letter requesting the changes to the Prescribed Form, the OPA or the EDA Representative, as applicable, each acting reasonably, will respond to the requesting party, and either accept or reject the requested changes. In the case of rejection, the OPA or the EDA, as applicable, will provide reasons for the rejection. If the OPA or the EDA Representative, as applicable, rejects the requested changes, the process set out in this Section 2.8(e) will terminate immediately. For certainty, the changes to the Prescribed Form may be revised and proposed again pursuant to the process set out in this Section 2.8(e). If the OPA or the EDA Representative, as applicable, does not respond within 10 Business Days, then the OPA or the EDA Representative, as applicable, will be deemed to agree with the proposed changes to the Prescribed Form, which will be binding on the OPA and the LDCs. For certainty, where a Prescribed Form or Eligibility Criteria is changed as part of a Change as described in Section 4(b)(iii), (iv) or (v) of Schedule A-4, the process set out in this Section 2.8(e) shall not be applicable.

2.9 Compliance with Laws and Regulations

(a) The LDC will at all times during the Term be a Local Distribution Company and be licensed by the OEB as an electricity distributor.

(b) The OPA will at all times during the Term be licensed by the OEB to exercise its powers and perform its duties under the *Electricity Act, 1998*.

(c) Each Party will comply, in all material respects, with all Laws and Regulations required to be complied with in the performance of its obligations hereunder.

(d) Each Party will obtain and maintain in good standing, each licence, permit, certificate, registration, authorization, consent or approval of any Governmental Authority, as applicable, to the extent necessary or appropriate to carry out its obligations hereunder.

2.10 Company Representative

The LDC and the OPA will each, by notice to the other, appoint, from time to time, a representative (a "**Company Representative**"), who will be duly authorized to act on behalf of the Party that has made the appointment, and with whom the other Party may consult at all reasonable times, and whose instructions, requests and decisions, provided the same are in writing signed by the respective Company Representative, will be binding on the appointing Party as to all matters pertaining to this Master Agreement; provided, however, that the Company Representatives will not have the power or authority to amend this Master Agreement except as provided in Section 1.7. Except as otherwise provided herein, the Company

Representatives will be the first point of contact between the Parties. The initial Company Representative for each Party is set forth in Schedule A-3, and in the case of the LDC, such initial Company Representative is deemed to be the LDC's conservation officer.

ARTICLE 3
CHANGE MANAGEMENT PROCESS

3.1 Change Terms

(a) Except as provided in Section 3.1(b) and Section 3.1(c), the terms and conditions set out in Schedule A-4 (the "**Change Terms**") will apply to each request for a Change.

(b) The Change Terms will not apply to any of the following:

(i) the termination of any existing Initiative, Registered Initiative, CDM Program or Registered CDM Program or the deletion of any existing Initiative Schedule applicable to a Registered Initiative in any of the foregoing cases in accordance with Section 3.3(a)(ii), Section 4.3, Section 7.3 or any provision of Article 10; or

(ii) any addition of Registered Initiatives or Registered CDM Programs pursuant to Section 3.2 or Section 3.3(a)(i).

(c) Unless otherwise expressly provided in this Master Agreement, all other amendments or supplements to this Master Agreement will be made in accordance with Section 1.7.

(d) Each Party acknowledges and agrees that it will be bound by any rights and obligations that it may become entitled to and liable to perform pursuant to the Change Terms. Each Party will take all actions within its control to cause the EDA Representative to implement the Change Terms. It is the intention of the Parties that the Change Terms and the terms of Section 3.1 will be binding upon the OPA and all Participating LDCs that participate in a Registered CDM Program or a Registered Initiative.

3.2 C&I, Industrial and Low Income Programs

(a) The Parties acknowledge that:

(i) [Intentionally deleted]

(ii) the New Construction Initiative and the Existing Building Commissioning Incentive Initiative have been finalized and constitute Registered Initiatives forming part of the C&I Program; and

(iii) the Industrial Program and the Low Income Program have been finalized and are Registered CDM Programs.

3.3 Changes by LDC Regarding Registration

(a) At any time and from time to time during the Term, the LDC may:

(i) if it has not Registered for participation in such CDM Program pursuant to Section 3.2 (or has so Registered but subsequently terminated its participation pursuant to Section 3.3(a)(ii)), effective as of the first day of a calendar month, Register for participation in a CDM Program by providing the OPA with notice of its intention to Register for such CDM Program at least sixty (60) days prior to the intended effective date; and

(ii) terminate its participation in a Registered CDM Program, or a Registered Initiative forming part of a Registered CDM Program, provided that it has participated in such Registered CDM Program or Registered Initiative, as the case may be, for at least one year (or part thereof in the case of a Registered CDM Program or Registered Initiative, as the case may be, that the LDC participates in pursuant to Section 3.2), by providing the OPA with notice of its intention to terminate its participation in such Registered CDM Program or Registered Initiative, as the case may be, at least sixty (60) days prior to the intended effective date of such termination, and the provisions of Section 10.3(b) will become effective, *mutatis mutandis*, as if the OPA had terminated the Registered CDM Programs, Registered Initiative, or Initiative Schedules pursuant to Section 10.3(a).

(b) Once the LDC has Registered to participate in a CDM Program in accordance with Section 3.3(a), each Initiative pertaining to such CDM Program will become a Registered Initiative and the Initiative Schedules for which will be deemed to form part of this Master Agreement. For greater certainty, the submission of a Registration by the LDC in respect of such CDM Program after the Effective Date will not reduce or increase the amount of the Program Administration Budget of the LDC but will result in the payment schedule for such CDM Program in Tables 1 or 2 of Schedule A-5 being revised by the OPA to proportionately increase the remaining semi-annual advances on the remaining first Business Days of January and July in the remainder of the Term to permit such amount to be paid in full during the remaining Term. The first semi-annual payment will be made no later than twenty (20) days after the date that the LDC is so Registered and the LDC has delivered an invoice for such payment in accordance with Section 4.7, and the remaining payments will be made on the remaining first Business Days of January and July.

ARTICLE 4
FUNDING AND PAYMENT TERMS

4.1 General Principles Applicable to LDC's Use of OPA-Provided Funding

(a) The LDC represents, warrants and covenants that it has, and will at all times during the Term maintain, internal by-laws, policies or other binding rules designed to ensure prudent use by the LDC of ratepayer funds, including rules relating to: (A) the LDC's procurement of products and services from third party service providers; and (B) expenses that, if incurred by or on behalf of the LDC, its employees or representatives, are properly incurred and therefore eligible for reimbursement by the LDC (collectively, the "**LDC Expenditure Policies**") that:

(i) are consistent with Laws and Regulations; and

(ii) have been approved by the LDC's board of directors (or equivalent) or an individual or committee authorized by such board.

(b) The LDC will use the funds provided to it by the OPA hereunder in good faith and in a reasonable and prudent manner in accordance with the LDC Expenditure Policies and only for purposes solely related to the OPA-Contracted Province-Wide CDM Programs. Without limiting the generality of the preceding sentence, the LDC will:

(i) use the Program Administration Budget only for LDC Eligible Program Administration Expenses;

(ii) not exceed the permitted amounts for an LDC Eligible Program Administration Expense provided for in the LDC Expenditure Policies; and

(iii) follow competitive procurement processes unless a competitive procurement process is not required for a specific transaction pursuant to the LDC Expenditure Policies.

4.2 Program Administration Budget Amounts

(a) The OPA will provide pre-funding in accordance with Table 1 of Exhibit A-5-1 to Schedule A-5 to the LDC for LDC Eligible Program Administration Expenses incurred by the LDC during the Term in the performance of its obligations in respect of each Registered CDM Program. The total of such pre-funding in respect of a Registered CDM Program will not exceed such CDM Program's Program Administration Budget, as set forth in Table 1 of Exhibit A-5-1 of Schedule A-5, as such amount may be adjusted in accordance with the terms hereof.

(b) Except as provided in this Section 4.2 for the C&I Program, the OPA will advance to the LDC semi-annually, but not earlier than the first Business Day of each January and July of the Term, an amount calculated as the percentage of the Program Administration Budget for each applicable Registered CDM Program for the applicable six-month period as set forth in Table 1 of Schedule A-5; provided, however, that the OPA will only be required to advance funds pursuant to this Section 4.2(b) in respect of a CDM Program from the time that such CDM Program is Registered as provided in Section 3.2 or Section 3.3, as applicable. If the LDC has Registered to deliver the C&I Program when it comprises only the Initial C&I Initiatives, the OPA will advance on or before the 20th day following the C&I Program becoming a Registered CDM Program and receipt by the OPA of the invoice required by Section 4.7 half of the Program Administration Budget pre-funding amount payable for the first six-month period of the Term as set forth in Table 1 of Schedule A-5. On or before the 20th day following the Remaining C&I Initiatives becoming Registered Initiatives pursuant to Section 3.2(a) and receipt by the OPA of the invoice required by Section 4.7, the OPA will advance the remaining half of such first Program Administration Budget pre-funding amount. The LDC may only use the funds advanced pursuant to this Section 4.2(b) to pay LDC Eligible Program Administration Expenses as they become due. The LDC will not use any part of the Program Administration Budget for a Registered CDM Program to pay LDC Eligible Program Administration Expenses incurred in connection with another Registered CDM Program or any other matter.

(c) Notwithstanding Sections 4.2(a) and (b), the LDC shall, following written notice to the OPA (a "**PAB Reallocation Notice**") be permitted to use all or a portion of of the Program Administration Budget for a Registered CDM Program to pay LDC Eligible Program Administration Expenses incurred in connection with another Registered CDM Program. A PAB Reallocation Notice shall include the Registered CDM Program and Registered Initiative in respect of which the Program Administration Budget is being reduced and the amount of such reduction and the Registered CDM Program and Registered Initiative in respect of which the Program Administration Budget is being increased and the amount of such increase. For clarity, this Section 4.2(c), shall be subject to Sections 2.1 and 3.3 and shall be without prejudice to the LDC's obligations thereunder to continue to offer and deliver all Registered CDM Programs and Registered Initiatives.

4.3 Changes by LDC Regarding PAB

(a) Only in accordance with the procedure set out in Section 4.3(c) the LDC may request an increase in the amount of the Program Administration Budget in respect of one or more Registered CDM Programs. Such request may be made only once per calendar year, between January 1 and March 31, inclusive.

(b) Only in accordance with the procedure set out in Section 4.3(c), notwithstanding Section 4.3(a), if a new Initiative or CDM Program is introduced as a Change in accordance with Section 3.1(a) and the LDC Registers for such new Initiative or CDM Program, the LDC may at any time thereafter make a single request for an increase in the amount of the Program Administration Budget in respect of such Registered Initiative or Registered CDM Program.

(c) A request under Section 4.3(a) or 3.3(b) (a "**PAB Modification Request**") must be submitted in the Prescribed Form. Within 20 Business Days of the OPA's receipt of the PAB Modification Request, the OPA shall do one or more of the following:

(i) agree to the PAB Modification Request by way of a notice to the LDC showing the increase to the applicable Program Administration Budget by way of an amended Exhibit A-5-1 to Schedule A-5 of this Agreement and a blackline showing such requested increase;

(ii) deny the PAB Modification Request and provide written reasons for its decision to deny the request;

(iii) request further information from the LDC for the purposes of evaluating the PAB Modification Request, such information to be provided to the OPA by the LDC no later than 10 Business days following such request by the OPA, unless otherwise agreed to by the OPA; or

(iv) request a Senior Conference in respect of the PAB Modification Request.

(d) When further information from the LDC is requested by the OPA in accordance with Section 4.3(c)(iii), and the LDC has submitted the requested information, the procedure in Section 4.3(c) shall thereafter apply as if the LDC had made a new PAB Modification Request, *mutatis mutandis*. If the OPA requests further information a second time from the LDC in accordance with Section 4.3(c)(iii), and the LDC has submitted the requested information, the procedure in Section 4.3(c) shall thereafter apply again as if the LDC had made a new PAB Modification Request, *mutatis mutandis*, with the exception that, after the second request for information from the LDC, the OPA may not request further information from the LDC in accordance with Section 4.3(c)(iii).

(e) Any failure by the LDC to provide the requested information in accordance with Section 4.3(c)(iii) shall be deemed to be a withdrawal of the PAB Modification Request.

(f) At any time following 20 Business Days of the OPA's receipt of the PAB Modification Request, in the event that the OPA has not agreed to the PAB Modification Request, either the OPA or the LDC may request a Senior Conference in respect of the PAB Modification Request.

(g) In considering any PAB Modification Request under this Section 4.3, the OPA shall take into consideration, *inter alia*, the requested modified PAB for the Registered CDM Program in proportion to the LDC's Peak Demand Savings and/or Electricity Savings, as applicable ("Proportion"), as compared with the

Proportion in respect of other LDCs with a similarly sized customer base and location within the Province of Ontario for the same Registered CDM Program.

(h) The LDC shall separately invoice the OPA for any approved PAB Modification Request in accordance with Section 4.7.

(i) The LDC may, by submitting a Prescribed Form, to the OPA require a decrease in the amount of the Program Administration Budget in respect of a Registered CDM Program. Within 20 Business Days after the OPA's receipt of the LDC's notice, the OPA will send a notice to the LDC showing the required decrease to the applicable Program Budget by way of an amended Exhibit A-5-1 to Schedule A-5 of this Agreement, and a blackline showing such decrease. The LDC may require such decrease only once per calendar year, between January 1 and March 31, inclusive.

4.4 Participant Based Funding and Participant Incentives Payments

The OPA will pay to the LDC monthly in accordance with the applicable Initiative Schedule the Participant Based Funding Amount and Participant Incentives, if any, for each Registered Initiative. For certainty, not all Initiatives provide for Participant Based Funding Amounts or Participant Incentives.

4.5 Capability Building Funding Payments

The OPA will pay to the LDC monthly in accordance with the applicable Initiative Schedule the Capability Building Funding Amount, if any, for each Registered Initiative. For certainty, not all Initiatives provide for Capability Building Funding Amounts.

4.6 Cost Efficiency Incentive

The LDC is entitled to receive and retain from the aggregated Program Administration Budgets in respect of each Registered CDM Program the funds that remain unspent and not payable as incurred but unpaid LDC Eligible Program Administration Expenses at the end of the Term, an incentive (the "**Cost Efficiency Incentive**") as calculated pursuant to Schedule A-5, provided that:

(a) no LDC Event of Default has occurred and is continuing;

(b) the aggregate of the LDC Eligible Program Administration Expenses in respect of the aggregate of all Registered CDM Programs are less than the aggregate of the Program Administration Budgets for all such Registered CDM Programs;

(c) the LDC has used Commercially Reasonable Efforts to achieve the Electricity Savings Target and the Peak Demand Savings Target for each such Registered CDM Program; and

(d) such calculation shall be made in respect of all Registered CDM Programs that have not been terminated pursuant to Article 10 or otherwise.

4.7 Payment Procedure and Invoicing

(a) The OPA will not be obligated to pay any amount pursuant to Sections 4.2 to 4.6, inclusive, unless it has received from the LDC invoices issued in accordance with this Section 4.7 with respect to Program Administration Budget pre-funding, Participant Based Funding Amounts, Capability Building Funding Amounts and Participant Incentives (in each case, plus Applicable Taxes) payable to the LDC by the OPA, as applicable.

(b) The OPA will use Commercially Reasonable Efforts to provide functionality in the Program Management System to enable the creation and administration of billing reports for each Registered CDM Program ("**Billing Reports**"). Following notice from the OPA of the implementation of this functionality, the LDC will use the functions relating to the creation and administration of Billing Reports pursuant to the reasonable instructions received from the OPA, as such instructions may be reasonably amended or modified from time to time.

(c) The LDC will invoice the OPA with respect to all Program Administration Budget pre-funding, changes to the Program Administration Budget in accordance with Sections 3.3 and 4.3, Participant Based Funding Amounts, Capability Building Funding Amounts and Participant Incentives, and each invoice (other than for Program Administration Budget amounts) must attach the Billing Report that is generated by the Program Management System pertaining to such invoiced amounts. For certainty, invoices for Program Administration Budget pre-funding (but not for changes to Program Administration Budgets in accordance with Sections 3.3 and 4.3) are for administration purposes and supporting information is not required to be submitted therewith by the LDC.

