Ontario Energy Board (Board Staff) INTERROGATORY #001

Reference:
Exhibit A, Tab5, Sch1

Interrogatory:
In 2015, Hydro One underwent a change in corporate structure which included the issuance of ownership shares to outside investors.

a) Please provide a summary of the impacts of this change with regard to this application with particular regard to financial impacts that would affect customers.

b) Please advise what impact, if any, the change in corporate structure will have on Hydro One's governance.

Response:
a) All transactional costs associated with Hydro One's initial public offering (IPO) have been borne solely by Hydro One's shareholder. These costs include, but are not limited to, the payment by Hydro One of the $2.6 billion Departure Tax, advisory costs, legal costs, prospectus and securities costs, and underwriting commissions.

   The ongoing costs associated with Hydro One becoming a publicly traded entity are related solely to company's new governance structure, as described in part (b) of this response and as set out in IR I-13-018. The changes in cost associated with Hydro One's senior leadership team are not a function of the IPO.

   They are directly attributable to Hydro One Limited's new governance structure.

   As described in part (b) herein, the government of Ontario decided, in conjunction with the planned sale of shares of the company to the public, that it was appropriate for it to step back from the day-to-day management of the company. Accordingly, it appointed an Independent Board of Directors and executed the Governance Agreement that is described in part (b) of this response.

   The Independent Board of Directors determined that in order to improve the performance of the company, it was necessary to increase the commercial orientation of the organization;

that is, increase the company's focus on customers, create greater corporate accountability for performance outcomes, and drive company-wide increases in efficiency and productivity.

The statutory obligation of the Board of Directors is to manage the company. To fulfill this obligation, the Board of Directors delegates this responsibility to management. In order to achieve its commercial objectives, the Independent Board of Directors determined that senior managers with proven track-records of delivering the targeted commercial objectives were needed. The individuals with these skills have been added to Hydro One's senior leadership team and have been empowered by the Independent Board of Directors to achieve these commercial objectives.

The successful achievement of these commercial objectives (increased focus on customers, greater corporate accountability for performance outcomes, and increased company-wide efficiency and productivity) will be evident in all facets of Hydro One's businesses, which as of the date of this application are 99% rate regulated (by revenue).

b) The Province decided to broaden the ownership of Hydro One pursuant to an initial public offering (IPO) of Hydro One's common shares in order to strengthen the long-term performance of Hydro One and generate value for Ontarians. Following the IPO and the Province's additional sale of the common shares in Hydro One Limited ("Hydro One") completed to date, the Province continues to directly own 416,803,660 common shares, representing approximately 70.05% of Hydro One's total issued and outstanding common shares and the public owns the remaining common shares. As a result of the issuance of ownership shares, the Province is no longer Hydro One's sole shareholder. Hydro One is now a publicly listed company, and the impact on governance is described below.

Hydro One and the Province signed a Governance Agreement on November 5, 2015 in connection with the closing of the IPO. The Governance Agreement describes certain principles that govern how Hydro One will be managed and operated, including that the Province, in its capacity as a largest holder of common shares, will engage in the business and affairs of Hydro One as an investor and not as a manager. It is described in Exhibit A, Tab 5, Schedule 1 and provided in Exhibit I, Tab 2, Schedule 6.

The Governance Agreement: (i) requires that except for the CEO, all board members be independent of Hydro One and independent of the Province; (ii) addresses the director nomination process, including the requirement to maintain a board of between 10 and 15 members and prescribing the maximum number of directors that may be nominated by the

Province; (iii) requires Hydro One to maintain a majority voting policy for director elections and restricts the Province's ability to withhold from voting for directors except where the Province replaces the entire board other than the CEO and, at the Province's discretion, the board chair; (iv) requires approval by special resolution of the directors of the appointment and annual confirmation of the CEO, the board chair and changes to key governance practices of the company; (v) restricts the right of the Province to exercise certain shareholder rights, such as to requisition a shareholder meeting to consider a fundamental change, or to solicit others to exercise rights which the Province is restricted from exercising; and (vi) restricts the acquisition of voting securities by the Province but grants the Province pre-emptive rights with respect to future issuances of voting securities.

Ontario Energy Board (Board Staff) INTERROGATORY #002

Reference:

Exhibit A and Auditor General's Report, Fall 2015

Interrogatory:

The 2015 Ontario Auditor General's report identified a number of areas of concern for Hydro One and in particular, the transmission system. The most significant concerns cited by the auditor general were:

- Deterioration of system reliability
- Backlogs of preventative maintenance
- High risk assets not being replaced
- Significant assets beyond expected life still in use
- Asset analytics not considering all factors for asset replacement decisions.
- Inaccurate data in OEB funding requests
- Limited security for electronic devices.

Please provide a summary of how the areas of concern cited by the Auditor General were addressed in this application.

Response:

Deterioration of System Reliability

The Auditor General evaluated the reliability trend based upon two distinct data points; 2010 and 2014. Due to annual variations caused by weather and major or force majeure events, determination of trends in reliability is meaningful using 3 or 5 year rolling averages, which normalize these variations. Based on this industry accepted approach, Hydro One's transmission reliability has remained relatively constant as indicated by the reliability performance metrics provided in Exhibit B1, Tab 1, Schedule 3 of the application.

To improve its ability to more accurately measure the effect of system investment on reliability Hydro One has done the following:

- Supplemented its existing analysis with an additional model to quantify reliability risk which provides a directional indication of the effect of system investment on future transmission system reliability.

- Continued initiatives to reduce the number of planned outages by combining, and better scheduling, capital and maintenance activities undertaken during outages.
- Improved the performance of single circuit delivery points, which by design are not as reliable as delivery points served by multiple circuits. Single-circuit delivery point reliability has increased over the 2010 to 2014 period, as shown by the improved SAIDI and SAIFI results and lower planned outages.

Backlogs of Preventative Maintenance

In regard to backlogs of preventative maintenance, Hydro One's practice is to release more maintenance orders than available execution resources. This strategy provides execution scheduling flexibility and enables work bundling and crew redeployment in the event of outage cancellations. In addition, in 2014, a large amount of work orders for PCB testing, needed to ensure compliance with federal regulations, was released to enable efficient scheduling and bundling of this work. Hydro One expected this volume of PCB related work orders to be completed by 2020, and does not consider these to be a backlog of incomplete work due to poor planning, rather a conscious decision to add these work orders to improve the visibility of this long-term initiative.

Although Hydro One does not believe this practice has negatively affected system reliability, it has addressed this issue by recently developing a process to help asset planners better monitor the status of preventative maintenance orders and maintenance spending to aid them in identifying and prioritizing equipment that should be replaced due to poor performance or excessive maintenance costs.

High Risk Assets

The Auditor General made conclusions regarding the deferral or delay in replacing transformers. This conclusion was solely based on asset condition information but without the benefit of the full information that Hydro One uses in determining asset replacement. Overall fleet condition informs the capital spending level but cannot be used to determine the specific asset replacements. Asset Condition is not the sole consideration in determining the need to replace an asset. These replacement decisions take into account other factors as described in Exhibit B1, Tab 2, Schedule 5. Conversely, assets in good condition may need replacement based on other factors such as environmental, health and safety, inadequate capacity and customer needs and preferences, while assets that are deteriorated may be deprioritized due to their having a less material impact on the system.

Hydro One has addressed these concerns by ensuring all transformers selected for replacement in 2017 and 2018 are supported by detailed assessments based on the factors described in Exhibit B1, Tab 2, Schedule 5. As part of the process Hydro One also engaged a reputable third party, Electric Power Research Institute (EPRI) to assess overall transformer fleet health based on dissolved gas analysis.

Significant assets beyond Expected Useful Life still in use

As defined in Exhibit B1, Tab 3, Schedule 2, the expected service life is the average time in years that an asset can be expected to operate under normal system conditions. It does not imply the asset will need immediate replacement beyond this period of time. Hydro One operates a fleet of transmission assets that are beyond expected service life. However, Hydro One's asset management objective is to maintain asset performance while minimizing full life cycle costs. This is accomplished through proper maintenance and timely replacement which are detailed in our application. This approach benefits ratepayers by minimizing rate increases.

Asset Analytics not considering all factors for asset replacement decisions

Hydro One acknowledges Asset Analytics' data and algorithms require refinement, and Hydro One continues to take steps to implement such improvements. The purpose of Asset Analytics is to provide asset planners with convenient access to asset data and assess emerging risk factors in an efficient manner. Decisions to replace assets are made by the asset planners in part based on Asset Analytics output and also based on other factors fully described in Exhibit B1, Tab 2, Schedule 5. Asset Analytics is one tool to aid in decision making, but it is not the only factor considered.

To address this issue, Hydro One intends to continue improving Asset Analytics, including addressing data gaps, improving functionality and refining the algorithms used. However Hydro One does not intend that it become the sole source of decision making for asset replacement.

Inaccurate Data in OEB Funding Requests

Hydro One endeavors to ensure all data submitted to the OEB for rate setting purposes accurately reflects its forward test year plans. In making this statement, the Auditor General appears to have focused on investments that appeared in successive applications. In practice, investments are sometimes delayed due to work execution delays or other factors including changes in priority due to changing circumstances since the last rate application. In such cases a project may be delayed in favor of completing another with a more urgent need. Hydro One believes this practice is appropriate and is consistent with its asset management responsibility. To address this concern Hydro One has provided evidence supporting the 2017 and 2018 capital spending plans. These plans are based on the best information available at the time of filing the application. Hydro One is also prepared to explain variations from its previous plans and/or OEB approved spending amounts, compared to actual work completed.