(d) Prior to the implementation of the Billing Report functionality of the Program Management System, or if the OPA notifies the LDC that the Program Management System is not in service, the LDC will prepare invoices for submission to the OPA and will attach all supporting documentation and information to the invoice, all in form and substance acceptable to the OPA, acting reasonably, pursuant to this Section 4.7 and as may be further provided in the respective Initiative Schedules.

(e) The LDC is entitled to invoice the OPA at any time for the period of time set forth in the invoice (the "**Billing Period**") for:

(i) payment of the percentage of the Program Administration Budget for each Registered CDM Program payable to the LDC in the Billing Period (which must correspond with the payment schedule in Tables 1 or 2 of Schedule A-5);

(ii) the payment of any approved PAB Modification Request in accordance with Section 4.3;

(iii) payment of the Participant Based Funding Amount or the Capability Building Funding Amount, if any, for the Registered Initiatives for which the LDC performed its obligations in such Billing Period;

(iv) advanced funding of the Participant Incentives that the LDC is required to pay to Participants pursuant to a Participant Agreement entered into by the LDC in respect of the Registered Initiatives; and

(v) funding of the Participant Incentives that the LDC is required to pay to Participants, or that the LDC directs the OPA to pay to a Participant or third party, pursuant to a Participant Agreement following the implementation of Eligible Measures pursuant to the Participation Agreement entered into by the LDC in respect of the Registered Initiatives,

(the total of such amounts being the "**Funding Amount**"). The LDC will provide one invoice to the OPA in respect of each Registered CDM Program for the Funding Amount for such Billing Period, clearly stating the Registered Initiatives and the types of payments pursuant to Sections 4.2 to 4.6, inclusive, comprising such Funding Amount, and as such invoice and the invoicing requirements in respect thereof, if any, may be provided for in the applicable Initiative Schedule.

(f) Subject to Exhibit A-5, Table 1, the LDC will be paid by the OPA on or before the twentieth day (the "**Payment Date**") following receipt of an Invoice in accordance with this Section 4.7.

(g) The OPA will have no obligation to pay any amount invoiced if the invoice was delivered to the OPA more than one hundred and fifty (150) days following the date on which the LDC's right to invoice the OPA for such payment arose, regardless of the invoice date.

(h) The OPA may dispute any part of an invoice or withhold payment of any portion of any amounts due to the LDC under this Master Agreement if the OPA asserts in good faith that:

(i) any of the amounts requested for payment are not LDC Eligible Program Administration Expenses, Participant Based Funding Amounts, Capability Building Funding Amounts, Participant Incentives or are otherwise not in compliance with this Master Agreement; or

(ii) an invoice or supporting materials submitted by the LDC are not in accordance with the criteria specified in this Master Agreement.

(i) The OPA will provide notice to the LDC of any such dispute or withholding within ten (10) Business Days of receipt of such invoice together with reasons for such rejection. The LDC will provide any additional information requested or take such other steps necessary to substantiate the invoice or correct any deficiency or error therein. The OPA may withhold payment of the disputed amount until the dispute or failure is resolved in accordance with this Section 4.7(i) and, for greater certainty, any such withholding will not thereby constitute or be deemed to constitute a default or breach by the OPA of this Master Agreement. If within twenty (20) Business Days of the LDC's receipt of such notice the Parties have not resolved the dispute or failure or the OPA has not notified the LDC that it will pay the withholding, the Parties will refer the dispute for resolution in accordance with the process set out in Article 13. Failure by the OPA to give notice of a dispute or failure or the payment by the OPA of an amount invoiced will not affect the OPA's right to later initiate a Dispute with respect to such amount, provided the OPA exercises the foregoing right within one hundred and twenty (120) days after having actual knowledge (including through the exercise of its audit rights pursuant to Section 7.1) that such amount should be the subject of a Dispute.

4.8 Representations in Invoices

(a) Upon submission by the LDC of each invoice submitted pursuant to Section 4.7(a), such invoice will be deemed to contain the following representations from the LDC:

"LDC hereby represents to the Ontario Power Authority and acknowledges that the Ontario Power Authority is relying on such representations:

1. This invoice is in relation to a Registered CDM Program.

2. This invoice and the information provided herein are true and complete in all materials respects.

3. The amounts in this invoice are all Program Administration Budget advances, Participant Based Funding Amounts, Capability Building Funding Amounts or Participant Incentives payable to the LDC in accordance with the terms and conditions of such Registered CDM Program and/or Registered Initiative.

4. The LDC is in compliance with all of its obligations under the Master Agreement."

(b) If the LDC is unable to provide the representation contemplated by 4.8(a), it will provide notice to the OPA with a reasonably detailed explanation.

4.9 Responsibility for Taxes

(a) In addition to any amounts payable to the LDC under this Agreement and in connection with the performance of its obligations or a Participant Incentive hereunder, the OPA will pay to the LDC any applicable HST and any other applicable sales or use taxes ("**Applicable Taxes**"). Where mandated, any Applicable Taxes collected by the LDC under this Section 4.9 will be held in trust and timely accounted for in a return filed by it with the Canada Revenue Agency, or other appropriate Governmental Authority, for the reporting period in which the liability for such Applicable Taxes arose. The LDC will provide to the OPA sufficient supporting documentation, as requested by the OPA, to facilitate and support the OPA in claiming input tax credits in respect of such amounts paid. In addition, if the OPA has reasonable grounds to challenge whether Applicable Taxes should be paid by the OPA on any such amounts, the LDC will use Commercially Reasonable Efforts to provide assistance to the OPA with such challenge.

(b) The LDC will be responsible for all Taxes and amounts exigible on, imposed in respect of or relating to the revenues earned by the LDC in the performance of its obligations hereunder or attributable to any payments pursuant to Sections 4.2 to 4.6, inclusive, Taxes based on its own capital or net income, employment Taxes in respect of the LDC's personnel, and Taxes on any property owned by the LDC. In addition, the LDC will be responsible for all Applicable Taxes incurred by the LDC in the performance of its obligations hereunder. The LDC will be responsible for the arrangements to pay all such Taxes and Applicable Taxes in a timely manner when due and payable.

4.10 Funding Payment Recovery

If the LDC recovers funds from a Participant pursuant to a Participant Agreement or any other arrangement relating to a Registered Initiative, including by the enforcement of the LDC's rights pursuant to a Participant Agreement or otherwise, such funds will be repaid by the LDC to the OPA forthwith following receipt by the LDC.

4.11 Post-Termination Administration Costs

(a) The LDC will provide to the OPA on or before February 28, 2015 its accounting of the LDC Eligible Program Administration Expenses contemplated by Section 8.1(a)(i) ("**2015 Accounting**"). Upon the OPA's receipt and approval of the LDC's 2015 Accounting, the Cost Efficiency Incentive for the period prior to January 1, 2015 will be calculated pursuant to Section 4.6 and Schedule A-5 and the LDC shall repay to the OPA the positive difference, if any, between the aggregate Program Administration Budget amounts advanced to the LDC for all Registered CDM Programs less the Cost Efficiency Incentive and the aggregate of the LDC Eligible Program Administration Expenses for such Registered CDM Programs in respect of such period.

(b) As a final reconciliation of the Post-Termination Administration Costs, the LDC will provide to the OPA after December 31, 2015 and on or before February 28, 2016 an accounting of its actual Post-Termination Administration Costs incurred during the preceding calendar year and an updated estimate of the remaining Post-Termination Administration Costs (the **"2016 Estimate"**), if any. Upon the OPA's receipt of the foregoing information and approval of the LDC's 2016 Estimate, the Cost Efficiency Incentive calculation will be recalculated pursuant to Section 4.5 and Schedule A-5 using the actual Post-Termination Administration Costs incurred during 2015 and the approved 2016 Estimate instead of the 2015 Estimate. If as a result of this reconciliation the calculation of the Cost Efficiency Incentive produces a different result than the calculation conducted in Section 4.11(a), the relevant Party will pay to the other Party the difference, subject to Section 4.11(d).

(c) In the event a Registered CDM Program was terminated prior to the end of the Term, the LDC will provide to the OPA after December 31, 2015 and on or before February 28, 2016, together with the information contemplated in Sections **Error! Reference source not found.**, if any, an accounting of its actual Post-Termination Administration Costs for the period commencing on the effective date of the termination of such Registered CDM Program and ending December 31, 2015, together with an estimate of any remaining Post-Termination Administration Costs relating to such Registered CDM Program. Upon the OPA's receipt of the foregoing information and approval of the LDC's estimate, if any, if the LDC's original estimated Post-Termination Administration Costs is greater than the actual Post-Termination Administration Costs and updated estimate, the LDC shall repay to the OPA the difference.

(d) For certainty, nothing in this Section 4.11 will result in the OPA providing funding in excess of such CDM Program's Program Administration Budget.

ARTICLE 5
OWNERSHIP AND LICENCE

5.1 Ownership of OPA Property

(a) As between the LDC and the OPA, the OPA and its licensors are and will be the exclusive owner of all of the following and all Intellectual Property Rights therein (collectively, the "**OPA Property**"):

(i) all hardware, software, systems, documentation, content, Trade-marks, Confidential Information or other information or intellectual property (including business rules and business processes) that is or has been procured, created or developed: (A) by the OPA (whether alone or jointly with one or more Persons, including the LDC and the OPA Other Service Providers, and whether such activities occurred prior to or after the Effective Date and independent of or in connection with the CDM Programs), including the Program Management System; or (B) by the LDC or any LDC Other Service Provider that relates to the CDM Programs and uses funding provided to the LDC by the OPA pursuant to this Master Agreement including case studies prepared by the LDC or LDC Other Service Providers and marketing materials developed by the LDC or LDC Other Service Providers for any Registered Initiatives (other than LDC Marks used in such marketing materials);

(ii) all OPA Marks; and

(iii) all reports and other information created, generated, output or displayed by the Program Management System or as a result of the delivery of the CDM Programs.

(b) All right, title and interest, including all Intellectual Property Rights, in OPA Property will vest in the OPA, immediately upon creation and regardless of the state of completion of such OPA Property.

(c) The LDC will acquire no rights to any OPA Property other than the licence rights expressly granted in Section 5.4.

5.2 Notice, Assignment and Waiver

(a) The LDC will notify the OPA of any OPA Property procured, created or developed by the LDC or any LDC Other Service Provider, including case studies prepared by the LDC or LDC Other Service Providers and marketing materials developed by the LDC or LDC Other Service Providers for any Registered Initiatives (other than LDC Marks used in such marketing materials).

(b) As partial consideration for the payments described in Article 4, the LDC:

(i) hereby assigns and transfers to the OPA;

(ii) agrees to assign and transfer to the OPA; and

(iii) agrees to require LDC Other Service Providers to assign and transfer to the OPA,

as and when created, all right, title and interest, including Intellectual Property Rights, throughout the world in and to all OPA Property to the extent any right, title, interest or Intellectual Property Right in OPA Property does not automatically and immediately vest in the OPA.

(c) The LDC will require all LDC personnel and personnel of LDC Other Service Providers to waive, for the benefit of the OPA, their respective moral rights in and to the OPA Property.

5.3 Ownership of LDC Property

(a) The LDC is and will be the exclusive owner of all of the following and all Intellectual Property Rights therein (collectively, the "**LDC Property**"):

(i) all hardware, software, systems, documentation, content, Trade-marks, Confidential Information or other documentation or intellectual property (including business rules and business processes) that is or has been procured, created or developed by the LDC and that was not procured, created or developed using funding provided to the LDC by the OPA pursuant to this Master Agreement (whether alone or jointly with one or more Persons, other than the OPA or an OPA Other Service Provider, and whether such activities occurred prior to or after the Effective Date and independent of or in connection with the CDM Programs), other than OPA Property;

(ii) all LDC Marks; and

(iii) all marketing collateral or other materials containing any LDC Marks and no OPA Marks.

(b) All right, title and interest, including all Intellectual Property Rights, in the LDC Property will vest in the LDC, immediately upon creation and regardless of the state of completion of such the LDC Property.

(c) The OPA will acquire no rights to any LDC Property other than the licence rights expressly granted in Section 5.5.

5.4 Grant of Licences by OPA to the LDC

(a) The OPA grants to the LDC, during the Term, a fully paid-up, royalty-free, non-exclusive, non-transferable licence to:

(i) access, use and copy OPA Property (other than any OPA Marks), to the extent required by the LDC in order to market, support, implement and deliver the Registered Initiatives; and

(ii) allow LDC Other Service Providers to exercise the rights referred to in Section 5.4(a)(i) for the purposes set out in Section 5.4(a)(i).

(b) The OPA grants to the LDC, beginning on the Effective Date and ending on December 31, 2015, a non-exclusive, non-transferable, royalty-free, revocable licence to display the OPA Marks solely in connection with the performance by the LDC of its obligations in Section 2.3(b). All such displays of the OPA Marks must comply with the applicable Marketing Standards.

5.5 Grant of Licences by the LDC to the OPA

(a) The LDC grants to the OPA, an irrevocable, fully paid-up, royalty-free, non-exclusive licence during the Term to:

(i) access, use and copy all LDC Property (other than LDC Marks) to the extent required by the OPA in order to design, develop, market, support, implement and deliver the CDM Programs and Initiatives; and

(ii) allow OPA Other Service Providers to exercise the rights referred to in Section 5.5(a)(i) for the purposes set out in Section 5.5(a)(i).

(b) The LDC grants to the OPA, beginning on the Effective Date and ending on December 31, 2015, a non-exclusive, non-transferable, royalty-free, revocable licence to display the LDC Marks solely in connection with the performance by the OPA of its obligations in Section 2.3(a). All such displays of the LDC Marks will comply with the reasonable guidelines with respect to the display of the LDC Marks provided by the LDC to the OPA from time to time.

5.6 Grant of Sublicence by the OPA to the LDC

In addition to the terms set forth in Section 5.4(b), the following terms apply with respect to the Ministry Marks:

(a) The OPA hereby grants to the LDC a fully paid-up, royalty-free, non-exclusive, non-transferable, revocable sublicence (the "**Sublicence**") to use, advertise and display the Ministry Marks in association with the CDM Programs beginning on the Effective Date and ending on December 31, 2015.

(b) The Ministry Marks are key visual identifiers of the CDM Programs. The form of each of the Ministry Marks is set out in the attached Schedule A-7. The specifications of each of the Ministry Marks, including colour and font, are also set out in Schedule A-7. The Ministry Marks must be identified with the footnote "A mark of Her Majesty the Queen in right of Ontario and protected under Canadian trademark laws. Used under sublicence." or such other footnote set forth in the Marketing Standards from time to time.

(c) The LDC acknowledges that the Ministry Marks and the whole of the goodwill associated therewith, whether now existing or arising in the future, are the exclusive property of Her Majesty the Queen in right of Ontario, as represented by the Ministry of Energy. The LDC will acquire no right, title or interest in or to the Ministry Marks, and any and all goodwill associated therewith will enure exclusively to the benefit of the Ministry of Energy.

(d) Each and every use by the LDC of one or more of the Ministry Marks must comply with all of the conditions set out below:

(i) the use of the Ministry Marks must be in accordance with the form and specification set out in Schedule A-7 (unless otherwise directed under Section 5.6(f)). Any modification of the Ministry Marks is specifically prohibited, except that the Ministry Marks, when used as word marks, may appear in any form;

(ii) the LDC will not register, or apply for the registration of, any trade-mark, corporate name, trading style or domain name integrating, in whole or in part, the Ministry Marks, or any confusingly similar trade-marks, corporate names, trading styles or domain names;

(iii) the LDC will not use the Ministry Marks in a manner which could, in the OPA's reasonable opinion, bring the Ministry Marks, the OPA, or the Ministry of Energy into disrepute or which could otherwise damage the goodwill attaching to the Ministry Marks;

(iv) the use of the Ministry Marks must be in a context that is factually correct and not misleading;

(v) the Ministry Marks may be used solely for the purposes of advertising and promotional activities that are related to the CDM Programs; and

(vi) the use of the Ministry Marks must comply with all federal, provincial and municipal laws and regulations.