Limited Security of Electronic Devices

Hydro One has been improving electronic security concerns through its Security Code of Practice and by increasing security practices in order to be NERC compliant, and by applying security measures that are commensurate with regulatory requirements and the risk to the power system.

- Hydro One has completed the development of a comprehensive security framework. This framework is called the Hydro One Security Code of Practice which includes the Security Policy and Security Operating Standards for the organization. The Code of Practice was completed in November 2015, but was recently modified to include minor revisions required by NERC CIP v5 Standards.

- Hydro One has developed NERC Critical Infrastructure Protection (CIP) compliant Engineering Standards and Build Documentation for all power system electronic devices. It is Hydro One's policy that all devices deployed will be compliant with these standards. This will ensure standard and consistent security hardening of the devices across all stations. Only a subset of Hydro One's transmission stations is required to fully comply with all NERC CIP requirements (electronic and physical). Other stations are less impactive to grid reliability and require less stringent security measures. These non-NERC impactive stations are protected based on good utility practice. From a cost prudency perspective, different levels of security measures are deployed to stations based on their criticality to grid reliability.

Ontario Energy Board (Board Staff) INTERROGATORY #003

Reference:

Responses to Letters of Comment

Interrogatory:

Following publication of the Notice of Application, the OEB has, so far, received 9 letters of comment. Section 2.3.2 of the Transmission Filing Requirements indicates, “Transmitters are expected to file with the OEB their response to the matters raised in any letters of comment sent to the OEB related to the transmitter’s application.”

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses are filed to any subsequent letters that may be submitted in this proceeding.

Response:

On August 29, 2016, Hydro One forwarded responses to the OEB by email to be sent to all authors of the letters of comment received from the OEB, written in regards to the Hydro One Transmission Rate application. To date, no letters of comment have been received directly by Hydro One Regulatory Affairs in this matter.

Hydro One will file with the Board the responses to any subsequent letters that are submitted in this proceeding.

Ontario Energy Board (Board Staff) INTERROGATORY #004

Reference:

Exhibit A/Tab3/Sch 1/p. 5

Interrogatory:

Hydro One specifies that customers indicated that the customer consultations were valuable to them in understanding Hydro One's operations and investment process.

Please provide a list of the specific indications from customers regarding the value of the customer consultations.

Response:

This is a list of customer comments recorded in the Ipsos consultations regarding the value of the customer consultations, which were collected using feedback sheets following the described methodology in Exhibit B1, Tab 2, Schedule 2:

- *"Thanks for coming" & "Thank you. This is important."*
- *"Thank you for travelling here and going through this. It was healthy. There was some times where you have to receive critical feedback. Thank you for taking it in the room. It's gotta be two ways…I have been driving to that over the last 6 to 8 sessions to get it out of the day to day stuff and look forward five years. Healthy way of doing business. I really commend Hydro One for taking this approach."*
- *"This helps give us a more detailed trend to go on. And further detail to understand and manage."*
- *"Appreciate Hydro One coming."*
- *"If I was a customer that would be helpful for me. "What am I getting for my money?"*
- *"And I love that. I think you've done a good job of presenting but that one was the one thing that jumped out."*
- *"So your – presentation stimulated a lot of thought for us and we really appreciate being involved."*
- *"I liked the way you explained it as a spectrum without having a favourite, [the presentation of information is] objective you can spend this much and it'll have this outcome. We were a little criticized from our stakeholders that we were leading people to an answer, so keeping it objective is very valuable."*
- *"Thank you for bringing forward this information and being open to feedback."*
- *"Key point, we work well together. We don't always see eye to eye, but not looking for anyone else to work with."*

- *“The info you presented is reasonable. You explained where you came from, where your investments are coming from where you are going.”*
- *“They do a good job of getting workshops together, it’s fantastic content. They’re leading the discussion on multiple fronts, the problem is no one has the answer.”*
- *“Don’t get me wrong this was really good. 10 years ago this wouldn’t have happened. With larger organizations being represented here, a voice and somebody is listening. All good opportunity to at least have a discussion.”*
- *“…[Hydro] really reliable it has been for us, now we have more confidence. They [Hydro One] have such a system in place.”*
- *“We have been struggling for years – when are we going to get some engagement from service providers.”*
- *“I am happy to see what has happened today. The success of this meeting is based on how far our feedback gets. I want to see some active changes and discussion based on meetings as a whole. The plan needs to morph to be a success. If all this does that confirms what it is in the plan then a waste of time. I’m happy to be part of this as long as portions of discussion make it through the system.”*
- *“We think that Hydro One does a good job on the consultation and leading the discussion on all fronts. There are no answers to all of this. It is hard to say if they are being proactive in their investment, but [Hydro One is] proactive in their discussion of the risk. Hydro One is having the correct conversation”*
- *“If people in the industry hear of change coming from these types of meetings then you will get better attendance.”*
- *“Comment about the communication protocol with Hydro One, we have a standing leadership meeting every year with you, traditionally provide an overview over the asset sustainment issue, that would be a good topic. Are we still maintaining that in the new hydro one?”*
- *“Our partnership will withstand anything you throw at it.”*
- *“Bi-annual meetings really help to reduce outage.”*
- *“We understand what you're doing. It kinda makes sense but with only half the picture we can’t be engaged and say, ‘Good idea,’ or ‘Look at this based on updated reliability statistics.’”*
- *“Are you getting the full story from Hydro One? We don’t get to sit down and discuss with Hydro One – programs come out baked already. They are short term and there is no dialogue.”*
- *“Interesting [for us] to come out. We will go through a similar process.”*

From Ipsos consultation session notes:

- They indicated a low level of knowledge in Hydro One's future plans and a high level of interest to hear what was being presented.
- Overall they found the information illuminating and welcomed the opportunity to provide their feedback, as well as be a part of the process in the future.
- Participants indicated they have had a low awareness of Hydro One's plans and seemed to appreciate being involved in the discussion
- LDC's main challenge with Hydro One is communication. They feel long term plans are not communicated to them so they struggle with certain aspects of their regional planning as a result.
- They welcome the opportunity to meet with the industry and Hydro One, but find that they sometimes participate in discussions without receiving the concrete answers they desire.
- In general, participants acknowledge that this type of discussion would not have happened 10 years ago and they welcome the opportunity to hear more about Hydro One's plans for the future.

Ontario Energy Board (Board Staff) INTERROGATORY #005

Reference:

Exhibit A/Tab3/Sch 1/p. 4

Interrogatory:

Chapter 2 of the Transmission Filing Requirements indicate the importance of enhanced customer engagement and reporting on future planned customer engagement activities.

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced and summarize Hydro One's future plans regarding customer engagement.

Response:

Hydro One has historically engaged in a number of different customer engagement activities, which are detailed in Exhibit B1, Tab 2, Schedule 2. Over the past several years, Hydro One increased its focus on customer engagement by: (a) implementing a more formalized outage planning and coordination process which reaches out to customers through biannual meetings held at a number of locations around the province; and (b) developing and delivering a transmission reliability report that provides customers a concise view of the historical performance of the delivery points that supply their facilities, operating events that impacted their facilities over the past year, and the planned investments that will improve supply to their facilities. These activities have provided relevant, transparent communication with customers with a mechanism that encourages customer feedback.

In 2016, Hydro One decided that further customer engagement was needed to inform the development of the Transmission System Plan. This led to the extensive customer engagement activities in the early part of 2016 to ensure that all transmission customers had the opportunity to review information regarding the transmission system's historical reliability performance, historical investment levels, the impact of equipment failures on reliability performance, and Hydro One's assessment of reliability risk related to various investment levels going forward.

Hydro One plans to continue discussions regarding reliability performance and Sustainment capital investments on an annual basis. Hydro One also plans to continue its emphasis on the activities noted above to strengthen open transparent communications that encourage and elicit customer feedback.

Witness: Laura Cooke

Ontario Energy Board (Board Staff) INTERROGATORY #006

Reference:

Exhibit A/Tab9/Sch 1/p. 3

Interrogatory:

Hydro One indicates that it incorporated feedback given at the stakeholder session into the application and provides an example citing T-SAIFI-S and T-SAIFI-M metrics.

Please provide a list and description of any other feedback that was given and incorporated in the application.

Response:

In addition to the example cited above, please see the table below for other stakeholder feedback incorporated into Hydro One's application.

Recommendation	Action
Clearly quantify the change in reliability (and/or risk) expected for the each level of investment being considered, if possible, broken down by different assets.	Hydro One has quantified the forecast decrease in reliability risk associated with the proposed spending level for each major asset class in Exhibit B1, Tab 2, Schedule 4.
Explain the model used to measure reliability risk.	Hydro One has provided an explanation of the model in Attachment 1 to Exhibit B1, Tab 2, Schedule 4.

Witness: Oded Hubert

Ontario Energy Board (Board Staff) INTERROGATORY #007

Reference:

Exhibit A/Tab3/Sch 3/pp. 5 & 6

Interrogatory:

Table 2 shows the 'Fees Payable to Hydro One Networks for Services Provided' for 2017 and 2018. Table 3 shows 'Fees Payable by Hydro One Networks for Services Received'.

Please provide similar historical information from 2012 to 2016 for both tables.

Response:

Fees Payable by Affiliates to Hydro One Networks for Services Provided by Hydro One Networks (in $ thousands)

Services	Year	HOI	Brampton	Remotes	Telecom	B2M LP
General Counsel and Secretary Services	2012	87	174	300	87	-
	2013	83	165	329	83	-
	2014	264	202	343	101	-
	2015	285	200	317	100	0.1
	2016	930	200	335	105	0.1
Financial Services	2012	74	390	260	342	-
	2013	57	240	176	261	-
	2014	49	256	211	414	-
	2015	42	258	182	327	0.1
	2016					0.1

		72	250	267	407	
Corporate Services	2012	-	26	184	253	-
	2013	-	22	223	251	-
	2014	2	34	297	308	-
	2015	-	34	291	273	0.1
	2016	-	32	288	316	0.1
Telecommunication Services	2012	-	-	128	279	-
	2013	-	-	124	269	-
	2014	-	-	125	272	-
	2015	-	-	148	290	-
	2016	-	-	135	331	-
Lease of HONI's IT Assets	2012	-		219	471	-
	2013	-		219	471	-
	2014	-		300	580	-
	2015	-		300	580	-
	2016	-		300	580	-
Other Services (Inergi)	2012	-	-	375	1,031	-
	2013	-	- 2	352	1,130	-
	2014	-	2	359	1,086	-

	2015	-	-	407	1,375	-
	2016	-	-	354	1,430	-
Utility Operation Services	2012	-		1,760	-	-
	2013	-		1,614	-	-
	2014	-		1,701	-	-
	2015	-		2,054	-	-
	2016	-		2,108	-	-
Operations and Maintenance	2012	-		-	-	-
	2013	-		-	-	-
	2014	-		-	-	-
	2015	-		-	-	0.7
	2016	-		-	-	0.5
Supply Chain Services	2012	-		77	200	-
	2013	-		77	200	-
	2014	-		77	200	-
	2015	-		76	200	-
	2016	-		76	200	-

Fees Payable by Networks to Affiliates for HOI, Remotes and Telecom Services (in thousands)

Services	2012	2013	2014	2015	2016
HOI Services					
General Counsel and Secretary Services	882	895	799	809	905
President CEO Chair	3,395	3,423	4,793	4,815	7,205
Chief Financial Officer	788	707	710	714	542
Total	5,065	5,025	6,302	6,338	8,652
Telecom Services					
Telecom Management	12,400	14,600	14,900	15,500	16,300
Total	12,400	14,600	14,900	15,500	16,300
Remotes Services					
Metering and Line Services				148	148
Total	-	-	-	148	148

Ontario Energy Board (Board Staff) INTERROGATORY #008

Reference:
Exhibit B1

Interrogatory:
In the Hydro One Distribution rates decision (EB-2013-0416) the OEB indicated at page 35, that it "….also expects that Hydro One will consider the merits of having its DSP reviewed by an independent third party and, if done, to file that review in its next rates application. If not done, an explanation of that choice must be filed with the DSP."

a) Did Hydro One consider the merits of a third party review for its Transmission System Plan?

b) If any review was completed, what was the extent of the review and what were the results?

Response:

a) Yes. However, Hydro One had to forgo a third party review in favour of conducting a Customer Engagement prior to developing the Investment Plan. Once the plan was completed, there was insufficient time for a meaningful review to occur before the filing date of May 31, 2016.

b) Not applicable.

Witness: Oded Hubert

Ontario Energy Board (Board Staff) INTERROGATORY #009

Reference:

Exhibit B1/Tab1/Sch 1/p. 2

"Hydro One has gained additional knowledge through the ongoing testing of critical assets and expansion of the scope of condition assessments, combined with information collected about the actual performance (including failures) of individual assets. Hydro One has also been developing a greater understanding of how equipment unavailability due to condition and demographics are a leading indicator of future reliability issues, contributing to higher reliability risk. As a result of these efforts, Hydro One is continuing to prioritize replacement of assets with a goal of maintaining top quartile reliability and reducing reliability risk on the system."

Interrogatory:

a) Please define "top quartile reliability" as used in the quoted paragraph and please confirm that Hydro One uses the term "top quartile reliability" consistently throughout the filing.

b) Please confirm the following.

i. That Hydro One uses the term "reliability risk" consistently throughout the filing.

ii. Whether or not this represents the common interpretation of "reliability risk" as that term is used by electric industry organizations such as NERC or CEA.

Response:

a) Top quartile reliability is used consistently in the filing. Hydro One uses Transmission System Average Interruption Duration Index for multi-circuit supplied delivery points (TSAIDI-mc) as the measure of transmission reliability performance. Figure 21, "Sustained T-SAIDI-mc Comparison by the CEA" on Page 18, in Exhibit B2/Tab2/Schedule 1/Attachment 1 supports the "top quartile performance" statement.

b)

i. Hydro One uses the term "reliability risk" consistently throughout the filing. It is referring to the underlying risk to reliability as a result of equipment unavailability or failure, which leads to customer load interruptions or increased risk to experience interruptions.

ii. The "reliability risk" used in the application is different from the NERC "reliability risk" concept but they are related. The "reliability risk" used in the filing is explained in Part I above. NERC's "reliability risk" focuses on the bulk electric system reliability rather than the impact of an asset investment plan on a transmission system. Please refer to the NERC "Reliability Risk Management" website for more details. Hydro One is not aware of a formal "reliability risk" definition from CEA.

Ontario Energy Board (Board Staff) INTERROGATORY #010

Reference:

Exhibit B1/Tab1/Sch 3/p. 23 - External Comparisons of Reliability, Figure 8a – Comparison of Hydro One Frequency of Momentary Interruptions to CEA composite, Figure 8b – Comparison of Hydro One to Frequency of Sustained Interruptions to CEA Composite.

Interrogatory:

Please compare Hydro One’s performance in the momentary and sustained delivery point interruptions categories with the Peer Group against which Hydro One's capital expenditure performance was benchmarked in the Navigant report.

Response:

Data for the peer group is not available for the momentary and sustained Delivery point interruptions, so a comparison is not possible.

Ontario Energy Board (Board Staff) INTERROGATORY #011

Reference:

Exhibit B1/Tab1/Sch 3/p. 25 - External Comparisons of Reliability, Figure 11 – Comparison of Hydro One Delivery Point Unreliability Index to CEA Composite.

Interrogatory:

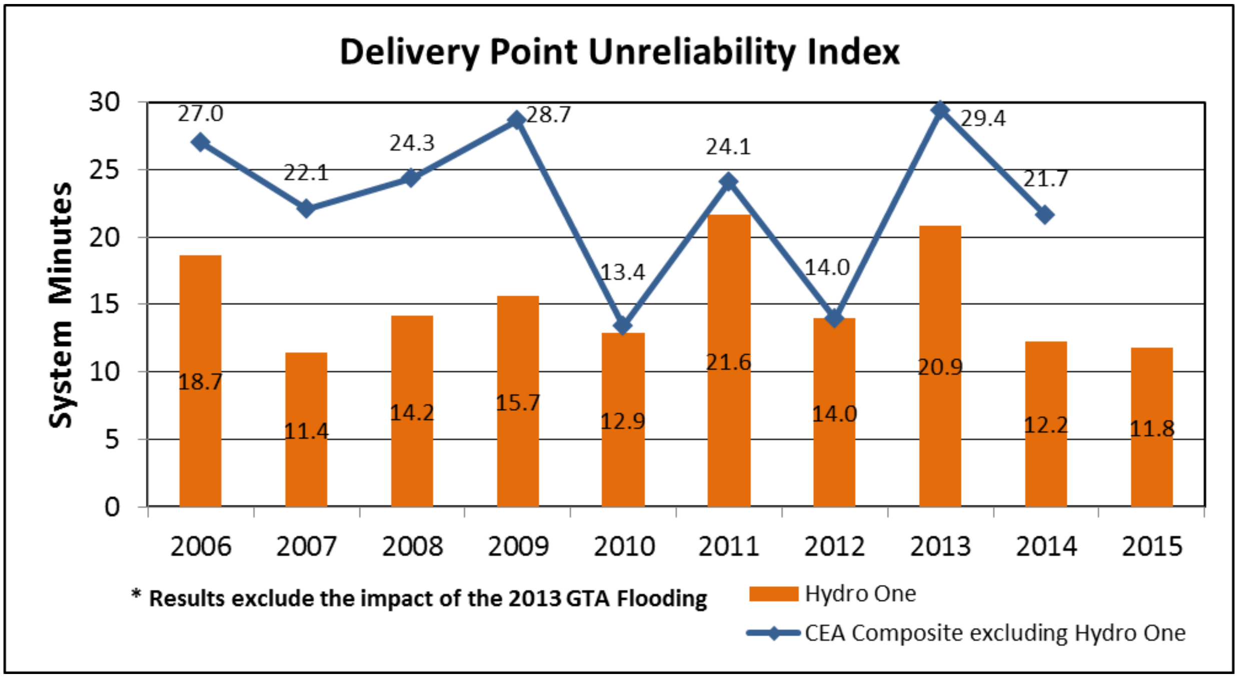
a) Please explain the reason for the apparent correlation in Figure 11 between the CEA Composite and Hydro One delivery point unreliability index results.

b) Do the Hydro One results influence the CEA composite index? If yes, is it possible to compare the Hydro One results with CEA results that exclude Hydro One, to enable a comparison with other Canadian utilities that is not influenced by Hydro One results? If so, please provide this comparison.