(e) From time to time, if requested by the OPA, the LDC will provide to the OPA samples of any advertising, promotional materials, signs, displays or other materials on which the Ministry Marks are used or displayed in connection with the offering for performance or performance of any services. From time to time, if requested by the OPA, upon reasonable advance notice from the OPA, the LDC will allow the OPA to inspect the premises of the LDC, or any other premises where wares bearing the Ministry Marks are being distributed or where services are being performed in association with the Ministry Marks to ensure that the LDC is maintaining the standard and quality of products and services required by the OPA.

(f) If directed to do so by the Ministry of Energy, the OPA or its authorized representative may give directions to the LDC relating to the colour, font, proportion and correct usage standards of the Ministry Marks, and all such directions will be followed promptly by the LDC after a reasonable notice period to be agreed on between the LDC and the OPA.

(g) The LDC will keep proper records related to each use of the Ministry Marks in accordance with Section 7.1 for the term of the Sublicence and for the following three (3) years, and the records will be open to audit and inspection by the OPA in accordance with that Section.

(h) The LDC will promptly notify the OPA in writing of: (i) any actual, suspected or threatened infringement of the Ministry Marks of which the LDC becomes aware; and (ii) any allegation or complaint made to the LDC by any third party that the Ministry Marks are invalid, that use of the Ministry Marks infringes any third party rights, or that the Ministry Marks are confusingly similar to any other trade-mark or trade name. The LDC will not make any admissions in respect of these matters other than to the OPA and will, in each case, provide the OPA with all relevant information in its possession at the sole cost and expense of the OPA. The LDC may not institute any proceedings with respect to any actual or suspected infringement of the Ministry Marks without the prior written consent of the OPA.

(i) The OPA may, on five (5) months prior notice to the LDC, terminate the Sublicence at any time for any reason.

(j) On the expiration or termination of the OPA's license for the Ministry Marks and/or Sublicence, as the case may be, set out in this Article 5, the LDC will cease to use all the Ministry Marks, and will destroy all copies of the Ministry Marks in its possession or under its control.

5.7 Use of Program Personal Information

Each Party will have the right to use Program Personal Information (in individual or aggregate form) in connection with the exercise of its rights or performance of its obligations under this Master Agreement. In addition, the OPA will have the right to use Program Personal Information for internal purposes in connection with the fulfilment of its mandate and objectives relating to electricity systems in Ontario.

5.8 Mutual Representations and Warranties

(a) The OPA represents and warrants that it has obtained from third parties all authority, power and right to grant to the LDC the licences set forth in Section 5.4 and the Sublicence.

(b) The LDC represents and warrants that it has obtained from third parties all authority, power and right to grant to the OPA the licences set forth in Section 5.5.

ARTICLE 6
ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

(a) Except with the prior written consent of the OPA, such consent not to be unreasonably withheld, all Environmental Attributes arising in respect of Electricity Savings for which a Participant Incentive has been paid or in respect of equipment or appliance replacement or decommissioning funded by the OPA, whether existing now or arising in the future (the "**OPA Environmental Attributes**") will be owned by the OPA, and neither the LDC nor the Participant will have an entitlement to any such OPA Environmental Attributes. It will not be unreasonable for the OPA to withhold its consent in order to comply with Laws and Regulations, which for the purposes of this Section only includes any written policy instructions provided by the Ontario provincial government, including the Ministry of Energy. All other Environmental Attributes arising in relation to a Participant will be owned by the Participant and neither the LDC nor the OPA will have an entitlement thereto. The OPA will respond to a written request for consent under this Section 6.1(a) within 20 Business Days of receipt thereof.

(b) The LDC hereby transfers and assigns to, or to the extent transfer or assignment is not permitted, holds in trust for, the OPA such OPA Environmental Attributes, and the OPA thereafter will own all rights, title, and interest in and to all such OPA Environmental Attributes.

(c) The LDC will, and each Participant Agreement will provide that the Participant will, from time to time, upon written direction of the OPA, take all such actions and do all such things necessary to effect the transfer and assignment to, or holding in trust for, the OPA, all rights, title, and interest in all such OPA Environmental Attributes.

(d) The LDC will, and each Participant Agreement will provide that the Participant will, from time to time, upon written direction from the OPA, take all such actions and do all such things necessary to certify, obtain, qualify, and register with the relevant authorities or agencies such OPA Environmental Attributes that are created and allocated or credited pursuant to applicable Laws and Regulations from time to time for the purposes of transferring such OPA Environmental

Attributes to the OPA in accordance with this Article 6. The LDC will, and each Participant Agreement will provide that the Participant will, be entitled to reimbursement of the cost of complying with a direction under this Section 6.1(d), provided that the OPA or the LDC, as the case may be, acting reasonably, has approved such cost in writing prior to the cost being incurred by the LDC or the Participant, respectively.

ARTICLE 7
GOOD GOVERNANCE

7.1 Audit Rights and Record Keeping

(a) For a period of seven (7) years or such other period of time specified by Laws and Regulations, where applicable, the LDC will, for purposes of confirming that the LDC has performed its obligations in accordance with this Master Agreement keep complete and accurate books, accounts, and records and all other data required for the purpose of proper administration, monitoring and verification of this Agreement and all of the Registered Initiatives, including records of its revenue received and expenses incurred and paid in connection with each Registered Initiative, all Applications, Participant Agreements, work orders, reports and supporting documents, invoices, receipts, other vouchers and all information received from Participants related to a Registered Initiative.

(b) The LDC will on reasonable notice from the OPA, at any time during normal business hours: (i) permit the OPA or its designate to examine and audit and take copies of such documents and make extracts of the same; and (ii) use Commercially Reasonable Efforts to make available to the OPA or its designate LDC personnel and the personnel of the LDC Other Service Providers involved in the performance of this Master Agreement as reasonably requested by the OPA for purposes of Section 7.1(a).

(c) In conducting an audit pursuant to Section 7.1(a) the OPA shall:

(i) not unreasonably interfere with the operations of the LDC; and

(ii) provide copies of and review and discuss with the LDC the results and findings of any audit conducted hereunder prior to the finalization thereof, and the LDC may prepare and submit a response to such results and findings within fifteen (15) days of receipt thereof from the OPA for consideration and consultation by the OPA prior to finalizing the audit.

(d) Without limiting any other remedies of a Party hereunder, if an audit conducted and finalized pursuant to Section 7.1(a) discloses that there has been an overpayment or underpayment by the OPA or a misappropriation or misuse of funds by the LDC, the amount of the overpayment, underpayment, misappropriation or misuse will be payable or repayable to the OPA or to the LDC, as the case may be, promptly following such disclosure. The cost of an audit will be an expense of the OPA; provided, however that if the result of such audit indicates a material misappropriation or misuse of funds paid by the OPA to the LDC, then, the OPA may demand immediate repayment of, or may set-off or deduct from any subsequent payment, any such misappropriation or misuse as determined by such audit and the LDC will pay the entire reasonable cost of such audit. Without limitation of the foregoing, if such audit reveals a misuse of Program Administration Budget funds that is not material, the OPA may elect to disqualify such amounts as LDC Eligible Program Administration Expenses and will notify the LDC of such election.

7.2 Quality Assurance Inspections

(a) The LDC will on at least five (5) Business Days' prior notice, during normal business hours, but no more frequently than once a calendar year in respect of any Registered Initiative or the provisions, collectively, in the body of the Master Agreement, provide reasonable access to the OPA or its designate to its premises for the purpose of performing an inspection or technical audit to confirm that the LDC has performed its obligations in respect of such Registered Initiative in accordance with this Master Agreement and/or for purposes of implementing the OPA EM&V Protocols. The LDC will notify the OPA ahead of time of, and the OPA will comply with, any and all security and safety measures currently prescribed by the LDC at the LDC's premises at the time of such audit.

(b) In conducting an inspection or audit under Section 7.2(a) that reveals any failure by the LDC to perform its obligations hereunder, the OPA will provide copies of and review and discuss with the LDC the results and findings of any inspection or audit conducted hereunder prior to the finalization thereof, and the LDC may prepare and submit a response to such results and findings within fifteen (15) days of receipt thereof from the OPA.

(c) Any inspection or audit under Section 7.2(a) by or on behalf of the OPA shall not relieve the LDC of any of its obligations to comply with the terms of this Master Agreement. In no event will any inspection or audit by the OPA hereunder be an acknowledgement by the OPA that there has been or will be compliance with this Master Agreement.

7.3 Program Administration Spending and Monitoring

(a) If at any time after the date eighteen (18) months after the Effective Date, in either Party's opinion, acting reasonably and in good faith, any report, invoice, CDM Annual Report, audit, review or other evidence indicates that: (i) the amount of the Program Administration Budget spent by the LDC is materially higher or lower than the expected amount of spending up to such time; (ii) the verified or unverified Peak Demand Savings or Electricity Savings of the LDC achieved up to such time in respect of a Registered CDM Program are materially lower than the Savings Milestones expected to be achieved up to such time (as compared to the Savings Milestones as at the Effective Date or as otherwise determined by a Party, acting reasonably); or (iii) the Savings Milestones, Peak Demand Savings

Target or Electricity Savings Target have changed from the Savings Milestones, Peak Demand Savings Target or Electricity Savings Target as at the Effective Date or the LDC's CDM Target has changed from the LDC's CDM Target as at the Effective Date, then within thirty (30) days of receipt of notice from either Party, a Senior Conference will be convened.

(b) Either Party may table at such Senior Conference, and the Parties will act reasonably and in good faith to achieve agreement in respect of, a plan to normalize the spending of the Program Administration Budget, to achieve the Peak Demand Savings Target or Electricity Savings Target or to remedy the shortfalls in achieving the Savings Milestones, as applicable (a "**Remediation Plan**"). A Remediation Plan may propose the reallocation of the Program Administration Budgets between Registered CDM Programs, modifications to the delivery or design of any Initiative or CDM Program, the development of new Initiatives or CDM Programs, provided that any obligation on the OPA to implement or undertake any Remediation Plan will be at the sole discretion of the OPA. The LDC will provide any information specified by the OPA for the purposes of evaluating the LDC's proposed Remediation Plan or to prepare or modify its own Remediation Plan. The OPA will provide any reasonably available information regarding the LDC's implementation of each Registered Initiative in question, as requested by the LDC. If during such Senior Conference the Parties are unable to agree upon a Remediation Plan or any other solution to the subject matter of the Senior Conference, then the OPA may terminate such Registered CDM Program pursuant to Section 10.6 or 10.7 (without the application of Section 10.6(c) or 10.7(c), as applicable). In the event of such termination, the OPA will provide an explanation as to the reason therefor.

(c) Notwithstanding the provisions of Section 7.3(a), if any CDM Program becomes a Registered CDM Program pursuant to Section 3.2 or Section 3.3(a)(i) more than six (6) months after such Initiative or CDM Program became available for Registration, the OPA may require the LDC to promptly participate in a Senior Conference pursuant to Section 7.3(a).

ARTICLE 8
REPORTING REQUIREMENTS

8.1 LDC Reporting Requirements

(a) The LDC will provide to the OPA:

(i) on or before February 28 of each year commencing on February 28, 2012 and ending on February 28, 2015, an accounting of the LDC Eligible Program Administration Expenses incurred by the LDC for the preceding calendar year in respect of each Registered Initiative with expenses broken down as specified in Schedule A-6;

(ii) the data and reports as specified in each Initiative Schedule for each Registered CDM Program; and

(iii) any information relating to this Agreement reasonably requested by the OPA that is available to the LDC using Commercially Reasonable Efforts.

(b) The LDC will provide to the OPA (if it is not explicitly addressed in its CDM Strategy or CDM Annual Report) within 30 days of it becoming Registered for a CDM Program, its Savings Milestones for such Registered CDM Program.

8.2 Reporting Requirements

(a) Provided that the LDC has complied with its obligations pursuant to Sections 2.5, 8.1 and 9.1, the OPA, based upon the best information then available to it, will provide to the LDC:

(i) if requested by the LDC, by the end of each calendar quarter the unverified Electricity Savings and Peak Demand Savings estimates (in kWh and kW) of the LDC arising from each Registered Initiative for the immediately preceding calendar quarter;

(ii) by August 1 of the second year of the Term and by August 1 of each of the three years thereafter, drafts of the report contemplated by Section 8.2(a)(iii) to the extent available; and

(iii) by September 1 of the second year of the Term, and by September 1 of each of the three years thereafter, a report listing the estimated Electricity Savings and Peak Demand Savings of the LDC arising from each Registered Initiative during the immediately preceding calendar year reported by rate class.

ARTICLE 9
EVALUATION, MEASUREMENT AND VERIFICATION

9.1 Evaluation, Measurement and Verification

(a) Each CDM Program and Initiative will be subject to the OPA EM&V Protocols. The OPA EM&V Protocols will include evaluations of:

(i) the effectiveness of each CDM Program in meeting its objectives and achieving Electricity Savings and Peak Demand Savings;

(ii) the effectiveness of each Initiative, including, if practicable, the components of each such Initiative, in meeting its objectives and achieving Electricity Savings and Peak Demand Savings; and

(iii) the actual Electricity Savings and Peak Demand Savings of the LDC arising from each Registered Initiative.

(b) In furtherance of the OPA EM&V Protocols, the LDC will cooperate with the OPA and will collect information as may be reasonably prescribed by the OPA in respect of each Registered Initiative and make available such information to the OPA in the form and with the frequency as may be reasonably prescribed by the OPA. Without limitation of the generality of the foregoing, the LDC will:

(i) provide the OPA at its request the following information:

(A) for all Participants, name, account number, address and phone number;

(B) for all Participants, rate class; and

(C) for a sampling of Participants sufficient for the OPA to evaluate a Registered Initiative pursuant to the OPA EM&V Protocols, historical consumption data as is reasonably required by the OPA to establish a baseline of electricity consumption for such Participants provided that such historical consumption data is reasonably available;

(ii) collaborate with the OPA to establish a baseline of electricity consumption for non-Participants or other representative control group sufficient for the OPA to evaluate a Registered Initiative pursuant to the OPA EM&V Protocols, including by using Commercially Reasonable Efforts to provide access to historical consumption data in anonymized form for such representative control group; and

(iii) for three (3) years from the date of collection, keep proper and accurate records of such information prescribed by the OPA in this Section 9.1 and make available such records and applicable personnel in accordance with the provisions of Section 7.1; and

(iv) make available all books, accounts and other records contemplated by Section 7.1 in accordance with the provisions of Section 7.1.

(c) The LDC will appoint a knowledgeable individual who will cooperate with the OPA and participate in the conduct of the OPA EM&V Protocols as reasonably required by the OPA.

(d) Subject to the provisions of Article 12, the OPA may publish the results arising from the OPA EM&V Protocols from time to time.

(e) The OPA will issue the OPA EM&V Protocols by March 31, 2011 and will consult with the EDA from time to time with respect to the determination of Peak Demand Savings and Electricity Savings for purposes of the OPA EM&V Protocols.

ARTICLE 10
TERM, DEFAULT AND REMEDIES

10.1 Term

(a) This Master Agreement will commence on the Effective Date and terminate on December 31, 2014 unless terminated prior thereto pursuant to the terms hereof (the "**Term**"). For certainty, no Participant Incentives will be paid by the OPA for Projects completed after December 31, 2014, unless the OPA has amended the Initiative Schedule and any corresponding Participant Agreement to extend the term to December 31, 2015 in which case no Participant Incentive will be paid by the OPA for Projects completed after December 31, 2015. Accordingly, the LDC will not enter into any Participant Agreement that may require that a Participant Incentive be paid for a Project completed after December 31, 2014 (or December 31, 2015 in the case of an Initiative Schedule and any corresponding Participant Agreement that has been extended to December 31, 2015), unless the LDC will pay such Participant Incentive from its own funds.