Response:

a) Referring to Part b) below, the Canada Composite trend, excluding Hydro One data, is generally the same as that in Figure 11. In order to investigate the correlation, a detailed study of all participants' reliability performance is required. The information required to perform that investigation is not available to Hydro One.

b) Yes. The CEA composite index is influenced by Hydro One data. A new figure with Hydro One's data excluded from the CEA composite is provided below:


Delivery Point Unreliability Index
System Minutes
30
25
20
15
10
5
0
27.0
22.1
24.3
28.7
13.4
24.1
14.0
29.4
21.7
18.7
11.4
14.2
15.7
12.9
21.6
14.0
20.9
12.2
11.8
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
* Results exclude the impact of the 2013 GTA Flooding
Hydro One
CEA Composite excluding Hydro One

Ontario Energy Board (Board Staff) INTERROGATORY #012

Reference:

Exhibit B1/Tab1/Sch 3/p. 26 - External Comparisons of Reliability, Figure 12 – Unavailability of Transmission Lines, Figure 13 – Unavailability of Major Transmission Station Equipment.]

Interrogatory:

a) Figures 12 and 13 above compare Hydro One's annual unavailability results with 5-year rolling averages of the CEA composite results. Please provide revised figures comparing <u>annual</u> Hydro One results with <u>annual</u> CEA results.

b) Do the Hydro One results influence the CEA results? If yes, is it possible to show <u>annual</u> CEA results excluding Hydro One results to enable a more meaningful comparison? If so, please provide this comparison

c) Please explain in detail the causes of the unavailability spikes that occurred in 2015 for both transmission lines and major transmission station equipment.

Response:

a) The CEA composite numbers are based on the normal industry practice for transmission equipment performance benchmarking metrics which use a five year rolling average. The CEA transmission equipment reliability report does not generate annual composite equipment performance data. Therefore, a comparison of Hydro One's annual performance with CEA composite annual results is not available.

b) Yes, the CEA composite results are influenced by the inclusion of Hydro One data. Referring to the response in part a), a comparison of the Hydro One annual performance and annual CEA results with Hydro One data excluded is not available.

c) In 2015, the spike in the transmission line unavailability was mainly due to one circuit outage caused by a falling conductor. This outage contributed 42% of total annual line unavailability.

In 2015, the spike in station equipment unavailability was mainly due to outages resulting from defective equipment with extended outage durations. The Top 11 station equipment outages contributed 42% of total annual station equipment unavailability. The details are provided in the table below:

Category	Equipment Type	Cause	No. of Outages	Contribution to Annual Unavailability
Transmission Line	Transmission Line	Defective Equipment	1	42%
Station Equipment	Power Transformer	Defective Equipment	3	11%
	Circuit Breaker		6	25%
	Shunt Capacitor		1	3%
	Shunt Reactor		1	3%

Ontario Energy Board (Board Staff) INTERROGATORY #013

Reference:

Exhibit B1/Tab1/Sch 3/p. 27 - External Comparisons of Reliability.

"Hydro One undertakes an annual detailed assessment of the cited performance measures. This assessment is taken into account along with other factors (such as asset condition) when establishing and prioritizing operating, maintenance and capital programs."

Interrogatory:

Please confirm if Hydro One assesses equipment performance independently of condition assessment. If yes, please provide examples of assets with highly rated condition assessment with simultaneously poor assessed performance.

Response:

Hydro One assesses equipment performance independently of condition assessment as described in Exhibit B1, Tab 2, Schedule 5.

The assets set out below are included in upcoming investments and have acceptable condition scores and poor performance. (For both performance and condition a high score indicates a poor rating).

Horning TS (Exhibit B1, Tab 3, Schedule 11, Reference S35)

Asset	Asset Type	Condition	Performance
Horning TS M10	Breaker	50	85
Horning TS M45	Breaker	17	100
Horning TS M46	Breaker	50	68
Horning TS M9	Breaker	50	100
Horning TS 125V Station Battery	DC Station Service	25	68

Nelson TS (Exhibit B1, Tab 3, Schedule 11, Reference S15)

Asset	Asset Type	Condition	Performance
Nelson TS M32	Breaker	17	100
Nelson TS M33	Breaker	17	100
Nelson TS T4J	Breaker	42	80

Beck #2 TS (Exhibit B1, Tab 3, Schedule 11, Reference S02)

Asset	Asset Type	Condition	Performance
Beck #2 TS DT302	Breaker	44	61
Beck #2 TS KL26	Breaker	14	61
Beck #2 TS L35L76	Breaker	44	61
Beck #2 TS TL21L23	Breaker	17	82

Bruce A TS (Exhibit B1, Tab 3, Schedule 11, Reference S03)

Asset	Asset Type	Condition	Performance
Bruce A TS D2L5	Breaker	42	87
Bruce A TS K1L24	Breaker	28	61
Bruce A TS K2L27	Breaker	14	61
Bruce A TS L4L28	Breaker	14	61
Bruce A TS R25S	Breaker	36	80
Bruce A TS T1L20	Breaker	47	67
Bruce A TS T1L22	Breaker	42	80
Bruce A TS 250V ‘A’ Station Battery	DC Station Service	32	100
Bruce A TS 250V ‘B’ Station Battery	DC Station Service	47	100
Bruce A TS 48V ‘C’ Station Battery	DC Station Service	47	68
Bruce A TS DC Distribution Panel	DC Station Service	33	100
Bruce A TS HT4L502CT	Instrument Transformer	22	100
Bruce A TS Power Line Carrier (PL00B562E02)	Telecom	33	100
Bruce A TS T1 Multiplexer (T1MX0036M)	Telecom	33	100

Ontario Energy Board (Board Staff) INTERROGATORY #014

Reference:

Exhibit B1/Tab2/Sch 4/p. 7 - Section 3.2: Reliability Risk Modeling Approach.

"Reliability risk is modelled using the relationship between asset demographics, historical asset failures and the impact that equipment has on reliability. Hydro One's risk model focuses on lines, transformers and breakers, due to their large contribution to reliability risk and criticality to the system. Calculating reliability risk based on the interruption durations attributable to these asset classes creates a measure of the substantial portion of the reliability risk on the transmission system.

The output of the risk model is a measure of the system reliability risk resulting from planned investments relative to a baseline. The model considers both the expected impact of asset replacement and the continued aging and deterioration of existing assets."

Interrogatory:

a) Please confirm that Hydro One's risk model only takes into account lines, transformers and breakers and that no other asset classes are considered by Hydro One when calculating reliability risk.

b) Please identify if this is Hydro One's first Transmission Cost-of-Service Application and Evidence Filing to employ this risk modeling approach.

c) Has Hydro One back-tested or "back-cast" its reliability risk model to validate modeled risk projections against actual reliability and outage performance? If yes, please provide the results of these back-tests.

d) Does Hydro One use the risk model output to develop capital investment budgets? If yes, please explain in detail how the risk model output is used and at what stage of the capital planning process.

e) Please provide Hydro One's methodology and quantified model outputs that were used to assess the system reliability risk impacts of the capital investments proposed in this filing.

f) If the risk model output does not identify individual capital projects, how does it provide a meaningful indication of the reliability risk mitigation effectiveness of different levels of capital investment? Please explain in detail and include quantified examples.

g) Has Hydro One used asset demographics to determine which assets need to be replaced in the absence of asset condition assessment and/or performance data? If yes, please identify which of the projects identified in this application are driven primarily by asset demographics and provide Hydro One's rationale for not field-verifying the condition/performance of these assets prior to including these projects in the present filing.

Response:

a) Confirmed. This is based on a study covering 10 years of reliability data verifying that lines, transformers and breakers are the most impactive asset types to reliability.

b) This is the first time Hydro One has introduced reliability risk model. This model is new and will improve over time. Similar methodology is being developed and used in the UK under the Office Of Gas and Electricity Markets (OFGEM).

c) No. Hydro One has not back-tested or back-cast its reliability risk model.

d) No, the risk model does not set the capital budget. Hydro One uses this model as part of its investment planning process as described in Exhibit B1, Tab 2, Schedule 4. As indicated on page 1, line 23, the process starts with "…review of the system, with a focus on reliability performance and reliability risk….". Hydro One establishes a baseline of reliability risk at the onset of investment planning exercise. This is achieved by using the transformer, conductor and breaker demographic prior to undertaking capital investments, and calculating the reliability risk. After an optimized plan is developed, the renewed transformer, conductor and breaker demographics are used to recalculate reliability risk. The before and after capital investment reliability risk provides a measurement to gauge the impact of its investments on future transmission system reliability.

e) The methodology is discussed in Exhibit B1, Tab 2, Schedule 4, Attachment 1. Details describing how this model is derived and its application are provided. The output of this model is shown as Table 1, in page 8 of B1-02-04. Refer to Staff IR 15 for calculation details.

f) Reliability risk is an outcome measure, as described in Exhibit B1, Tab 2, Schedule 4, used to gauge the impact of Hydro One's investment plan on future transmission system reliability. The model is not intended to be used to determine individual capital projects. It provides a meaningful directional relative comparison to demonstrate that a given level of capital investment reduces reliability risk.

For example, a fleet of transformers has a demographic profile such that 25% are 65 year old, 50% are 30 years old and 25% are 10 years old. Each of these units has a hazard rate, the cumulative hazard rate, or probability of failure, for this existing transformer fleet is (0.25*hazard rate at 65 years old) + (0.5*hazard rate at 30 years old) + (0.25*hazard rate at 10 years old) = X1. A capital investment plan and continued aging of assets over 2 years will change the demographic such that 20% are 67 years old, 50% are 32 years old, 25% are 12 years old and 5% are less than 2 years old. Repeating the cumulative hazard rate calculation for this new demographic profile, yields X2.