(b) An Initiative Schedule may set out the term of such Initiative and any terms and conditions relating to the termination or extension of such Initiative (the "**Initiative Term**"). If the Initiative Term of an Initiative Schedule or, subject to Section 10.1(a), the term of a form of Participant Agreement, extends past the termination or expiration of the Term, then such Initiative Schedule or Participant Agreement, including the terms and conditions of this Master Agreement applicable to such Initiative Schedule or Participant Agreement, will survive the termination or expiration of the Term.

(c) Unless the OPA notifies the LDC otherwise, a notice pursuant to Section 10.6(a) will be deemed to have been given effective as of June 30, 2014 with a Cessation Period ending on December 31, 2014, and the provisions of Sections 10.6(a) and 10.6(b) will become effective as of June 30, 2014, *mutatis mutandis*.

10.2 Events of Default by the LDC

Each of the following will constitute an event of default by the LDC (each, an "**LDC Event of Default**"):

(a) The LDC fails to make any payment required under this Master Agreement or any Participant Agreement when due and such failure is not remedied within the Cure Period.

(b) The LDC fails to perform or observe any of its obligations under this Master Agreement in any material respect (except to the extent constituting a separate LDC Event of Default) and such failure is not remedied within the Cure Period.

(c) The LDC is in breach of any obligation under Article 5 and such breach is not remedied within ten (10) days from the date the OPA provides notice to the LDC of such breach.

(d) The LDC is in breach of its OEB licence in a manner that materially adversely affects the LDC's ability to perform its obligations under this Master Agreement and such breach is not remedied within the Cure Period.

(e) By agreement, decree, judgment or order of a Governmental Authority, the LDC agrees to be treated as or is adjudicated bankrupt or insolvent or any substantial part of the LDC's property is sequestered or subject to the appointment of any third party and such agreement, decree, judgment, order or appointment continues in effect unrevoked, undischarged and unstayed for a period of thirty (30) days after the entry or implementation thereof.

(f) The LDC dissolves, winds up or liquidates, or makes an assignment for the benefit of its creditors generally under any Insolvency Legislation, or consents to the appointment of a receiver, manager, receiver-manager, monitor, trustee in bankruptcy, or liquidator for all or part of its property or files a petition or proposal to declare bankruptcy or to reorganize pursuant to the provision of any Insolvency Legislation.

(g) The LDC makes a material misrepresentation, misstatement or omission in any report, invoice or any other information submitted by the LDC to the OPA and such misrepresentation, misstatement or omission is not made true or correct or otherwise remedied within the Cure Period; provided, however, if such misrepresentation, misstatement or omission is in relation to the LDC's obligations under Section 5.6, any such misrepresentation, misstatement or omission, whether material or not, will not be subject to the Cure Period but must be corrected within thirty (30) days from the date the OPA provides notice to the LDC of such breach.

(h) The LDC misappropriates, or uses in a manner not expressly provided herein, any funding provided to the LDC by the OPA hereunder, and such misappropriation or misuse is not remedied within ten (10) days from the date the OPA provides notice to the LDC of such breach. For clarity, any decrease of a Program Administration Budget in accordance with Section 4.3 to a level insufficient to commercially reasonably deliver a Registered CDM Program and its corresponding Registered Initiatives in accordance with this Agreement and any Schedule hereunder is a misappropriation in accordance with this Section 10.2(h).

(i) The LDC is in breach of any obligation under Article 12 and such breach is not remedied within five (5) days from the date the OPA provides notice to the LDC of such breach.

10.3 Remedies of the OPA

(a) If any LDC Event of Default occurs and is continuing, upon written notice to the LDC, the OPA may, in addition to and not in substitution for any other remedies available at law or equity:

(i) by declaring a termination date not later than thirty (30) days from the date of such notice terminate this Master Agreement;

(ii) by declaring a termination date not later than thirty (30) days from the date of such notice terminate the LDC's ability to participate in any Registered CDM Program or Registered Initiative by declaring that the Initiative Schedule(s) in respect of which the LDC Event of Default is continuing is terminated;

(iii) suspend payment of any amounts owing hereunder to the LDC until such time as the LDC Event of Default has been remedied to the satisfaction of the OPA, acting reasonably;

(iv) set off any amounts owing to the LDC hereunder against any amounts then or thereafter owing to the OPA by the LDC;

(v) terminate the Sublicence if the LDC Event of Default arises in relation to the LDC's obligations under Section 5.6;

(vi) only in connection with an LDC Event of Default arising in respect of the LDC's obligations related to a Program Administration Budget, prescribe any additional conditions on the use by the LDC of the Program Administration Budget, including (A) requiring the LDC to implement more stringent quality control measures, (B) pre-authorization by the OPA of the payment by the LDC of amounts that the LDC intends to categorize as LDC Eligible Program Administration Expenses, (C) reduction of amounts payable in respect of expenses that the LDC has previously characterized as LDC Eligible Program Administration Expenses and (D) disqualification from future spending of any LDC Eligible Program Administration Expenses; or

(vii) demand the prompt repayment of the Program Administration Budget held by the LDC and not yet spent on, or incurred and payable but not yet paid in respect of, LDC Eligible Program Administration Expenses.

(b) If the OPA exercises any of its remedies identified in Section 10.3(a)(i) or Section 10.3(a)(ii), then with respect to the Registered CDM Program or Registered Initiatives terminated and without limitation of the OPA's remedy pursuant to Section 10.3(a)(iv):

(i) the LDC will immediately stop marketing, soliciting, accepting Applications, entering into Participant Agreements or otherwise increasing any Person's obligations or liabilities in respect of such Registered Initiatives;

(ii) the OPA will, subject to its receipt of the LDC's invoices in accordance with Section 4.7:

(A) pay to the LDC the amounts the LDC has spent, or that it has incurred and that are payable, under this Master Agreement as LDC Eligible Program Administration Expenses in respect of such Registered Initiatives up to and including the date of termination of such Initiative, including, subject to Section 4.7(g), payment of invoices in respect of such incurred amounts where the invoices are dated after the date of such termination;

(B) pay to the LDC any Participant Based Funding Amounts or Capability Building Funding Amounts in respect of such Registered Initiatives that were payable by the OPA to the LDC up to and including the date of termination of such Initiative but that remain unpaid to the date of termination of such Initiative; and

(C) for so long as the LDC continues to perform its obligations pursuant to Section 2.8 and to provide invoices in accordance with Section 4.7 in respect thereof, pay to the LDC Participant Incentives for Participant Agreements in good standing duly entered into and in effect prior to or on the date of termination of such Initiative; and

(iii) if such termination results in the termination of a Registered CDM Program in its entirety:

(A) subject to Section 4.11(c), the LDC will be entitled to retain from any remaining amounts held by the LDC as part of the Program Administration Budget for such Registered CDM Program the Post-Termination Administration Costs in respect of such Registered CDM Program;

(B) the OPA will not be obligated to continue to make any payments in respect of such Registered CDM Program other than those provided in Section 10.3(b)(ii)(C); and

(C) the Parties will true-up the Program Administration Budget for such Registered CDM Program as at the date of such termination such that: (x) any remaining amounts held by the LDC as part of the Program Administration Budget for such Registered CDM Program will be promptly repaid to the OPA; or (y) other than as provided in Section 10.3(b)(ii)(C), instead of making any payments contemplated by this Section 10.3(b) the OPA may net the amount of any such payments against any such remaining amounts of the Program Administration Budget held by the LDC. For certainty, the operation of this Section 10.3(b)(iii) will not result in the OPA paying to the LDC any amount in excess of the Program Administration Budget for such Registered CDM Program nor result in the LDC repaying to the OPA any amount duly spent or incurred in respect of LDC Eligible Program Administration Expenses in respect of such Registered CDM Program.

10.4 Events of Default by the OPA

Each of the following will constitute an Event of Default by the OPA (each, an "**OPA Event of Default**"):

(a) The OPA fails to make any payment required under this Master Agreement when due and such failure is not remedied within the Cure Period.

(b) The OPA is in breach of its OEB licence in a manner that materially adversely affects the OPA's ability to perform its obligations under this Master Agreement and such breach is not remedied within the Cure Period.

(c) The OPA fails to perform or observe any of its material obligations under this Master Agreement in any material respect (except to the extent constituting a separate OPA Event of Default) and such failure is not remedied within the Cure Period.

(d) The OPA is in breach of any obligation under Article 5 and such breach is not remedied within ten (10) days from the date the LDC provides notice to the OPA of such breach.

(e) The OPA is in breach of any obligation under Article 12 and such breach is not remedied within five (5) days from the date the LDC provides notice to the OPA of such breach.

10.5 Termination by the LDC for Default

(a) If any OPA Event of Default occurs and is continuing, then, upon written notice to the OPA, the LDC may by declaring a termination date not later than thirty (30) days from the date of such notice:

(i) terminate this Master Agreement; or

(ii) terminate the Initiative Schedule for any Registered Initiative pursuant to which the OPA Event of Default occurred**.**

(b) Subject to the provisions of Section 10.3, upon any such termination:

(i) the OPA will, subject to its receipt of the LDC's invoices in accordance with Section 4.7:

(A) pay to the LDC the amounts the LDC has spent, or that it has incurred and that are payable, under this Master Agreement as LDC Eligible Program Administration Expenses in respect of such Registered Initiative up to and including the date of termination of such Initiative, including, subject to Section 4.7(g), payment of invoices in respect of such incurred amounts where the invoices are dated after the date of such termination;

(B) pay to the LDC any Participant Based Funding Amounts or Capability Building Funding Amounts in respect of such Registered Initiative that were payable by the OPA to the LDC up to and including the date of termination of such Initiative but that remain unpaid to the date of termination of such Initiative; and

(C) for so long as the LDC continues to perform its obligations pursuant to Section 2.8 and to provide invoices in accordance with Section 4.7 in respect thereof, pay to the LDC Participant Incentives for Participant Agreements in good standing duly entered into and in effect prior to or on the date of termination of such Initiative.

(c) If any OPA Event of Default set out in Sections 10.4(a), 10.4(b) or 10.4(c) has occurred and has been continuing for a period of one hundred and twenty (120) days, then, upon written notice to the OPA, the LDC may immediately:

(i) terminate this Master Agreement; or

(ii) terminate any Initiative Schedule pursuant to which the OPA Event of Default occurred**,**

and the provisions of Section 10.7(b) will become effective, *mutatis mutandis*, as if the OPA had terminated the Registered CDM Programs or Initiative Schedules listed in such notice of termination.

10.6 Cessation of Registered CDM Program or Registered Initiative

(a) Upon receipt by the LDC of notice from the OPA requesting that the Parties commence the cessation of a Registered CDM Program or Registered Initiative, the LDC will work in good faith with and assist the OPA to the extent required to cease providing the Registered CDM Program or Registered Initiative within a period ending no earlier than six months from the date of receipt of such notice (the "**Cessation Period**"), which will include, at a minimum:

(i) the development of a plan for the cessation of the Registered CDM Program or Registered Initiative that sets out, at a minimum (the "**Cessation Plan**"):

(A) each Party's responsibilities for the performance of the obligations set out in the plan;

(B) the plan and time line for the cessation of the Registered CDM Program;

(C) the steps to be taken for minimizing any impact to Participants caused by the cessation of the Registered CDM Program;

(D) details relating to any incremental reporting to be provided during the Cessation Period; and

(ii) the performance of the obligations of the each of the Parties set out in the Cessation Plan.

(b) During the Cessation Period, the LDC will take steps to wind down in an orderly manner the marketing, solicitation, and acceptance of Applications and the entering into of Participant Agreements, and will take any other reasonable steps to avoid increasing any Person's obligations or liabilities in respect of such Registered CDM Program or Registered Initiative following the Cessation Period. On the last day of the Cessation Period:

(i) the Registered CDM Program or Registered Initiative shall terminate; and

(ii) subject to Section **Error! Reference source not found.**, the provisions of Section 10.3(b)(ii) or 10.3(b)(iii), as applicable, will apply *mutatis mutandis*.

(c) If the Registered CDM Program or Registered Initiative is terminated under this Section 10.6, except in the case where the Registered CDM Program or Registered Initiative is required to be terminated pursuant to Laws and Regulations, if the LDC still must achieve during the remainder of the Term its Electricity Savings Target and Peak Demand Savings Target, the OPA will use Commercially Reasonable Efforts to work with the LDC to introduce a replacement CDM Program or Initiative.

10.7 Immediate Termination by the OPA of Registered CDM Program or Registered Initiative

(a) The OPA may, at its option, terminate any Registered CDM Program or Registered Initiative with immediate effect by providing written notice to the LDC.

(b) If the OPA terminates any Registered CDM Program or any Initiative Schedule for a Registered Initiative pursuant to Section 10.7(a), then with respect to the Registered Initiatives terminated:

(i) the OPA will, subject to its receipt of the LDC's invoices in accordance with Section 4.7:

(A) pay to the LDC the amounts the LDC has spent, or that it has incurred and that are payable, under this Master Agreement as LDC Eligible Program Administration Expenses in respect of such Registered Initiatives up to and including the date of termination of such Initiative, including, subject to Section 4.7(g), payment of invoices in respect of such incurred amounts where the invoices are dated after the date of such termination;

(B) pay to the LDC any Participant Based Funding Amounts or Capability Building Funding Amounts in respect of such Registered Initiatives that were payable by the OPA to the LDC up to and including the date of termination of such Initiative but that remain unpaid to the date of termination of such Initiative; and

(C) for so long as the LDC continues to perform its obligations pursuant to Section 2.8 and to provide invoices in accordance with Section 4.7 in respect thereof, pay to the LDC Participant Incentives for Participant Agreements in good standing duly entered into and in effect prior to or on the date of termination of such Initiative; and

(ii) if such termination results in the termination of a Registered CDM Program in its entirety:

(A) subject to Section 4.11(c), the LDC will be entitled to retain from any remaining amounts held by the LDC as part of the Program Administration Budget for such Registered CDM Program the Post-Termination Administration Costs in respect of such Registered CDM Program;

(B) the OPA will pay to the LDC the Immediate Wind-down Costs in respect of such Registered CDM Program;

(C) the OPA will not be obligated to continue to make any payments in respect of such Registered CDM Program other than those provided in Section 10.7(b)(i)(C); and

(D) the Parties will true-up the Program Administration Budget for such Registered CDM Program as at the date of such termination such that: (x) any remaining amounts held by the LDC as part of the Program Administration Budget for such Registered CDM Program will be promptly repaid to the OPA; or (y) other than as provided in Section 10.7(b)(i)(C), instead of making any payments contemplated by this Section 10.3(b) the OPA may net the amount of any such payments against any such remaining amounts of the Program Administration Budget held by the LDC. For certainty, the operation of this Section 10.7(b)(ii) will not result in the OPA paying to the LDC any amount in excess of the Program Administration Budget for such Registered CDM Program nor result in the LDC repaying to the OPA any amount duly spent or incurred in respect of LDC Eligible Program Administration Expenses in respect of such Registered CDM Program.

(c) If the Registered CDM Program or Registered Initiative is terminated under this Section 10.7, except in the case where the Registered CDM Program or Registered Initiative is required to be terminated pursuant to Laws and Regulations, if the LDC still must achieve during the remainder of the Term its Electricity Savings Target and Peak Demand Savings Target, the OPA will use Commercially Reasonable Efforts to work with the LDC to introduce a replacement CDM Program or Initiative.

10.8 Survival

(a) Neither the expiration of the Term nor the earlier termination of this Master Agreement will release either of the Parties from any obligation or liability incurred prior to such expiration or termination.

(b) The provisions of this Master Agreement requiring performance or fulfilment after the expiration or earlier termination of this Master Agreement, including Section 2.8(c), Section 2.8(d), Section 4.7(i), Section 4.9, Section 4.10, Article 5, Article 6, Section 7.1, Section 8.2(a), Section 9.1, Article 11, Article 12, Article 13, Section 14.4 and this Section 10.8, such other provisions as are necessary for the interpretation thereof and any other provisions hereof, the nature and intent of which is to survive termination or expiration of this Master Agreement, will survive the expiration or earlier termination of this Master Agreement.

(c) For certainty, the continued existence of materials distributed to third parties during the Term that bear the OPA Marks or the Ministry Marks will not constitute infringement of the other Party's Intellectual Property Rights, provided that the appearance of the OPA Marks or the Ministry Marks, as applicable, complies with the applicable Marketing Standards and licence requirements and restrictions set forth in Article 5.

ARTICLE 11
LIMITATION OF LIABILITY AND INDEMNIFICATION

11.1 No Warranty

Except as specifically set forth or referenced in this Master Agreement, there are no representations, warranties, or conditions of either Party, express, implied, statutory or otherwise, regarding any matter. Without limiting the generality of the foregoing, the LDC acknowledges that its participation in any CDM Program hereunder is based on its own assessment of such CDM Program and the Initiatives comprising it and not on any reliance on anticipated or projected results, and that such participation may not result in the achievement of any Electricity Savings, Peak Demand Savings or the LDC’s OEB-approved CDM targets, each of which is expressly disclaimed by the LDC.

11.2 Exclusion of Certain Damages

Notwithstanding anything contained herein to the contrary:

(a) in no event will a Party be entitled to recover from the other Party for any liabilities, damages, obligations, payments, losses, costs, or expenses under this Master Agreement or in relation to this Master Agreement:

(i) any amount in excess of the actual compensatory direct damages, court costs and reasonable lawyers' and other advisor fees suffered or incurred by such Party; or

(ii) damages (whether direct or indirect, consequential or otherwise) for (x) loss of profit, or (y) diminution of value or loss of use of any property;

(b) neither Party will be liable to the other Party for any special, indirect, incidental, punitive, exemplary or consequential damages, which may arise under or in relation to this Master Agreement, regardless of whether such liability arises under contract, tort or any other legal theory;

provided, however:

(A) a Party will be entitled to recover from the other Party the types of damages described in Sections 11.2(a)(ii) and 11.2(b) where such damages arise in respect of a breach by a Party of its obligations contained in Article 12; and

(B) Sections 11.2(a)(ii) and 11.2(b) will not limit the indemnity provided by an Indemnifying Party pursuant to Section 11.3 or Section 11.4 for damages suffered by a third party and claimed against an Indemnified Party.

11.3 Indemnification by the LDC

The LDC (the "**LDC Indemnifying Party**") will be liable for and will indemnify, defend and hold the OPA, the Government of Ontario, the members of the Government of Ontario's Executive Council and their respective Affiliates, and each of the foregoing Person's respective directors, officers, employees, shareholders, advisors, and agents (including contractors and their employees and which, for greater certainty, does not include other Local Distribution Companies) (in this context, collectively, the "**OPA Indemnified Party**") harmless from and against any and all claims, demands, suits, losses, damages, liabilities, penalties, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest on, any and all actions, suits, proceedings for personal injury (including death) or property damage, assessments, judgments, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each, an "**Indemnifiable Loss**"), asserted by a third party against or suffered by the OPA Indemnified Party relating to, in connection with, resulting from, or arising out of (i) the negligence or wilful misconduct of the LDC Indemnifying Party or (ii) the breach by the LDC of any provision of this Master Agreement; except to the extent that such Indemnifiable Loss is attributable to the negligence or wilful misconduct of the OPA Indemnified Party or any Person for whom the OPA is responsible hereunder or at law or the breach by the OPA of any provision of this Master Agreement. For greater certainty, in the event of contributory negligence or breach of the OPA Indemnified Party, then such OPA Indemnified Party will not be indemnified hereunder in the proportion that the OPA Indemnified Party's negligence or breach contributed to any Indemnifiable Loss.

11.4 Indemnification by the OPA

The OPA (the "**OPA Indemnifying Party**") will be liable for and will indemnify, defend and hold the LDC, its Affiliates, and each of the foregoing Person's respective directors, officers, employees, shareholders, advisors, and agents (including contractors and their employees and which, for greater certainty, does not include other Local Distribution Companies) (in this context, collectively, the "**LDC Indemnified Party**") harmless from and against any and all Indemnifiable Losses, asserted by a third party against or suffered by the LDC Indemnified Party relating to, in connection with, resulting from, or arising out of (i) any activity conducted by the LDC in carrying out its obligations with respect to the transfer, assignment, holding, certification, procurement, qualification or registration of the OPA Environmental Attributes required by Article 6, (ii) the negligence or wilful misconduct of the OPA Indemnifying Party or (iii) the breach by the OPA of any provision of this Master Agreement, except to the extent that such Indemnifiable Loss is attributable to the negligence or wilful misconduct of the LDC Indemnified Party or any Person for whom the LDC is responsible hereunder or at law or the breach by the LDC of any of the terms of this Master Agreement. For greater certainty, in the event of contributory negligence or breach of the LDC Indemnified Party, then such LDC Indemnified Party will not be indemnified hereunder in the proportion that the LDC Indemnified Party's negligence or breach contributed to any Indemnifiable Loss. For certainty, the provisions of this Section 11.4 do not apply to any Environmental Attributes retained by a Participant.

11.5 Defence of Claims

(a) Promptly after receipt by the Indemnified Party of any claim or notice of the commencement of any action, administrative or legal proceeding, or investigation as to which an indemnity provided for in Section 11.3 or Section 11.4 may apply, the Indemnified Party will notify the Indemnifying Party in writing of such fact. The Indemnifying Party will assume the defence thereof with counsel designated by the Indemnifying Party and satisfactory to the affected Indemnified Party, acting reasonably; provided, however, that if the defendants in any such action include both the Indemnified Party and the Indemnifying Party and the Indemnified Party has reasonably concluded that there may be legal defences available to it which are different from or additional to, or inconsistent with, those available to the Indemnifying Party, the Indemnified Party will have the right to select separate counsel satisfactory to the Indemnifying Party acting reasonably (at no additional cost to the Indemnified Party) to participate in the defence of such action on behalf of the Indemnified Party. The Indemnifying Party will promptly confirm that it is assuming the defence of the Indemnified Party by providing written notice to the Indemnified Party. Such notice will be provided no later than five (5) days prior to the deadline for responding to any claim relating to any Indemnifiable Loss.

(b) Should any Indemnified Party be entitled to indemnification under Section 11.3 or Section 11.4, and the Indemnifying Party fails to assume the defence of such claim (which failure will be assumed if the Indemnifying Party fails to provide the notice prescribed by Section 11.5(a)), the Indemnified Party will, at the expense of the Indemnifying Party, contest (or, with the prior written consent of the Indemnifying Party, acting reasonably, settle) such claim, provided that no such contest need be made and settlement or full payment of any such claim may be made without consent of the Indemnifying Party (with the Indemnifying Party remaining obligated to indemnify the Indemnified Party under Section 11.3 or Section 11.4, as the case may be, if, in the written opinion of an independent third party counsel chosen by the Parties, such claim is meritorious. If the Indemnifying Party is obligated to indemnify any Indemnified Party under Section 11.3 or Section 11.4, the amount owing to the Indemnified Party will be the amount of such Indemnified Party's actual out-of-pocket loss net of any insurance proceeds received or other recovery.

ARTICLE 12
CONFIDENTIALITY AND PRIVACY

12.1 Confidentiality Covenant

(a) Each Party will, in its capacity as a Receiving Party:

(i) not use or reproduce Confidential Information of the Disclosing Party for any purpose, other than as and to the extent expressly permitted under this Master Agreement or as may be reasonably necessary for the exercise of its rights or the performance of its obligations set out in this Master Agreement;

(ii) not disclose, provide access to, transfer or otherwise make available any Confidential Information of the Disclosing Party except as expressly permitted in this Master Agreement; and

(iii) take all measures reasonably required to maintain the confidentiality and security of all Confidential Information of the Disclosing Party that it Handles.

(b) The Receiving Party may disclose Confidential Information of the Disclosing Party:

(i) to a third party that is not a Representative of the Receiving Party if and to the extent required by a Governmental Authority or otherwise as required by Laws and Regulations, provided that such Party must first give the Disclosing Party notice of such compelled disclosure (except where prohibited by Laws and Regulations from doing so) and must use

Commercially Reasonable Efforts to provide the Disclosing Party with an opportunity to take such steps as it desires to challenge or contest such disclosure or seek a protective order. Thereafter, the Receiving Party may disclose the Confidential Information of the Disclosing Party, but only to the extent required by Laws and Regulations and subject to any protective order that applies to such disclosure; and

(ii) to:

(A) its accountants, internal and external auditors and other professional advisors if and to the extent that such Persons need to know such Confidential Information in order to provide the applicable professional advisory services relating to such Party's business;

(B) potential permitted assignees or successors of the Receiving Party if and to the extent that such Persons need to know such Confidential Information in connection with a potential sale, merger, amalgamation or other transaction or transfer involving the business, assets or services provided by the Receiving Party; and

(C) employees of each Party and the OPA Other Service Providers or LDC Other Service Providers, as applicable, if and to the extent that such Persons need to know such Confidential Information to perform their respective obligations under this Master Agreement;

provided that any such Person is aware of the provisions of this Section 12.1 and has entered into a written agreement with the Receiving Party that includes confidentiality obligations in respect of such Confidential Information that are no less stringent than those contained in this Section 12.1.

(c) The OPA may disclose Confidential Information of the LDC to the OEB, IESO, the Minister of Energy and the Environmental Commissioner's Office or their respective successors for Handling by such Persons provided that the OPA has in place with any such Person a written agreement that includes confidentiality obligations in respect of such Confidential Information that are comparable to those contained in this Section 12.1.

(d) Without limiting the foregoing, each Party acknowledges and agrees that:

(i) this Master Agreement and all Confidential Information in the possession or control of the OPA or the LDC are subject to Laws and Regulations that include the access provisions of FIPPA or MFIPPA, and that as a result, third parties may obtain access to each Party's Confidential Information; and

(ii) each Party is responsible for ensuring that its agreements with Other Service Providers contemplate and permit such potential access, and will be fully liable to any such Other Service Provider for any Claim arising out of or relating to such access.

12.2 Privacy

(a) Each Party acknowledges that all Personal Information collected by or accessible to such Party in the course of administering or offering the CDM Programs or otherwise complying with the terms and conditions of this Master Agreement ("**Program Personal Information**") constitutes not only Personal Information of the individual to whom the information relates but also Confidential Information of such Party to which the provisions of Section 12.1 and Privacy Laws apply, except to the extent such provisions are inconsistent with this Section 12.2, which prevails in the case of any such inconsistency. In addition to the obligations set out in Section 12.1(a), and notwithstanding the disclosure rights set out in Section 12.1(b), each Party will:

(i) Handle all Program Personal Information in accordance with all applicable Privacy Laws;

(ii) perform its obligations under this Agreement in a manner that will enable the other Party to comply with Privacy Laws;

(iii) promptly notify the other Party if such Party receives notice from any Governmental Authority alleging that either Party has failed to comply with Privacy Laws in connection with the performance of this Master Agreement, or if such Party otherwise becomes aware that either Party may have failed or may in the future fail to comply with Privacy Laws in connection with the performance of this Master Agreement;

(iv) cooperate and comply with any requests or instructions issued by any privacy or data protection authority, including the Canadian privacy commissioner and any other Governmental Authority applicable to such Party; and

(v) provide reasonable assistance to the other Party in responding to and addressing any complaint relating to the Handling of Program Personal Information.

(b) Without limiting the obligations set forth in Section 12.2(a), the Party responsible for approving an Application of an Eligible Person will, prior to approving such Application, ensure that such Application contains the consents required by Laws and Regulations in order to enable the Party receiving or approving such Application to permit each Party to Handle Program Personal Information in order to (i) deliver the CDM Programs or as contemplated in Sections 5.7 and 9.1 and (ii) otherwise comply with the terms and conditions of this Master Agreement and Laws and Regulations. The Parties acknowledge that such approving Party will have met its obligation if (x) such Application is an Application submitted through the Program Management System that cannot be modified or altered without the consent of the OPA, or (y) if such Eligible Person submitting an Application submits a form of Application or executes a form of Participant Agreement prescribed by the applicable Initiative Schedule, without amendment.

(c) If a Person refuses to provide the consents referred to in Section 12.2(b), each Party will ensure that such Person is not able to submit an Application for, or become a Participant under, the applicable Registered Initiatives for which the Party is responsible for obtaining the consents referred to in Section 12.2(b).

12.3 Injunctive Relief

Each Party acknowledges that any violation of the provisions of this Article 12 may cause irreparable damage or injury to the other Party, the exact amount of which may be impossible to ascertain, and that, for such reason, in addition to any other remedies available to such Party, such Party is entitled to proceed immediately to court in order to obtain, and the other Party will consent to, interim, interlocutory, and final injunctive relief restraining the other Party from breaching, and requiring the other Party to comply with, its obligations under this Article 12, without a requirement that a finding of irreparable harm or other criteria for the awarding of injunctive relief be made. Nothing in this Section 12.3 will be construed to limit the right of a Party to obtain injunctive relief in any other circumstance in which it may be otherwise entitled to such relief.

ARTICLE 13
DISPUTE RESOLUTION

13.1 General

Any controversy, dispute, difference, question or claim (collectively, a "**Dispute**") arising between the Parties in connection with the interpretation, performance, construction or implementation of this Master Agreement that cannot be resolved by a director or manager from each Party within ten (10) Business Days after the Dispute has arisen will be settled in accordance with this Article 13.

13.2 Senior Officers

The aggrieved Party will send the other Party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. Senior officers with authority to bind the Party, as selected by each Party in its discretion, will confer in an effort to resolve the Dispute (a "**Senior Conference**"). If the Dispute cannot be resolved by a Senior Conference within thirty (30) days of the date the Dispute arose or such later date as agreed to by the Parties, the Dispute will be resolved by arbitration in accordance with Sections 13.3, 13.4 and 13.5 below.

13.3 Arbitrators

The Parties will submit any arbitration under this Master Agreement to a single arbitrator agreed upon by both Parties. If the Parties cannot agree upon a single arbitrator within ten (10) days after the Dispute is referred to arbitration, each Party will within ten (10) more days choose one individual who will sit on a three-member arbitration panel. The two arbitrators appointed will name the third arbitrator within ten (10) days or, if they fail to do so within that time period, either Party may make an application to a court of competent jurisdiction for appointment of the third arbitrator. Any arbitrator selected to act under this Master Agreement will be qualified by education, training and experience to pass on the particular question in Dispute and will have no connection to either of the Parties other than acting in previous arbitrations.

13.4 Procedures of Arbitration

The arbitrator or arbitration panel selected pursuant to Section 13.3 (hereinafter referred to as the "**arbitrator**") will not have any current or past business or financial relationships with any Party (except prior to arbitration). The arbitrator will provide each of the Parties an opportunity to be heard and will conduct the arbitration hearing in accordance with the provisions of the Arbitration Act. Unless otherwise agreed by the Parties, the arbitrator will render a decision within ninety (90) days after the end of the arbitration hearing and will notify the Parties in writing of such decision and the reasons therefor. The arbitrator will be authorized only to interpret and apply the provisions of this Master Agreement and will have no power to modify or change this Master Agreement in any manner. The decision of the arbitrator will be conclusive, final and binding upon the Parties. The decision of the arbitrator may be appealed solely on the grounds that the conduct of the arbitrator, or the decision itself, violated the provisions of the Arbitration Act or solely on a question of law as provided for in the Arbitration Act. The Arbitration Act will govern the procedures to apply in the enforcement of any award made. If it is necessary to enforce such award, all costs of enforcement will be payable and paid by the Party against whom such award is enforced. Unless otherwise provided in the arbitral award to the contrary, each Party will bear (and be solely responsible for) its own costs incurred during the arbitration process, and each Party will bear (and be solely responsible for) its equal share of the costs of the arbitrator. Each Party will otherwise be responsible for its own costs incurred during the arbitration process.