If X2 is larger than X1, it is indicative of a higher probability of failure and that the investment level is insufficient to maintain or improve reliability risk. On the other hand, if X2 is smaller than X1, it is an indication that the investment level is sufficient to maintain or improve reliability risk. This fleet and system level reliability risk is an effective outcome measure of the impact of the investment plan on future transmission system reliability. Individual capital projects are developed via the process described in Exhibit B1, Tab 2, Schedule 5.

Typical capital investments in transmission utilities take 3 to 5 years to plan, execute and place in-service. Delaying capital investments until reliability has eroded conventional SAIDI and SAIFI metrics could mean several years of reduced reliability until projects are completed to arrest and reverse the deteriorating trend. Utilizing a leading indicator such as reliability risk to help inform the capital investment level is an efficient and prudent method to help maintain top quartile reliability performance.

g) No, Hydro One has not used asset demographics as the sole justification to replace assets. Asset demographics play a role as one screening factor to help narrow down to a set of assets requiring attention. The factors that are used to determine asset replacement are described in Exhibit B1, Tab 2, Schedule 5.

Ontario Energy Board (Board Staff) INTERROGATORY #015

Reference:

Exhibit B1/Tab2/Sch 4/p. 8 - Section 3.2: Reliability Risk Modeling Approach, Table 1 – Relative Change in Reliability Risk]

"Table 1 below summarizes the expected relative decrease in risk, for each critical asset class and for the system as a whole, as a result of the 2017 and 2018 investment plan. For comparison the table also provides the relative increase in risk which will occur if no assets were replaced in the two year period."

Table 1: Relative Change in Reliability Risk

	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, as per proposed investment	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, without investment	% of Interruption Duration*
Lines	-2%	11%	69%
Transformers	-9%	14%	9%
Breakers	1%	17%	6%
Other[1]	-	-	16%
Total*	**-2%**	**10%**	

* Total is calculated by weighting the change in risk by the asset class' contribution to interruption duration.

Interrogatory:

a) Please provide a description of the methodology, the detailed calculations and the supporting data used to populate Table 1 above.

b) Does Table 1 above show the overall probability of asset failures in each asset class contributing to SAIDI, CAIDI or some other metric?

c) Is the relationship between level of capital investment and the Relative Change in Risk values shown in Table 1 linear, or are there inflection points driven by different individual investments or overall levels of investment?

d) Did Hydro One evaluate any alternative investment plans other than the "proposed investment" and "without investment" cases shown in Table 1?
   i. If yes, please provide the investment level and projected reliability risk performance of these alternative investment portfolios.
   ii. If no, please explain how the proposed plan optimizes capital investment costs against reliability risk.

e) Has Hydro One ranked its capital investments to facilitate forced prioritization of the most effective reliability risk mitigation projects if the approved level of capital investment is less than Hydro One has requested?
   i. If yes, please provide the prioritized project list.
   ii. If no, please explain how the most effective risk mitigation projects will be prioritized if the approved capital investment level is less than requested.

Response:

a) The data in the table was summarized by running the risk model as described in Exhibit B1-02-04. The example of relative change in risk from Jan 1, 2017 to Dec 21, 2018 as per the proposed investment for lines (-2%) will be presented here.

Hazard curves that describe the asset survival risk by asset type are the basis for the risk model. Hydro One uses a report prepared by Foster Associates as basis for determining hazard curves, which is based on analysis of Hydro One's historical data (reference Exhibit I, Tab 1, Schedule 20, Part b).

Next, the demographic profile of the asset (for this example the asset type is lines) is multiplied by the age-specific hazard rate to obtain a risk profile for the assets as a function of their age. The overall probability is the sum of this profile. This operation is carried out for each asset type over the rate filing period for all replacements.

The asset risk calculation for lines with planned replacements until December 2018 is shown in the table below.

Total				
Age	**Circuit KM**	**Proportion of Total**	**Hazard Rate**	**1.053%**
0.00	14.87	0.05%	0.00%	0.000000%
1.00	34	0.11%	0.00%	0.000000%
2.00	101	0.34%	0.00%	0.000000%
3.00	122	0.41%	0.00%	0.000000%
4.00	445	1.51%	0.00%	0.000001%
5.00	93	0.31%	0.00%	0.000000%
6.00	160	0.54%	0.00%	0.000001%
7.00	117	0.40%	0.00%	0.000001%
8.00	269	0.91%	0.00%	0.000005%
9.00	28	0.10%	0.00%	0.000001%
10.00	34	0.11%	0.00%	0.000001%

Age	Total KM	Proportion of Total	Hazard Rate	1.053%
11.00	19	0.07%	0.00%	0.000001%
12.00	118	0.40%	0.00%	0.000009%
13.00	113	0.38%	0.00%	0.000012%
14.00	40	0.14%	0.00%	0.000006%
15.00	91	0.31%	0.01%	0.000016%
16.00	49	0.16%	0.01%	0.000011%
17.00	13	0.05%	0.01%	0.000004%
18.00	126	0.43%	0.01%	0.000044%
19.00	100	0.34%	0.01%	0.000043%
20.00	62	0.21%	0.02%	0.000032%
21.00	33	0.11%	0.02%	0.000020%
22.00	368	1.24%	0.02%	0.000270%
23.00	58	0.20%	0.03%	0.000050%
24.00	82	0.28%	0.03%	0.000083%
25.00	792	2.68%	0.03%	0.000929%
26.00	628	2.12%	0.04%	0.000851%
27.00	355	1.20%	0.05%	0.000552%
28.00	240	0.81%	0.05%	0.000427%
29.00	5	0.02%	0.06%	0.000010%
30.00	12	0.04%	0.07%	0.000028%
31.00	10	0.03%	0.08%	0.000026%
32.00	184	0.62%	0.09%	0.000535%
33.00	231	0.78%	0.10%	0.000748%
34.00	363	1.23%	0.11%	0.001316%
35.00	159	0.54%	0.12%	0.000642%
36.00	686	2.32%	0.13%	0.003062%
37.00	342	1.16%	0.15%	0.001690%
38.00	237	0.80%	0.16%	0.001288%
39.00	403	1.36%	0.18%	0.002412%
40.00	646	2.19%	0.19%	0.004248%
41.00	292	0.99%	0.21%	0.002099%
42.00	117	0.40%	0.23%	0.000917%
43.00	640	2.17%	0.25%	0.005482%
44.00	545	1.85%	0.28%	0.005084%
45.00	1,237	4.19%	0.30%	0.012517%
46.00	1,490	5.04%	0.32%	0.016342%
47.00	386	1.31%	0.35%	0.004585%
48.00	299	1.01%	0.38%	0.003827%

Witness: Mike Penstone

Age	Total KM	Proportion of Total	Hazard Rate	1.053%
49.00	176	0.60%	0.41%	0.002434%
50.00	150	0.51%	0.44%	0.002227%
51.00	609	2.06%	0.47%	0.009744%
52.00	629	2.13%	0.51%	0.010817%
53.00	90	0.30%	0.54%	0.001656%
54.00	117	0.40%	0.58%	0.002316%
55.00	313	1.06%	0.62%	0.006607%
56.00	300	1.02%	0.67%	0.006766%
57.00	512	1.73%	0.71%	0.012331%
58.00	630	2.13%	0.76%	0.016172%
59.00	493	1.67%	0.81%	0.013464%
60.00	192	0.65%	0.86%	0.005581%
61.00	645	2.18%	0.91%	0.019919%
62.00	568	1.92%	0.97%	0.018619%
63.00	206	0.70%	1.03%	0.007158%
64.00	474	1.60%	1.09%	0.017443%
65.00	1,838	6.22%	1.15%	0.071609%
66.00	1,639	5.55%	1.22%	0.067512%
67.00	345	1.17%	1.29%	0.014998%
68.00	382	1.29%	1.36%	0.017569%
69.00	286	0.97%	1.43%	0.013859%
70.00	177	0.60%	1.51%	0.009066%
71.00	102	0.35%	1.59%	0.005509%
72.00	33	0.11%	1.67%	0.001865%
73.00	0	0.00%	1.76%	0.000000%
74.00	44	0.15%	1.85%	0.002767%
75.00	506	1.71%	1.94%	0.033293%
76.00	198	0.67%	2.04%	0.013704%
77.00	248	0.84%	2.14%	0.018006%
78.00	0	0.00%	2.25%	0.000000%
79.00	392	1.33%	2.35%	0.031184%
80.00	19	0.06%	2.46%	0.001601%
81.00	198	0.67%	2.58%	0.017237%
82.00	529	1.79%	2.70%	0.048283%
83.00	700	2.37%	2.82%	0.066827%
84.00	791	2.68%	2.95%	0.078841%
85.00	12	0.04%	3.08%	0.001246%
86.00	284	0.96%	3.21%	0.030849%