13.5 Disclosure/Confidentiality

All proceedings and the making of the award in respect of Section 13.4 will be in private and the Parties will ensure that the conduct of the arbitration and the terms of the award will, subject to registration of the award in any court, be kept confidential unless the Parties otherwise agree; provided, however, that such obligation to maintain confidentiality will not prohibit any Party from complying with Laws and Regulations. All information disclosed, including all statements made and documents produced, in the course of the arbitration will be held in confidence and no Party will rely on, or introduce as evidence in any subsequent proceeding, any admission, view, suggestion, notice, response, discussion or position of either Party or any acceptance of a settlement proposal or recommendation for settlement made during the course of the arbitration, except (i) as required by Laws and Regulations; or (ii) to the extent that disclosure is reasonably necessary for the establishment or protection of a Party's legal rights against a third party or to enforce the award of the arbitrator or to otherwise protect a Party's rights under the arbitration.

13.6 Exclusion

This Article 13 will not apply to an arbitration arising pursuant to Schedule A-4 except as expressly provided in Schedule A-4.

ARTICLE 14
MISCELLANEOUS

14.1 Further Assurances

Each of the Parties will, from time to time, on written request of the other Party, do all such further acts and execute and deliver or cause to be done, executed and delivered all such further things as may be reasonably required in order to fully perform and to more effectively implement the terms of this Master Agreement.

14.2 Severability

The invalidity, unenforceability or illegality of any provision in this Master Agreement as finally determined pursuant to Section 13.4 will not, to the extent permitted by law, affect the validity, enforceability or legality of any other provision of this Master Agreement, which will remain in full force and effect.

14.3 Binding Agreement

This Master Agreement will enure to the benefit of and will be binding on and enforceable by the Parties and, where the context so permits, their respective successors and permitted assigns.

14.4 Independent Legal and Tax Advice

(a) The LDC acknowledges that it has entered into this Agreement willingly with full knowledge of the obligations imposed by the terms hereof. The LDC, by execution hereof, acknowledges that it has been afforded the opportunity to obtain independent legal and other advice and confirms by the execution hereof that it has either done so or waived its right to do so and agrees that this Agreement constitutes a binding legal obligation and that it is estopped from raising any claim on the basis that it has not obtained such advice.

(b) In particular, the LDC acknowledges that it understands the meanings of the provisions of the Participant Agreements or the meanings of the provisions stipulated as mandatory, as applicable, and further acknowledges that the OPA is not providing any legal or tax advice in respect of the Participant Agreements to be entered into by the LDC.

14.5 Third Party Beneficiaries

Except as otherwise set out in this Master Agreement, this Master Agreement will not confer upon any other person except the Parties and their respective successors and permitted assigns, any rights, interests, obligations or remedies under this Master Agreement.

14.6 Assignment

Neither Party may assign this Master Agreement, in whole or in part, without the prior written consent of the other Party, which consent may not be unreasonably withheld.

14.7 Notices

Any notice to be given under this Master Agreement unless expressly provided otherwise herein must be in writing and will be given by facsimile or e-mail or by hand-delivery as provided. Any notice, if sent by facsimile or e-mail, will be deemed to have been received on the Business Day following the day of sending, or if delivered by hand will be deemed to have been received on the Business Day it is delivered to the applicable address noted below. Either Party may, by notice of change of address to the other Party, change its address to which notices are to be sent. Notices and other communications must be addressed as set forth in Schedule A-3.

IN WITNESS WHEREOF, the Parties have entered into this Master Agreement as of the date first written above.

SCHEDULE A-1

DEFINITIONS

In this Master Agreement the following terms shall have the following meanings:

"**Additional Initiative**" means an Initiative applicable to a Registered CDM Program but that is not a Registered Initiative (i) as at the Effective Date or (ii) pursuant to Section 3.2 or Section 3.3(a)(ii).

"**Additional Initiative Notice Period**" has the meaning given to it in Schedule A-4.

"**Additional Initiative Schedule**" means a Schedule setting forth the terms and conditions of: (i) a Registered Initiative, as attached to this Master Agreement in accordance with the provisions of Section 3.2 or Section 3.3(a)(ii); or (ii) an Additional Initiative, as attached to this Master Agreement in accordance with the Change Terms.

"**Affiliate**" has the meaning given to it in the *Business Corporations Act* (Ontario).

"**Applicable Taxes**" has the meaning given to it in Section 4.9(a).

"**Application**" means, in respect of an Initiative, any form of request that must be completed by a Person (as prescribed by the applicable Initiative) in order to participate in such Initiative, including a completed application form.

"**Arbitration Act**" means the *Arbitration Act, 1991* (Ontario).

"**Billing Period**" has the meaning given to it in Section 4.7(e).

"**Billing Report**" has the meaning given to it in Section 4.7(b).

"**body**" means, in respect of this Master Agreement, this Master Agreement excluding the Schedules.

"**Business Day**" means a day, other than a Saturday or Sunday or statutory holiday in the Province of Ontario or any other day on which banking institutions in Toronto, Ontario are not open for the transaction of business.

"**Capability Building Funding Amount**" means, in respect of an Initiative, a funding amount payable to the LDC or a Participant to assist with the implementation of organizational measures that facilitate the delivery of CDM generally or certain CDM Programs specifically, as specified in the Initiative Schedule for such Initiative.

"**CDM**" means electricity conservation and demand management.

"**CDM Annual Report**" means the LDC's "Annual Report" as defined in the CDM Code.

"**CDM Code**" means the Conservation and Demand Management Code for Electricity Distributors, as approved by the OEB.

"**CDM Program**" or "**OPA-Contracted Province-Wide CDM Program**" means a group of Initiatives designed by the OPA pursuant to the Directive and directed at one of the Commercial and Institutional, Industrial, Low-Income or Residential electricity consumer groups, as set forth in Schedule A-2. The specific names of the CDM Programs are set forth in Schedule A-2.

"**CDM Strategy**" means the LDC's "CDM Strategy" as defined in the CDM Code.

"**CDM Target**" has the meaning given to it in the CDM Code.

"**Cessation Period**" has the meaning given to it in Section 10.6(a).

"**Cessation Plan**" has the meaning given to it in Section 10.6(a)(i).

"**Chair of the Working Group**" means is an LDC member of the Working Group who is selected by its members to represent them as the chair of that particular Working Group.

"**Change**" means an amendment, modification or supplement of this Master Agreement (including, for certainty the body of this Master Agreement), of any Schedules hereto, or of any Participant Agreement or Eligibility Criteria, in each case made or proposed other than pursuant to Section 3.1(b).

"**Change Letter Request**" has the meaning given to it in Section 2(a) of Schedule A-4.

"**Change Management Parties**" means the EDA Representative and the OPA.

"**Change Terms**" has the meaning given to it in Section 3.1(a).

"**Claim**" means any actual, threatened or potential civil, criminal, administrative, regulatory, arbitral or investigative demand, allegation, action, suit, investigation or proceeding or any other claim or demand, whether in contract, tort or otherwise.

"**Collaboration Process**" has the meaning given to it in Section 1 of Schedule A-4

"**Commercial and Institutional**" **or** "**C&I**" means, with respect to a particular group composed of electricity consumers, General Service < 50 kW Accounts, General Service > 50kW Accounts or Large Users, and not electricity consumers defined as Residential or Industrial.

"**Commercially Reasonable Efforts**" means all efforts which may be required to enable a Person, directly or indirectly, to satisfy, consummate, complete or achieve a condition, transaction, activity, obligation or undertaking contemplated by this Master Agreement and which do not require such Person to expend any funds or assume liabilities other than expenditures and liabilities which are reasonable in nature and amount in the context of the purpose of, and the Initiatives contemplated by, this Master Agreement.

"**Company Representative**" has the meaning given to it in Section 2.10.

"**Confidential Information**" of a Party means any and all information of such Party or any of its Affiliates, licensors, Participants, customers (including information regarding a customer that is a consumer, wholesaler or generator), and employees or Other Service Providers, and information on Applications, and, in the case of the OPA, Governmental Authorities (the "**Disclosing Party**") that has or will come into the possession or knowledge of the other Party or any of its Affiliates or Other Service Providers (the "**Receiving Party**") in connection with or as a result of entering into this Agreement, including information concerning the Disclosing Party's past, present or future customers, suppliers, technology, or business. Notwithstanding the foregoing, "Confidential Information" does not include information that is:

(a) publicly available when it is received by or becomes known to the Receiving Party or that subsequently becomes publicly available other than through a direct or indirect act or omission of the Receiving Party (but only after it becomes publicly available);

(b) established by evidence to have been already known to the Receiving Party at the time of its disclosure to the Receiving Party and is not known by the Receiving Party to be the subject of an obligation of confidence of any kind;

(c) independently developed by the Receiving Party without any use of or reference to the Confidential Information of the Disclosing Party as established by evidence that would be acceptable to a court of competent jurisdiction; or

(d) received by the Receiving Party in good faith without an obligation of confidence of any kind from a third party who the Receiving Party had no reason to believe was not lawfully in possession of such information free of any obligation of confidence of any kind, but only until the Receiving Party subsequently comes to have reason to believe that such information was subject to an obligation of confidence of any kind when originally received;

provided, however, that, for the purposes of this Master Agreement, all Personal Information concerning any Participant or Person submitting an Application for a Registered Initiative will constitute Confidential Information, whether or not it falls into one of the exceptions set out in clause (a) through (d) of this definition.

"**Cost Efficiency Incentive**" has the meaning given to it in Section 4.6.

"**Cure Period**" means a period of thirty (30) Business Days following delivery by a Party to the other Party of written notice of a failure or breach described in Section 10.2 (in the case of a failure or breach of the LDC) and Section 10.4 (in the case of a failure or breach of the OPA) or such longer period of time as the notifying Party may determine in its sole discretion.

"**Directive**" has the meaning set forth in the recitals hereto.

"**Disabling Code**" means any virus, Trojan horse, worm, logic bomb, drop-dead device, backdoor, shutdown mechanism or similar software, hardware, system or combination of any of the foregoing that is intended or designed to, is operable to, is likely to or has the effect of disabling, deleting, erasing, denying authorized access to, permitting unauthorized access to, repossessing, damaging, destroying, corrupting or otherwise affecting or interfering with the

Program Management System or the normal use of any of OPA's hardware, software or systems or any data or files on or used in conjunction with any of the aforementioned.

"**Disclosing Party**" has the meaning given to it in the definition of Confidential Information.

"**Dispute**" has the meaning given to it in Section 13.1.

"**Distribution Consumer**" means an electricity consumer, whether or not a customer of the LDC, that is directly connected to, or behind the meter of another electricity consumer connected to, the LDC's Distribution System and is in the LDC's service area.

"**Distribution System**" means a system connected to the IESO-Controlled Grid for distributing electricity at voltages of 50 kV or less and includes any structures, equipment or other thing used for that purpose.

"**EDA**" means the Electricity Distributors Association, or such successor thereto as the EDA or such successor may notify the OPA from time to time.

"**EDA Representative**" means the board of directors of the EDA or any individual or committee of the EDA appointed by the board of directors of the EDA for the purpose of this Agreement and of which the OPA has received written notice.

"**Effective Date**" has the meaning first set forth in the preamble to this Master Agreement.

"**Electricity Savings**" means electricity savings determined pursuant to the OPA EM&V Protocols.

"**Electricity Savings Target**" means, for a specific Registered CDM Program, the portion of the LDC's CDM Target that relates specifically to a reduction of electricity consumption that the LDC expects to result from such Registered CDM Program (and, for certainty, not from Board-Approved CDM Programs (as defined in the CDM Code)) as stated in the LDC's CDM Strategy or CDM Annual Report, as such CDM Target may change from time to time in accordance with Laws and Regulations.

"**Eligibility Criteria**" means, in respect of an Initiative, the criteria set out in the applicable Initiative Schedule or exhibits thereto that a Person must meet in order to be eligible to participate in such Initiative.

"**Eligible Costs**" means, in respect of an Initiative, costs and expenses of a Participant payable or reimbursable to such Participant as provided in the applicable Initiative Schedule.

"**Eligible Measures**" means, in respect of an Initiative, Measures as defined or described in the applicable Initiative Schedule.

"**Eligible Person**" means, in respect of an Initiative, a Person that meets the applicable Eligibility Criteria.

"**Environmental Attributes**" means all benefits and entitlements associated with a Measure or a Facility having decreased environmental impacts resulting from the implementation of an Eligible Measure, including:

(a) all rights to any fungible or non-fungible attributes, whether arising from a Facility itself, from the interaction of a Facility with a Distribution System or the IESO-Controlled Grid or because of applicable Laws and Regulations or voluntary programs established by any Governmental Authority;

(b) all rights relating to the nature of the energy source as may be defined and awarded through applicable Laws and Regulations or voluntary programs; and specific Environmental Attributes include ownership rights to any applicable credits, entitlements or other instruments resulting from the interaction of a Facility or an Eligible Measure with a Distribution System or the IESO-Controlled Grid or as specified by applicable Laws and Regulations or voluntary programs;

(c) all rights to quantify and register the foregoing with competent authorities; and

(d) all revenues, entitlements, benefits, and other proceeds arising from or related to the foregoing.

"**Facility**" means the buildings, premises or lands, or part thereof, owned or occupied by an Eligible Person or a Participant and in respect of which such Eligible Person intends to participate, or such Participant is participating, in an Initiative.

"**FIPPA**" means the *Freedom of Information and Protection of Privacy Act* (Ontario).

"**Funding Amount**" has the meaning given to it in Section 4.7(e).

"**General Service < 50 kW Account**" has the meaning given to such term in the annual Yearbook of Electricity Distributors.

"**General Service > 50 kW Account**" has the meaning given to such term in the annual Yearbook of Electricity Distributors.

"**Good Industry Practice**" means, in respect of any aspect of any Eligible Measure, care and disposal of materials, or other actions or obligations contemplated in this Master Agreement or an Initiative Schedule, in each case, that have been or ought to have been performed by a Person, and subject always to Laws and Regulations, the exercise of the degree of skill, diligence, prudence and foresight and practice which could reasonably and ordinarily be expected from a skilled and experienced Person engaged in: (i) carrying out the same type of responsibilities of such Person in performing such actions or obligations as contemplated in this Master Agreement or an Initiative Schedule; or (ii) carrying out responsibilities, whether individually or as a package of responsibilities, which could reasonably be regarded as being comparable to the responsibilities of such Person as contemplated in this Master Agreement or an Initiative Schedule; in each case, performing its obligations under the same, reasonably comparable or similar circumstances and utilizing all the information available at the relevant time.

"**Governmental Authority**" means any federal, provincial, or municipal government, parliament or legislature, or any regulatory authority, agency, tribunal, commission, board or department of any such government, parliament or legislature, or any court or other law, regulation or rule-making entity, having jurisdiction in the relevant circumstances, including the IESO, the OEB, the Electrical Safety Authority, the Electricity Commissioner's Office, and any Person acting under the authority of any of the foregoing, but excluding the OPA.

"**Handle**" or "**Handling**" means to access, receive, collect, use, store, process, record, disclose, transfer, retain, dispose of, destroy, manage or otherwise handle.

"**HST**" means any tax payable under Part IX of the *Excise Tax Act* (Canada).

"**IESO**" means the Independent Electricity System Operator of Ontario established under Part II of the *Electricity Act*, *1998* (Ontario), or its successor.

"**IESO-Controlled Grid**" has the meaning given to it in the IESO Market Rules.

"**IESO Market Rules**" means the rules made under Section 32 of the *Electricity Act*, *1998* (Ontario), together with all market manuals, policies, and guidelines issued by the IESO or its successor.

"**Immediate Wind-down Costs**" means the costs of the LDC directly related to immediately winding up a Registered CDM Program, being:

(a) in respect of each agreement between the LDC and LDC Other Service Providers that the LDC has entered into specifically for the purposes of performing its obligations under this Master Agreement, and which the LDC has demonstrated that, after using Commercially Reasonable Efforts, it is unable to use for itself or transfer or assign to another Person, the amount of the accrued or committed expenses, costs and termination fees, if any, that the LDC is required to pay pursuant to such LDC Other Service Provider agreement in order to terminate such agreement;

(b) any unrecoverable up-front expenditures made by the LDC in order to perform its obligations under this Master Agreement in respect of such Registered CDM Program; and

(c) any other reasonable costs incurred by the LDC in assisting the OPA to terminate such Registered CDM Program,

but not including forgone revenue or profit, or any costs or expenses that could have been mitigated.

"**Indemnifiable Loss**" has the meaning given to it in Section 11.3.

"**Indemnified Party**" means an LDC Indemnified Party or an OPA Indemnified Party.

"**Indemnifying Party**" means an LDC Indemnifying Party or an OPA Indemnifying Party.

"**Industrial**" means, with respect to a particular group composed of electricity consumers, General Service > 50 kW Accounts or Large Users that carry on an activity in the Province of Ontario falling into North American Industry Classification System categories 31, 32 and 33 (Manufacturing) or subcategories 113 (Forestry and Logging), 1153 (Support Activities for Forestry) and 212 (Mining, except Oil and Gases).

"**Initial C&I Initiatives**" has the meaning given to it in Section 3.2(a).

"**Initiative**" means one or more Measures, and the activities pursuant to which such Measure or Measures are delivered, and "**Initiatives**" means each such Initiative, collectively. The specific names of certain Initiatives are set forth in Schedule A-2.

"**Initiative Schedule**" means a Schedule that sets forth the terms and conditions of one or more Initiatives and, for greater certainty, includes each Additional Initiative Schedule.

"**Initiative Term**" has the meaning given to it in Section 10.1(b).

"**Insolvency Legislation**" means the *Bankruptcy and Insolvency Act* (Canada), the *Winding Up and Restructuring Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada) or any analogous legislation, and the bankruptcy, insolvency, creditor protection or similar laws of any other jurisdiction (regardless of the jurisdiction or competence of such law).

"**Intellectual Property Rights**" means:

(a) any and all proprietary rights anywhere in the world provided under: (i) patent law; (ii) copyright law (including moral rights); (iii) trade-mark law; (iv) design patent or industrial design law; (v) semi-conductor chip or mask work or integrated circuit topography law; or (vi) any other statutory provision or common law principle applicable to this Agreement, including trade secret law, that may provide a right in either hardware, software, content, documentation, Confidential Information, Trade-marks, ideas, formulae, algorithms, concepts, inventions, processes or know-how generally, or the expression or use of such hardware, software, content, documentation, Confidential Information, Trade-marks, ideas, formulae, algorithms, concepts, inventions, processes or know-how; and

(b) any and all applications, registrations, licences, sub-licences, franchises, agreements or any other evidence of a right in any of the foregoing.

"**kV**" means kilovolt.

"**kW**" means kilowatt.

"**kWh**" means kilowatt hour.

"**Large User**" has the meaning given to such term as in the annual *Yearbook of Electricity Distributors*.

"**Laws and Regulations**" means:

(a) applicable multi-national, international, federal, provincial or municipal laws, orders-in-council, by-laws, codes, rules, policies, regulations and statutes;

(b) applicable orders, decisions, codes, manuals, interpretation bulletins, judgments, injunctions, decrees, awards, directives and writs of any court, tribunal, arbitrator, Governmental Authority or other Person having jurisdiction;

(c) applicable rulings and conditions of any licence, permit, certificate, registration, authorization, consent and approval issued by a Governmental Authority; and

(d) any requirements under or prescribed by applicable common law.

"**LDC**" has the meaning given to it in the preamble of this Master Agreement.

"**LDC Custom Microsite**" has the meaning given to it in Section 2.3(c).

"**LDC Eligible Program Administration Expenses**" means expenses of the LDC:

(a) that comprise reasonable costs of the LDC incurred prior to the Effective Date associated with preparing for the launch of the CDM Programs in 2011;

(b) are incurred after the Effective Date and are directly related to a Registered CDM Program;

(c) are Immediate Wind-down Costs; or

(d) are Post-Termination Administration Costs,

and that:

(i) have been actually incurred by the LDC (except in the case of estimated Post-Termination Administration Costs), including by payment to an LDC Other Service Provider;

(ii) do not include any LDC fees or mark-ups (which prohibited mark-ups include, for example, profit margin, management or other service fees, but do not include fully-burdened overhead allocated by the LDC in accordance with Ontario Energy Board's report of November 28, 2007, *Application of Cost Allocation for Electricity Distributors* (EB-2005-7-0667); and

(iii) in the case of an expense for the purchase of a capital asset, include only the applicable yearly cost of such asset attributable to the asset during the period that is the shorter of the Term and the life of the asset, based on an amortization of the asset over its life in accordance with the approach to the amortization of comparable assets applied to the LDC by the OEB in connection with the LDC's regulated operations,

and, for certainty, are not Participant Incentives, supplements of Participant Incentives or expenses of the LDC for which the LDC has been paid a Capability Building Funding Amount or a Participant Based Funding Amount.

"**LDC Event of Default**" has the meaning given to it in Section 10.2.

"**LDC Expenditure Policies**" has the meaning given to it in Section 4.1.

"**LDC Indemnified Party**" has the meaning given to it in Section 11.4.

"**LDC Indemnifying Party**" has the meaning given to it in Section 11.3.

"**LDC Marks**" means the LDC marks that are provided by the LDC to the OPA from time to time.

"**LDC Microsite Pages**" has the meaning given to it in Section 2.3(b)(iii).

"**LDC Other Service Provider**" has the meaning given to it in Section 2.7(a).

"**LDC Property**" has the meaning given to it in Section 5.3(a).

"**Local Distribution Company**" means the owner or operator of a Distribution System that is licensed by the OEB as an electricity distributor.

"**Low Income**" means, with respect to a particular group of electricity consumers, electricity consumers that are below specified household income levels, are recipients of specified social benefits, are social and assisted housing residents or that satisfy other criteria established in an Initiative Schedule.

"**Marketing Standards**" means in respect of the CDM Programs, the branding standards developed by the OPA, as modified from time to time pursuant to Section 2.3(a)(iv), setting out the requirements, standards and protocols applicable to the marketing of the CDM Programs and the Initiatives across all marketing channels.

"**Master Agreement**" means this Master CDM Program Agreement, including all recitals and Schedules, and Exhibits and Appendices attached to Schedules from time to time, as it or they may be amended, restated or supplemented from time to time.

"**Measures**" means: (i) any activity undertaken for the primary purpose of obtaining or effecting, directly or indirectly, CDM, including the installation, retrofit, replacement, modification or commissioning of equipment, systems, processes or behaviours that consume or result in the consumption of electricity; or (ii) any equipment, system or product related to the foregoing.

"**MFIPPA**" means *the Municipal Freedom of Information and Protection of Privacy Act* (Ontario).

"**Microsite**" has the meaning given to it in Section 2.3(a)(v).

"**Ministry Marks**" means the following trade-marks:

(i) Cleaner Ontario in English

(ii) Cleaner Ontario in French

(iii) Phrase "Our Province. Our Future" in English

(iv) Phrase "Our Province. Our Future" in French

(v) Cleaner Ontario Logo in English

(vi) Cleaner Ontario Logo in French

"**Ministry of Energy**" means Her Majesty the Queen in right of Ontario, as represented by the Minister of Energy.

"Notifying Party" means the party delivering the Change Letter Request pursuant to Section 3(a) of Schedule A-4.

"**OEB**" means the Ontario Energy Board or its successor.

"**OPA**" has the meaning given to it in the preamble of this Master Agreement.

"**OPA EM&V Protocols**" means the methods and processes that the OPA develops for the evaluation, measurement and verification of OPA-Contracted Province-Wide CDM Programs and each of the Initiatives, as such methods and processes may be amended from time to time.

"**OPA Environmental Attributes**" has the meaning given to it in Section 6.1(a).

"**OPA Event of Default**" has the meaning given to it in Section 10.4.

"**OPA Indemnified Party**" has the meaning given to it in Section 11.3.

"**OPA Indemnifying Party**" has the meaning given to it in Section 11.4

"**OPA Marks**" means the marks identifying the CDM Programs and Initiatives provided in the Marketing Standards other than the Ministry Marks and "peaksaver".

"**OPA Other Service Provider**" has the meaning given to it in Section 2.6(a).

"**OPA Property**" has the meaning given to it in Section 5.1(a).

"**OPA's Cost Effectiveness Tests**" has the meaning given to it in the CDM Code.

"**OPA Website**" means the OPA's Conservation Program website at "http://portal.ieso.ca" or such other website as the OPA may designate from time to time.

"**OPA Working Group Lead**" means the representative appointed by the OPA to the Working Group.

"**Other Service Provider**" means either an LDC Other Service Provider, an OPA Other Service Provider or both, as applicable.

"**PAB Modification Request**" has the meaning given to it in Section 4.3(c).

"PAB Reallocation Notice" has the meaning given to it in Section 4.2(c).

"**Participant**" means, in respect of an Initiative, an Eligible Person whose Application has been accepted by the LDC or the OPA, or an Eligible Person receiving a Participant Incentive and party to a Participant Agreement, as applicable, and in each case that has met all applicable requirements for participation in such Initiative as set out in the applicable Initiative Schedule, including the entering into of any required Participant Agreement.

"**Participant Agreement**" means, in respect of an Initiative, any one or more agreements that an Eligible Person entitled to receive a Participant Incentive must enter into in order to participate in such Initiative or to receive such Participant Incentive.

"**Participant Based Funding Amount**" means, in respect of an Initiative, a funding amount payable by the OPA to the LDC directly or as reimbursement for an LDC Other Service Provider for the performance of delivery tasks pertaining to such Initiative as specified in the Initiative Schedule for such Initiative.

"**Participant Incentives**" means, in respect of an Initiative, the financial incentive paid or payable to, or a discount received or receivable by, the Participant or a third party, as applicable, pursuant to the applicable Initiative Schedule or Participant Agreement.

"**Participating LDCs**" means all Local Distribution Companies prescribed an OEB-approved CDM target for their respective service areas.

"**Party**" and "**Parties**" have the meanings given to them in the preamble of this Master Agreement.

"**Payment Date**" has the meaning given to it in Section 4.7(f).

"**Peak Demand Savings**" means electricity peak demand savings determined pursuant to the OPA EM&V Protocols.

"**Peak Demand Savings Target**" means, for a specific CDM Program, the portion of the LDC's CDM Target that relates specifically to peak electricity demand savings that the LDC expects to result from such Registered CDM Program (and, for certainty, not from Board-Approved CDM Programs (as defined in the CDM Code)) as stated in the LDC's CDM Strategy or updated in the LDC's CDM Annual Report, as such CDM Target may change from time to time in accordance with Laws and Regulations.

“**Person**” means a natural person, firm, trust, partnership, association, unincorporated organization, limited partnership, company or corporation (with or without share capital), joint venture, sole proprietorship, Governmental Authority or other entity of any kind.

“**Personal Information**” means information about an identifiable individual or other information that is subject to any Privacy Laws.

“**Post-Termination Administration Costs**” means the reasonable and prudent costs of the LDC, as estimated by the LDC and approved by the OPA, acting reasonably, to comply with: (i) all of its obligations that survive the expiration or earlier termination of this Master Agreement or of a Registered CDM Program and that are directly related to the Registered CDM Programs that expire or are terminated; and (ii) all of its obligations directly related to winding up such Registered CDM Programs in an orderly manner, including all staffing, servicing and other resources which have been allocated to such Registered CDM Programs, after the expiration or earlier termination of this Master Agreement or of a Registered CDM Program.

“**Prescribed Form**” means in relation to a Participant Agreement, Application or other form, the latest version of the corresponding Participant Agreement, Application or other form appearing on the OPA Website, as may be amended, modified or replaced from time to time in accordance with Section 2.8(e).

“**Privacy Laws**” means all federal, provincial, state, municipal or other applicable statutes, laws or regulations of any Governmental Authority in any jurisdiction governing the Handling of information about an identifiable individual, including the *Personal Information and Protection of Electronic Documents Act* (Canada), FIPPA, MFIPPA and any other equivalent provincial legislation.

“**Program Administration Budget**” **or** “**PAB**” means, with respect to a CDM Program, the funding amount for such CDM Program available to the LDC for spending on LDC Eligible Program Administration Expenses, set forth in Section 1 of Schedule A-5, as adjusted from time to time in accordance with the provisions of the Master Agreement.

“**Program Management System**” means the OPA CDM Program on-line management system, as it may be modified or replaced from time to time.

“**Program Personal Information**” has the meaning given to it in Section 12.2(a).

“**Project**” means one or more Eligible Measures that are expected to be undertaken pursuant to an Initiative.

“**Receiving Party**” has the meaning given to it in the definition of Confidential Information.

“Recipient” means the party receiving the Change Letter Request pursuant to Section 3(a) of Schedule A-4.

“**Registered**” means, in relation to a Registered Initiative or a Registered CDM Program that was not deemed to be a Registered Initiative or a Registered CDM Program pursuant to Section 3.1, that (a) each of the following has occurred: (i) a Registration was submitted by the LDC to the Program Management System identifying each CDM Program and Initiative in which the LDC chose to participate in accordance with the provisions of each such Initiative Schedule; (ii) the OPA notified the LDC through the Program Management System that it was willing to enter into this Master Agreement in respect of such CDM Programs and Initiatives; and (iii) the LDC evidenced its acceptance through the Program Management System of the terms and conditions of this Master Agreement; or (b) the LDC has followed the Registration procedure in accordance with Sections 3.2 or 3.3(a)(ii).

"**Registered CDM Programs**" means: (i) the CDM Program or CDM Programs for which the LDC has been Registered; and (ii) the CDM Program or CDM Programs deemed to be included in the Registered CDM Programs pursuant to the Change Terms.

"**Registered Initiatives**" means: (i) the Initiative or Initiatives for which the LDC has been Registered; and (ii) the Additional Initiative or Additional Initiatives deemed to be included in the Registered Initiatives pursuant to the Change Terms.

"**Registration**" means the information prescribed by the OPA that the LDC is required to submit to the Program Management System or otherwise in order to be Registered.

"**Remaining C&I Initiatives**" has the meaning given to it in Section 3.2(a).

"**Representatives**" means, in respect of a Person, such Person's employees, officers, directors, shareholders, contractors, agents, representatives and advisors.

"**Residential**" means electricity consumers in Ontario that are classified as residential in the most recent *Yearbook of Electricity Distributors* published by the OEB.

"**Savings Milestones**" means, for a specific CDM Program, the peak demand savings that the LDC anticipates to achieve for each year of the Term in order to meet its Peak Demand Savings Target and the electricity savings that the LDC anticipates to achieve for each year of the Term in order to meet its Electricity Savings Target, as the same are set forth in the LDC's CDM Strategy and Annual Report, as each is submitted pursuant to the CDM Code.

"**Senior Conference**" has the meaning given to it in Section 13.2.

"**Sublicence**" has the meaning given to it in Section 5.6(a).

"**Taxes**" includes any taxes, duties, fees, premiums, assessments, levies, payments and other charges of any kind whatsoever imposed by any Governmental Authority, including all interest, penalties, fines and liabilities required by the *Income Tax Act* (Canada), and payments in lieu of taxes under the *Electricity Act, 1998* (Ontario), or other additional amounts imposed by any Governmental Authority in respect thereof, but does not include Applicable Taxes.

"**Term**" has the meaning given to it in Section 10.1(a).

"**Trade-marks**" means trade-marks, trade-names, brands, trade dress, business names, domain names, designs, graphics, logos and other commercial symbols and indicia of origin whether registered or not and any goodwill associated therewith.

"**Working Group**" means the committee made up of LDC representatives that have been selected by the EDA CDM Caucus and one or more individuals appointed by the OPA to review proposed changes to a Registered Initiative, monitor success of the Registered Initiative and bring forward issues with a Registered Initiative for discussion and resolution.