Age	Total KM	Proportion of Total	Hazard Rate	1.053%
87.00	474	1.60%	3.35%	0.053732%
88.00	60	0.20%	3.49%	0.007119%
89.00	16	0.05%	3.64%	0.001948%
90.00	87	0.29%	3.79%	0.011134%
91.00	196	0.66%	3.95%	0.026156%
92.00	106	0.36%	4.11%	0.014700%
93.00	57	0.19%	4.28%	0.008272%
94.00	25	0.08%	4.45%	0.003765%
95.00	17	0.06%	4.63%	0.002735%
96.00	0	0.00%	4.81%	0.000000%
97.00	0	0.00%	4.99%	0.000000%
98.00	0	0.00%	5.18%	0.000000%
99.00	9	0.03%	5.38%	0.001548%
100.00	0	0.00%	5.58%	0.000000%
101.00	111	0.38%	5.79%	0.021760%
102.00	293	0.99%	6.00%	0.059607%
103.00	0	0.00%	6.22%	0.000000%
104.00	0	0.00%	6.45%	0.000000%
105.00	177	0.60%	6.68%	0.039984%
106.00	23	0.08%	6.91%	0.005381%
107.00	0	0.00%	7.15%	0.000000%
108.00	0	0.00%	7.40%	0.000000%
109.00	0	0.00%	7.66%	0.000000%
110.00	4	0.01%	7.92%	0.000938%
111.00	0	0.00%	8.18%	0.000000%
112.00	0	0.00%	8.46%	0.000000%
113.00	0	0.00%	8.74%	0.000000%
114.00	0	0.00%	9.02%	0.000000%
115.00	0	0.00%	9.32%	0.000000%
116.00	75	0.26%	9.62%	0.024549%
117.00	0	0.00%	9.93%	0.000000%
118.00	0	0.00%	10.24%	0.000000%
119.00	0	0.00%	10.56%	0.000000%
120.00	0	0.00%	10.89%	0.000000%
121.00	0	0.00%	11.23%	0.000000%
122.00	0	0.00%	11.57%	0.000000%
123.00	0	0.00%	11.92%	0.000000%
124.00	0	0.00%	12.28%	0.000000%
125.00	0	0.00%	12.65%	0.000000%

For example, there are 506 circuit-km of 75 year old lines making up about 1.7% of the population with an annual probability of failure of 1.94% given that these conductors survived previously to 74 years. Therefore the probability of failure of these 75 year old, 506 circuit-km is 0.0194 x 0.017. This calculation is performed for each age group over the entire demographic distribution and summed to produce the overall probability of failure.

This process is conducted for the present assets and after the planned replacements identified in this filing, representing a 1.056% and 1.031% probability of failure respectively. The ratio of these probabilities determines the relative risk as it appears in Table 1.

$$1.031\%/1.056\% - 1 = -2\%.$$

As presented for lines, each asset type's demographic profile was multiplied by their age-specific hazard rates to obtain a risk profile for the assets as a function of their age. This was summed up as in the example for lines and these values are presented in Figure1 below under 'supporting data'. Future demographic asset distributions were used for the 'Proposed Investment' and 'Do Nothing' scenarios. For the 'proposed investment', the future demographics takes into account the aging of assets that are not replaced as well as those that are removed due to replacement. For the 'Do Nothing' scenario the presently installed assets are aged to the end of 2018.

Supporting Data				Calculations for Table 1				
Asset Type	Proposed Investment for 2017/18		"Do Nothing" After 2016	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018 as per proposed investment		Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018 without investment		% of Interruption Duration *
	Jan. 1, 2017	End of Rate Filing Period	Jan. 2019					
Lines	1.056%	1.031%	1.17%	1.03 / 1.06 -1 =	-2%	1.17 / 1.06 - 1 =	11%	69%
Transformers	1.694%	1.535%	1.92%	1.54 / 1.69 -1 =	-9%	1.92 / 1.69 - 1 =	14%	9%
Breakers	2.610%	2.633%	3.05%	2.63 / 2.61 - 1 =	1%	3.05 / 2.61 - 1 =	17%	6%
				(-2% x 69%) + (-9% x 9%) + (1% x 6%) =	-2%	(-2% x 69%) + (-9% x 9%) + (1% x 6%) =	10%	

Figure 1

The totals in the bottom row as filed and presented in Table 1 utilize the SAIDI interruption data to weigh the overall probabilities of failure of each asset type as shown above. Figure 1 demonstrates the calculation of the total risk by weighing the relative risk of the asset type by the SAIDI interruption data and then summed up over all the assets.

b) As stated, the columns in Table 1 presenting the asset-specific relative risks are based on the computed overall probabilities of failure. It does not include outage interruption data (SAIDI) and is based on historical replacement rates. Note that in the case of multiple supply delivery points, an equipment failure will not result in SAIDI, CAIDI implications but will increase the risk of reliability while under the single supply condition.

c) The reliability risk is a function of asset demographics and hazard curves, which are non-linear. As such, the relationship between capital investment level and relative change in reliability risk is also non-linear. However, there is a positive correlation, a higher level of investment leads to more improvement in reliability risk.

d) Yes, Hydro One evaluated alternative investment scenarios, which were discussed as part of the customer engagement included in Exhibit B1, Tab 2, Schedule 2, Attachment 2, Transmission Customer Engagement: Investing for The Future, Page 23. Three indicative investment scenarios over a 5 year planning period were discussed. Respective reliability risk associated with Scenario 1, 2 and 3 are increased by 9%, increased by 2% and reduced by 10%.

e) Yes. Hydro One has prioritized its proposed investments at the corporate level. The prioritized project list takes the form of the optimized portfolio of investments filed in this application. In the event of a reduced approved level of capital investment, Hydro One will reduce its work program using the optimization criteria (Exhibit B1, Tab 2, Schedule 7).

The expected outcome is an increase in reliability risks and potential future deterioration in actual reliability performance. In this scenario, a load serving transformer in poor condition is ranked the lowest and may not get replaced, effective placing it under run to failure option, which is highly impactive to reliability.

Ontario Energy Board (Board Staff) INTERROGATORY #016

Reference:

Exhibit B1/Tab2/Sch 4/p. 9 - Section 4.1: Relationship between Maintenance Expenditures and Capital Investment.

"Hydro One has relied on maintenance programs to extend the lifespan of assets by continually addressing asset condition deficiencies, where practical, as a means of deferring large capital expenditures. As a result assets are being operated beyond their expected service life ("ESL"). Although this approach defers capital investments, it increases maintenance costs and the risk that assets will fail, deteriorate significantly or become obsolete as spare parts and manufacturer support is becomes unavailable.

The following examples illustrate situations where these risks were manifest:

- *Elgin TS and Horning TS were constructed in Hamilton in 1968 and 1967 respectively. Although the equipment at both stations was in a deteriorated condition, Hydro One continued to keep them operating through continual corrective maintenance. Capital investments to refurbish these stations were planned in 2015 and 2016 respectively.*
- *In 2015, significant equipment failures also occurred with Bridgman TS (Toronto), built in 1952, and Frontenac TS (Kingston), built in 1938, due to deteriorating assets. These failures caused reliability and public safety concerns due to their locations. In the case of the Frontenac failure, Kingston and surrounding areas lost power for over 12 hours."*

Interrogatory:

a) Please explain how Hydro One decides whether to replace or to extend the lifespan of deteriorated assets.
   i. Did Hydro One decide to refurbish Elgin TS and Horning TS in 2015 and 2016 because Hydro One's capital investment decision-making process indicated that it was better to refurbish these assets rather than replace them? Please explain.
   ii. Did Hydro One decide to defer refurbishing or replacing Bridgman TS and Frontenac TS because Hydro One's capital investment decision-making process indicated that replacement or refurbishment was not necessary? Please explain.
   iii. Does Hydro One perform cost-benefit analysis before making each such decision?
   iv. If yes, please provide the cost-benefit analyses for Elgin TS, Horning TS, Bridgman TS, and Frontenac TS.
   v. If no, please explain how Hydro Once made its evaluations and decisions for Elgin TS, Horning TS, Bridgman TS, and Frontenac TS.

b) Please define the activities represented by the terms "continual corrective maintenance" and "refurbish" as used in the above reference.

Witness: Mike Penstone

c) Please identify if Hydro One has made any changes to its capital investment process as a result of its experiences with Elgin TS, Horning TS, Bridgman TS and Frontenac TS.
   i. If any changes were made, are those changes quantifiable, i.e.: has the risk weighting calculation algorithm been modified? Please provide the algorithm and details of any algorithm changes.

Response:

a)
   i. In the context of this evidence, refurbishment refers to replacing deteriorated equipment with new equipment within an existing station site. Elgin and Horning will be refurbished by using new power equipment and assets as described in the Investment Summary Document S11 and S35. Refurbishing these stations at their existing location with new equipment is the lower cost option than building new stations at an alternate site(s).

   ii. Bridgman and Frontenac were not deferred. In both cases, capital investments were released and in the process of being executed when equipment failures took place. Ideally these assets would have been replaced just prior to failure, but an exact prediction of asset failure is not possible.

   iii. Elgin, Horning, Bridgman and Frontenac are transmission stations with multiple obsolete assets in deteriorated condition that required replacement. Asset lifespan extension was not an option and therefore a cost-benefit analysis was not performed.

   iv. Not applicable.

   v. Elgin, Horning, Bridgman and Frontenac are transmission stations with multiple end of life assets due to obsolescence, poor performance and deteriorated condition which require replacement. Asset life extension was not an option. In addition, based on technical, operability, environmental and reliability considerations, asset replacement is the only feasible option.

b) Continual corrective maintenance refers to increased maintenance repairs to deal with equipment failures to keep assets at these stations functioning at the expense of reduced reliability. Refurbishment in this context is referring to replacing equipment that has reached end of life with new equipment within an existing station site.

c) To date, Hydro One has not made any changes to its capital investment process. The lesson learned from this experience is that Hydro One cannot rely on using continual corrective maintenance to defer required capital investment. These experiences do highlight the importance of executing timely capital investments to prevent reliability deterioration. Consistent with the customer consultation feedback, Hydro One seeks to maintain first quartile reliability and minimize reliability risk.

Ontario Energy Board (Board Staff) INTERROGATORY #017

Reference:

Exhibit B1/Tab2/Sch 4/p. 12 – Section 6: Sustainment Forecast and External Constraints

"The ESL profile of Hydro One's asset base suggests that significant sustainment capital will be needed between 2016 and 2030 in order to prevent an increase in reliability risk. A sizable portion of each critical asset class is operating beyond expected service life, contributing to an increase in reliability risk. Specifically, 28% of transformers, 9% of breakers and 19% of conductors are currently operating beyond their normal expected service lives."

Interrogatory:

a) Please describe in detail how Hydro One assesses and tracks the age of its assets (i.e.: is the asset age determined solely by the original asset commissioning date, or does Hydro One use an adjusted age based upon the results of condition assessments?)

b) Did Hydro One utilize actuarial values of expected service lives when deciding which sustainment projects to include in its filed sustaining capital plan?

c) Please provide details of the methodology Hydro One uses to calculate "Expected Service Life" for different asset classes.

d) Does Hydro One adjust the expected service lives of assets based upon the results of its asset condition assessment procedure?

e) How often does Hydro One update its "Expected Service Life" calculations?

f) Do "Expected Service Life" updates incorporate updated actual Hydro One asset performance data?

g) Please confirm that Hydro One has performed recent asset condition assessments for all major assets scheduled to be replaced as part of the sustaining capital projects included in this filing. If not confirmed, please identify which filed sustainment projects involve replacing major assets that have not had a recent asset condition assessment.

Response:

a) Hydro One assesses and tracks the age of its assets based on the year the specific asset was manufactured for breakers, transformers, switches, reactors, capacitors, wood poles etc., and the asset commissioning date for the overall transmission line sections and transmission stations. The adjusted age based on the results of a condition assessment are not used in establishing the age of an asset.

b) No. Hydro One did not utilize actuarial values of expected service lives when deciding which sustainment projects to include in its filed sustaining capital plan. The sustainment projects that are included in the filed sustaining capital plan are based on need as documented in Exhibit B1, Tab 2, Schedule 5.

c) Hydro One defines “expected service life” as meaning the average time in years that an asset can be expected to operate under normal system conditions. Hydro One determines the “expected service life” of its assets using statistical analysis of the relevant population of assets and it is the expected age of survival.

d) No, Hydro One does not adjust the expected service lives of assets based upon the results of its asset condition assessment procedure.

e) Hydro One updates its expected service life calculations generally every five years or as required to analyse specific asset mortality rates. The last update was completed in 2014 as per Foster Associates Report, “2014 Asset Failure Analysis.”

f) Yes, the “Expected Service Life” is specific to Hydro One assets only. It is reflective of the Hydro One fleet of assets currently in-service and the associated history of failures and retirements.

g) Yes.

Ontario Energy Board (Board Staff) INTERROGATORY #018

Reference:

Exhibit B1/Tab2/Sch 4/p. 15 – Section 6: Sustainment Forecast and External Constraints, Figure 5 – Anticipated Sustainment Work Volume

Interrogatory:

a) Please confirm that the anticipated sustainment work volume post-2016 shown in Figure 5 replicates Hydro One's original annual asset installation counts by asset class starting in 1949, effectively implying a fixed 68-year asset replacement cycle across all asset classes.

b) Please confirm that Hydro One is not proposing to follow the implied 68-year asset replacement cycle shown in Figure 5.

c) Please provide an updated Figure 5 with an asset replacement cycle that reflects the expected service lives of different asset classes and Hydro One's current asset base.

Response:

a) The anticipated sustainment work volume post-2016 shown in Figure 5 replicates Hydro One's original annual asset installation counts by asset class starting in 1949 of assets that are currently in service. This is not intended to imply a fixed 68-year replacement cycle across all asset classes, but demonstrates the number of assets that are presently operating at or beyond their expected service life ("ESL") that may require refurbishment or replacement post-2016.

b) Hydro One does not propose to follow a 68-year asset replacement cycle as shown in Figure 5. The proposed sustaining capital work volume to replace and/or refurbish assets is identified in Exhibit B1, Tab 3, Schedule 2.

c) An updated Figure 5 is provided below applying the expected service life, as documented in Exhibit B1, Tab 2, Schedule 6, of each asset class; transformers, breakers, and conductor. The quantity of assets operating beyond ESL is noted in the revised Figure 5 below.

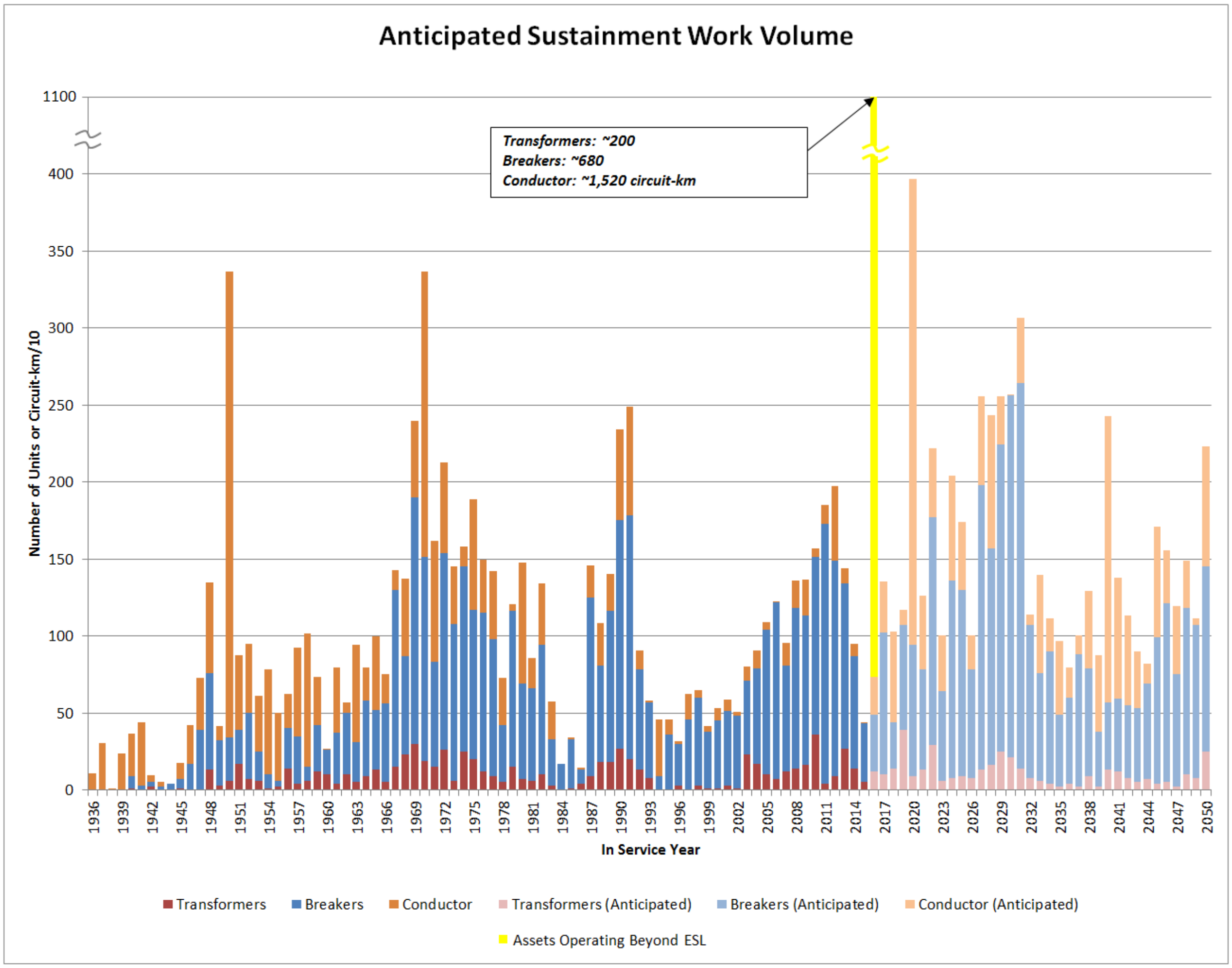


Figure 5: Anticipated Sustainment Work Volume

Ontario Energy Board (Board Staff) INTERROGATORY #019

Reference:

Exhibit B1/Tab2/Sch 4/ Attachment 1 – Reliability Risk Model, pg. 1]

"Hydro One's reliability risk model relies on three key inputs, which are detailed below: asset-specific hazard curves, the asset demographic of Hydro One's current fleet, and the total units of each asset class that are planned to be replaced. The reliability risk model is used to help inform the level of investment required to manage system reliability risk."

Interrogatory:

Does the increased amount of intermittent generation on the Hydro One system, relative to the historic period from which reliability / hazard curves were developed, change the expected useful life of any of Hydro one's key assets?

Response:

The expected useful life of Hydro One's key assets has not changed and no assets have been replaced prematurely due to intermittent generation. Hydro One ensures that equipment is operated within its design limits.

Ontario Energy Board (Board Staff) INTERROGATORY #020

Reference:

Exhibit B1/Tab2/Sch 4/ Attachment 1 – Section 1: Hazard Rates, pp. 1-2

"The Hazard Rate represents the conditional probability of failure, including retirements, in a year given that the asset has survived through the previous years.

Hydro One's hazard curves were developed based on the results from a report commissioned from Foster Associates entitled, "2014 Asset Failure Analysis." Foster Associates determined the hazard curves for each asset class based on Hydro One's actual asset demographic data (including vintage and in-service dates) and Hydro One's actual asset failures and retirements caused by asset condition deterioration, performance, wear and tear, actions of the elements, accidents and functional and technical obsolescence.

Foster Associates determined the hazard curves that describe the expected risk profiles for each of Hydro One's major asset groups, including transformers, circuit breakers, and conductors. These curves serve as the basis for estimating asset failure risks in the reliability risk model."