SCHEDULE A-2

CDM PROGRAMS AND INITIATIVES

RESIDENTIAL PROGRAM

Coupon Initiative

HVAC Incentives Initiative*

Bi-Annual Retailer Event Initiative

Appliance Retirement Initiative

Appliance Exchange Initiative

Residential and Small Commercial Demand Response Initiative*

Residential New Construction Initiative

COMMERCIAL AND INSTITUTIONAL PROGRAM (sometimes referred to herein as the "**C&I Program**")

Energy Audit Initiative**

Efficiency: Equipment Replacement Incentive Initiative**

Direct Install Lighting and Water Heating Initiative

[Intentionally deleted]

Building Commissioning Initiative**

New Construction Initiative

INDUSTRIAL PROGRAM°

Process and System Upgrades Initiatives 2011-2014: Preliminary Engineering Study Initiative

Process and System Upgrades Initiatives 2011-2014: Detailed Engineering Study Initiative

Process and System Upgrades Initiatives 2011-2014: Project Incentive Initiative

Process and System Upgrades Initiatives 2011-2014: Monitoring & Targeting Initiative

Process and System Upgrades Initiatives 2011-2014: Energy Manager Initiative

Process and System Upgrades Initiatives 2011-2014: Key Account Manager Initiative

Demand Response 3 Initiative

LOW INCOME PROGRAM

Low Income Initiative 2011-2014

*	denotes Initiatives available to both the Residential and C&I customer sectors
**	denotes Initiatives available to both the C&I and Industrial customer sectors
°	all Initiatives in the Industrial Program are available to the C&I customer sector

SCHEDULE A-3

CONTRACT ADMINISTRATION

1. Notices and other communications will be addressed as follows:

(a) If to the OPA for communications other than invoices or Registered Initiative inquiries or complaints from the public:

Ontario Power Authority
Suite 1600
120 Adelaide Street West
Toronto, Ontario M5H 1T1
Attention: Vice President, Conservation
Fax: 416-967-1947
E-mail: Andrew.Pride@powerauthority.on.ca

With a copy to:

Attention: General Counsel
Fax: 416-969-6383
E-mail: Michael.Lyle@powerauthority.on.ca

(b) If to the OPA for invoices for payment:

Ontario Power Authority
Suite 1600
120 Adelaide Street West
Toronto, Ontario M5H 1T1
Attention: Accounts Payable

(c) If to the OPA for Registered Initiative inquiries or complaints from the public:

Ontario Power Authority
Suite 1600
120 Adelaide Street West
Toronto, Ontario M5H 1T1
Attention: LDC Support
Fax: 416-967-1947
E-mail: LDC.Support@powerauthority.on.ca

(d) If to the LDC for communications other than Registered Initiative inquiries or complaints from the public:

Name of the LDC:
Address:
City/Town:
Postal Code:
Attention:
Fax:
E-mail:

(e) If to the LDC for Registered Initiative inquiries or complaints from the public:

Name of the LDC:
Address:
City/Town:
Postal Code:
Attention:
Fax:
E-mail:

Any notices of an Event of Default or termination of this Master Agreement will only be given by hand delivery.

2. The initial Company Representatives of the Parties are:

(a) for the OPA:

Name: ______________________________

Title: ______________________________

(b) for the LDC:

Name: ______________________________

Title: Conservation Officer

3. The HST registration numbers of the Parties are:

(a) for the OPA:

Number: ______854195039RT0001_________

(b) for the LDC:

Number: ________________________

SCHEDULE A-4

<u>CHANGE TERMS</u>

1. **Introduction**

(a) The Parties acknowledge that the CDM Programs and the Initiatives have been developed in collaboration between the OPA, certain Local Distribution Companies and the EDA Representative, primarily through the activities of certain working groups. The Parties acknowledge and agree that the OPA, the Participating LDCs and the EDA Representative will, during the Term, take reasonable steps to continue such collaboration for, among other things, managing any necessary or desirable changes to the CDM Programs and the Initiatives (the "**Collaboration Process**"). Notwithstanding that the LDC may elect to not participate directly in the Collaboration Process, it is the intention of the Parties that the OPA and the EDA Representative and, the Participating LDCs will implement the Collaboration Process in a manner that reflects principles to be determined by working groups to be continued or established, which principles will include continuous improvement of the Initiatives, consistency and predictability of the Initiatives from the perspective of the Parties and the Participants, objective rationale for change, materiality thresholds for change, focus on province-wide scope and adherence to the Directive and Laws and Regulations.

(b) The Parties acknowledge and agree that:

(i) pursuant to the Directive, the OPA is required to design the CDM Programs and to take all reasonable steps to collaborate with Local Distribution Companies in respect thereof; and

(ii) the LDC does not participate in the Initiatives that are not Registered Initiatives..

2. **[Intentionally deleted]**

3. **Change Request**

(a) A Change can only be triggered by:

(i) the Chair of a Working Group and the OPA Working Group Lead delivering a letter ("**Change Letter Request**") to the OPA describing the requested Change (which Change may relate only to the Registered Initiative(s) which such Working Group has been formed to monitor and review), together with the reasons for and impacts of such Change; or

(ii) the OPA or the EDA Representative delivering a Change Letter Request to the other party (the OPA or the EDA Representative as applicable) describing the requested Change, together with the reasons for and impacts of such Change.

In the case of a Change Letter Request delivered to the OPA, the Change Letter Request must be signed by either the Chair of the Working Group and the OPA Working Group Lead or the EDA Representative. In the case of a Change Letter Request delivered by the OPA, the Change Letter Request must be delivered to the EDA Representative.

(b) Within 10 Business Days after receipt of the Change Letter Request by the Recipient, the Recipient will respond to the Notifying Party, and either accept or reject the requested Change at its sole discretion, or the Recipient may also advise that it requires a reasonable amount of additional time to consider the Change.

4. **Acceptance or Rejection of Change**

(a) If the Recipient rejects or wishes to negotiate the proposed Change, the Recipient will notify the Notifying Party in writing. The Change process will terminate immediately, and the parties will consider the Recipient's response.

(b) If the Recipient accepts the Change, the OPA will within 10 Business Days after issuance of the notice described in Section 2(b) of this Schedule, issue a notice ("**Change Notice**") to the EDA Representative and all LDCs. The Change Notice will contain:

(i) a blackline of the Initiative Schedule showing the requested Change, where applicable;

(ii) the original Letter Request signed by the Chair of the Working Group and the OPA Working Group Lead, where applicable;

(iii) where revisions to a Prescribed Form or Eligibility Criteria or any other provisions of this Master Agreement or Schedules hereto are necessary or appropriate to implement the Change, a blackline of the Prescribed Form, Eligibility Criteria, Master Agreement or Schedule hereto, as the case may be, showing such revisions;

(iv) where it is necessary or appropriate to adopt a new Prescribed Form or new Eligibility Criteria to implement the Change, such new Prescribed Form or Eligibility Criteria;

(v) where it is necessary or appropriate to delete a Prescribed Form in its entirety or to delete Eligibility Criteria in their entirety to implement the Change, the Prescribed Form or Eligibility Criteria to be deleted; and

(vi) any additional information that the OPA chooses to provide.

5. **EDA Representative Consideration of Change**

(a) The proposed Change, and changes to Prescribed Form(s) and Eligibility criteria, as applicable, will take effect and be binding on the OPA and on all LDCs 12 Business Days after the OPA delivers the Change Notice to the EDA Representative, unless within 10 Business Days after receipt of the Change Notice, the EDA Representative either (I) rejects the proposed Change pursuant to Section 5(b) at the EDA Representative's sole discretion, or (II) advises the OPA that they require more time to consider the proposed Change, in each case by delivering a notice to the OPA, with a copy to the Chair of the Working Group and all LDCs. For certainty, if the EDA Representative does not respond within 10 Business Days, then the EDA Representative will be deemed to agree with the proposed Change, which will be binding on the OPA and all LDCs.

(b) If the EDA Representative rejects the proposed Change, or wishes to make any amendments to it, it will deliver a responding letter to the OPA, with a copy to the OPA Working Group Lead, the Chair of the Working Group and to all LDCs. The Change process will terminate immediately, and the Working Group will consider the EDA Representative's response.

6. **[Intentionally deleted]**

7. **[Intentionally deleted]**

8. **Change Request by the LDC**

The LDC may request a Change only through the EDA Representative, which will be required to request Changes on behalf of the LDC and all other affected Participating LDCs by the delivery to the OPA of a Change Letter Request as set out in Section 2(a) of this Schedule.

9. **[Intentionally deleted]**

10. **[Intentionally deleted]**

11. **[Intentionally deleted]**

12. **[Intentionally deleted]**

13. **[Intentionally deleted]**

14. **[Intentionally deleted]**

15. **[Intentionally deleted]**

16. **[Intentionally deleted]**

17. **Miscellaneous**

(a) Changes requested by the OPA concurrently will be considered by the EDA in the order determined by the OPA.

(b) Upon the OPA's reasonable request, the Parties will amend and restate this Master Agreement to reflect a consolidation of all Changes made to this Master Agreement.

SCHEDULE A-5

FUNDING AMOUNTS

1. **Program Administration Budget and Payment Schedule**

The Program Administration Budget for each Registered CDM Program for 2011 to 2014 is the amount set forth for the period “2011- 2014” in Table 1 of Exhibit A-5-1 under the heading “Program Administration Budget ($)”.

Subject to any increase or decrease in the amount of the Program Administration Budget in respect of one or more Registered CDM Programs in accordance with Section 4.3, the payment schedule for the Program Administration Budget for each Registered CDM Program is as set forth in the following Table 1:

Table 1: Payment Schedule and Payment Percentage of Program Administration Budgets for Registered CDM Programs per OPA-Contracted Province-Wide CDM Program

Payment Month	Residential Program	Commercial & Institutional Program	Industrial Program
January 2011	15%	20%	20%
July 2011	15%	20%	20%
January 2012	15%	15%	15%
July 2012	15%	15%	15%
January 2013	10%	10%	10%
July 2013	10%	10%	10%
January 2014	10%	5%	5%
July 2014	10%	5%	5%
Total	100%	100%	100%

Payment Month	Low-Income Program
January 2011	
July 2011	
January 2012	
July 2012	
January 2013	

July 2013

January 2014

July 2014

Total 100%

[NTD: OPA to populate]

The Parties acknowledge that the Program Administration Budget for the LDC for each Registered CDM Program has been determined based upon, among other considerations: (a) the number of electricity consumers in the LDC's service area, as determined by the LDC as at the Effective Date, and expected to be eligible in the CDM Programs applicable to such consumers; (b) a percentage allocation to the LDC of the Province-wide peak demand savings target and the electricity savings target for all CDM Programs as such percentage is determined by dividing the LDC's CDM Target by the aggregate CDM Targets of the LDC and all other Participating LDCs; and (c) a Term of four years.

The Parties also acknowledge that Province-wide peak demand savings target and electricity savings target set forth in Table 2 has been allocated among the LDC and all Participating LDCs in the same manner as the funds available for the aggregate Program Administration Budgets for the LDC and all Participating LDCs.

Table 2: CDM Program Savings by Year and by Term

Year	**Residential Program**		**Commercial & Institutional Program**		**Industrial Program**	
	MWh	MW	MWh	MW	MWh	MW
2011	327,431	52.846	604,041	120.590	213,890	52.014
2012	484,320	78.168	617,940	123.365	221,795	53.937
2013	541,370	87.376	631,180	126.008	222,906	54.207
2014	550,879	88.910	641,839	128.136	221,409	53.843
Total	1,904,000	307.300	2,495,000	498.100	880,000	214.000

Year	**Low-Income Program**	
	MWh	MW
2011		
2012		

2013		
2014		
Total		

[NTD: OPA to populate Low-Income Program]

2. **Cost Efficiency Incentive**

The Cost Efficiency Incentive will be calculated in respect of all Registered CDM Programs that have not been terminated pursuant to Article 10, or otherwise, as a percentage of the cost savings represented by the difference between the aggregate PAB Budgets and the aggregate Actual Spends for such Registered CDM Programs, where:

"**Actual Spend**" means the aggregate, without duplication, of the LDC Eligible Program Administration Expenses for all applicable Registered CDM Programs spent or incurred by the LDC during a specified period (and in the case of incurred expenses, paid within ninety (90) days following the end of such specified period).

"**Aggregate PAB**" means the aggregate PAB Budgets for all Registered CDM Programs in respect of a specified period.

"**PAB Budget**" is the Program Administration Budget for a Registered CDM Program, as such amount may be adjusted pursuant to Section 3.3, 4.3, 7.3 or Article 10.

The Cost Efficiency Incentive in respect of the period ending December 31, 2014 is calculated as follows:

"**Unspent PAB**" means the difference between the Aggregate PAB and the aggregate Actual Spends for all Registered CDM Programs in respect of such period.

(a) if the Unspent PAB is positive and less than or equal to 5% of the Aggregate PAB, the Cost Efficiency Incentive shall be equal to 60% of the Unspent PAB;

(b) if the Unspent PAB is positive and greater than 5% of the Aggregate PAB, and the Unspent PAB is less than or equal to 20% of the Aggregate PAB, the Cost Efficiency Incentive shall be equal to the sum of:

(i) 3% of the Aggregate PAB; and

(ii) 80% of the difference between:

(A) the Unspent PAB; and

(B) 5% of the Aggregate PAB; and

(c) If the Unspent PAB is negative or greater than 20% of the Aggregate PAB, the Cost Efficiency Incentive shall be equal to zero dollars.

Exhibit A-5-1 to Schedule A-5

Table 1 to Exhibit A-5-1: 2011 – 2014 LDC Program Administration Budget

CDM Program	**Residential**	**C & I**	**Industrial**
	Program Administration Budget ($)	Program Administration Budget ($)	Program Administration Budget ($)
2011 - 2014			

CDM Program	**Low-Income**	**Total PAB**
	Program Administration Budget ($)	($)
2011 - 2014		

[Note to Finalization: The amounts to be recorded in the cells of Table 1 above in respect of the Registered CDM Programs have been agreed to and accepted by the LDC as at the Effective Date.]

SCHEDULE A-6

REPORTING REQUIREMENTS

(a) The LDC shall break down the LDC Eligible Program Administration Expenses into the "**LDC Eligible Program Administration Expense Categories**" (listed in Exhibit A-6-1) and will report on these expenses by Registered Initiative.

(b) For each applicable Registered CDM Program the LDC shall identify the LDC Eligible Program Administration Expenses spent in respect of each LDC Eligible Program Administration Expense Category for each Registered Initiative on an Initiative by Initiative basis.

(c) In breaking down the LDC Eligible Program Administration Expenses into the LDC Eligible Program Administration Expense Categories for shared expenses that cannot be allocated solely to one Registered CDM Program or one Registered Initiative, the LDC will use an activity analysis to assess the nature and extent of the functions being performed by the LDC in respect of which the LDC Eligible Program Administration Expenses are being allocated. The analysis must include the identification of all activities performed by the LDC in respect of each Registered Initiative and allocate expenses to CDM Program delivery activities (as opposed to regulated activities) as provided by the CDM Code.

(d) All LDC Eligible Program Administration Expenses that are required to be reported pursuant to this Schedule will be reported net of recoverable Applicable Taxes that may have been incurred by the LDC on such expenses.

Exhibit A-6-1 to Schedule A-6

Categories for Reporting of LDC Eligible Program Administration Expenses

The following categories must be used, as applicable, for the reporting of LDC Eligible Program Administration Expenses:

(a) all salaries and labour costs including benefits;

(b) LDC Other Service Provider expenses;

(c) billing and collection expenses;

(d) customer care, advertising, and marketing expenses;

(e) information technology expenses;

(f) office equipment expenses; and

(g) any other expense that the LDC can show is relevant and necessary for a Registered Initiative.

SCHEDULE A-7

<u>MINISTRY MARKS</u>

1. Cleaner Ontario
2. L'Ontario plus propre
3. Our Province. Our Future
4. Notre province. Notre future
5. Cleaner Ontario logo design in color (below)
6. Cleaner Ontario Logo in black and white (below)
7. L'Ontario plus proper logo design in color (below)
8. L'Ontario plus proper logo design in black and white (below)