Interrogatory:

a) The above reference includes "retirements" as a Hazard Rate constituent component.
   i. Please define the term "retirements" as used in this reference.
   ii. Please describe the conditional failure mechanism associated with "retirements".

b) Please provide a copy of Foster Associates' 2014 Asset Failure Analysis report.

c) Are transformers, circuit breakers and conductors the only asset classes for which hazard curves were developed?

d) Has Hydro One historically retired individual assets or classes of assets at specified ages, regardless of asset condition, wear and tear, performance, etc.?
   i. If yes, how have Hydro One's retirement practices influenced the cited Hazard Rate curves?
   ii. If yes, how have Hydro One or Foster Associates adjusted the Hazard Rate curves to compensate for the different replacement methodologies that are applied to different assets?

e) In the determination of Hazard Rate curves, how are major failures differentiated from smaller or partial failures that can be easily repaired? For example, would the curves treat failure of a transformer bushing NEMA-pad connector differently than a transformer winding failure? Please explain.

f) For conductor failures, does the Hazard Rate curve differentiate failures caused by acts of God (e.g.: wind storm, ice storm) from failures caused by normal wear & tear or corrosion? Please explain.

g) Are the Hazard Rate curves consistent across all regions, or are different categories modified depending upon regional characteristics, e.g.: heavy ice loading areas, or high corrosion zones.

Response:

a) The term "retirements" refers to asset replacements due to planned end-of-life asset replacement or demand failures requiring replacement in the year in which they occurred. For example, a 55 year old end of life air-blast circuit breaker is replaced in 2016 with a new SF6 circuit breaker. Retirement of the air-blast circuit breaker is in year 55 and this would be incorporated and reflected in the Hazard Curves.

b) The report Foster Associates' 2014 Asset Failure Analysis report has been provided with this response as Attachment 1.

c) No. See the attached Foster Associates report for all asset classes that were covered. See Staff IR 17C

d) No, consistent with Exhibit I, Tab 1, Schedule 14, Part g) asset retirements are always carried out based on condition, performance, wear and tear, etc.

e) Failures in the context of Hazard Rates or curves refer to the fact that the asset was consequently removed from the system. Asset failures that can be repaired resulting in the asset returning to service are not reflected in the Hazard Curves whatsoever.

f) All asset removals are incorporated in the analysis whether they are due to acts of God, normal wear and tear, corrosion, manufacturers' defects, etc.

g) Hazard rates have been developed for the fleet of assets across the entire province. We have not regionalized the analysis.

Ontario Energy Board (Board Staff) INTERROGATORY Attachment 1

Hydro One has filed in confidence a report entitled '2014 Asset Failure Analysis' conducted by Foster Associates, Inc. The report presents a 2014 statistical analysis of physical and inspection failures observed in selected plant categories classified in Transmission Lines, Transmission Stations and Distribution Lines owned and operated by Hydro One. The report contains asset survival analysis and data proprietary to Hydro One. The study compares service life indications derived using the Iowa curve family with indications derived by Hydro One using the Weibull survival function. The scope of the investigation was limited to a statistical life analysis.

Ontario Energy Board (Board Staff) INTERROGATORY #021

Reference:

Exhibit B1/Tab2/Sch 4/ Attachment 1 – Section 5: Summary of Risk Model Assumptions, pg. 6

5. SUMMARY OF RISK MODEL ASSUMPTIONS

Asset	Critical Inputs and Assumptions		
	Demographics	**Hazard Curves**	**Units of activity under investment plan**
Transformers	Hydro One's transformer demographics as of Jan. 2016	• Hazard curves for each type of transformer (e.g. auto-transformer, step down transformer) were applied to the asset demographics of that type of transformer; calculated a weighted average to arrive at an asset-class level metric	• Oldest transformers were assumed to be prioritized for replacement according to proportion of total transformers beyond expected service life for each transformer type

Interrogatory:

a) Please confirm that the transformers proposed for replacement in this filing are actually the oldest transformers in the Hydro One fleet.

b) If not, please confirm that the calculation of reliability risk change is based upon the actual capital investment plans for replacing transformers rather than the assumption that the oldest transformers are being replaced. Please provide detailed calculations showing how the reliability risk calculations were modified to accommodate the actual replacement list.

c) Please identify which of the oldest transformers identified in Hydro One's Jan 2016 transformer demographics per the above reference are not proposed for replacement in this filing. Explain how Hydro One determined that these transformers did not require replacement.

Response:

a) No, not all transformers proposed for replacement in this filing are the oldest transformers in Hydro One's fleet. All transformers proposed for replacements are substantiated by asset need following the process described in Exhibit B1, Tab 2, Schedule 5. Please see Exhibit I, Tab 1, Schedule 31 for details of planned transformer replacements.

b) During the planning stage, the calculation of reliability risk is simplified by assuming the oldest unit associated with highest hazard rate will be replaced. At the end of each year, based on new transformer in-service information, the entire transformer fleet information will be updated. It is at this time that the true reliability risk will be reflected using the updated demographic profile. Since most of the proposed transformer replacements are older units and percent of replacement over total fleet is relatively small, this assumption is expected to create marginal errors in transformer reliability risk. From the perspective of using reliability risk as a directional indicator to help inform the appropriate capital investment level, this marginal error is acceptable. Hydro One does recognize this as an opportunity for improvement. The next iteration of reliability risk model will factor in the actual age of transformers proposed for replacement in the demographic profile to improve reliability risk calculation during planning stage.

c) The oldest transformers identified in Hydro One's Jan 2016 transformer demographics that are not proposed for replacement in 2017 and 2018 are listed below. In practice, the replacement candidates are not selected based on age but on the process discussed in Exhibit B1, Tab 2, Schedule 5.

	Station	**Transformer**	**Year Built**	**Rationale**
1	Coniston TS	T2	1940	To be decommissioned
2	Gage TS	T3	1942	Planned to replace in 2019
3	Gage TS	T6	1942	Planned to replace in 2019
4	Manitouwadge TS	T1	1945	Replaced in 2016
5	Algoma TS	T6	1948	Planned to replace in 2025
6	Carlton TS	T1	1948	To be decommissioned in 2021
7	Dobbin TS	T2	1948	Planned to replace in 2022
8	Elliot Lake TS	T2	1948	Planned to replace in 2024
9	Gage TS	T4	1948	Planned to replace in 2019
10	Gage TS	T5	1948	Planned to replace in 2019
11	Moose Lake TS	T2	1948	Planned to replace in 2022
12	Nelson TS	T1	1948	Planned to replace in 2019
13	Nelson TS	T2	1948	Planned to replace in 2019

	Station	**Transformer**	**Year Built**	**Rationale**
14	Timmins TS	T63	1948	Decommissioned 2016
15	Moose Lake TS	T3	1948	Planned to replace in 2022
16	Coniston TS	T3	1949	To be decommissioned
17	Kirkland Lake TS	T13	1950	In-servicing in 2017, legacy of Transformer Replacement Program
18	Otto Holden TS	T3	1950	Planned to replace in 2025
19	Dobbin TS	T5	1951	Planned to replace in 2022
20	Espanola TS	T1	1951	Replaced in 2016
21	Espanola TS	T2	1951	Replaced in 2016
22	Glendale TS	T3	1951	Planned to replace in 2021
23	Glendale TS	T4	1951	Planned to replace in 2021
24	Keith TS	T11	1951	Planned to replace in 2022
25	Kingsville TS	T4	1951	Planned to replace in 2021
26	Kirkland Lake TS	T12	1951	In-servicing in 2017, legacy of Transformer Replacement Program
27	Tilbury TS	T1	1951	To be decommissioned
28	Kingsville TS	T2	1952	Planned to replace in 2021

Ontario Energy Board (Board Staff) INTERROGATORY #022

Reference:

Exhibit B1/Tab2/Sch 4/ Attachment 1 – Section 5: Summary of Risk Model Assumptions, pg. 6

5. SUMMARY OF RISK MODEL ASSUMPTIONS

Asset	Critical Inputs and Assumptions		
	Demographics	**Hazard Curves**	**Units of activity under investment plan**
Conductors	All asset demographics in circuit kilometers Conductor asset demographics as of Jan 2016	• Hydro One's lines demographics extended beyond the age (90) at which the hazard curve for conductors reached a limit of 4.6%. • Assumption built into model of 1% increase in risk for every year of aging past 90 in order to more realistically represent the risk facing aging conductors	• Oldest conductors assumed to be replaced first

Interrogatory:

a) Has Hydro One quantified the relationship between conductor failures and asset age?

b) Does "risk" as used in the table above mean "annual probability of failure"?

c) Please show the calculations used by Hydro One to support the assumed 1% increase in "risk" (or annual probability of failure) for each year of aging past 90.

d) Please show the quantified relationship between Hydro One's conductor fleet demographics and annual conductor failures over the last 10 years.

e) Does Hydro One include failures caused by hardware such as sleeves, saddles, dead-ends and spacer-dampers in its count of conductor failures?

   i. If yes, is Hydro One able to separate hardware failures from actual conductor failures? Please provide the relevant data for the past 10 years.

   ii. Is conductor replacement the most economically efficient approach to reducing the frequency of hardware failures?

f) Please confirm that Hydro One's calculation of reliability risk change is based upon actual capital investment plans (for replacing conductors) rather than the assumption that the oldest conductors will be replaced. Please explain in detail.

g) Please confirm that the actual list of conductors being proposed for replacement comprises the oldest conductors, and if not, please identify how the actual list was developed.

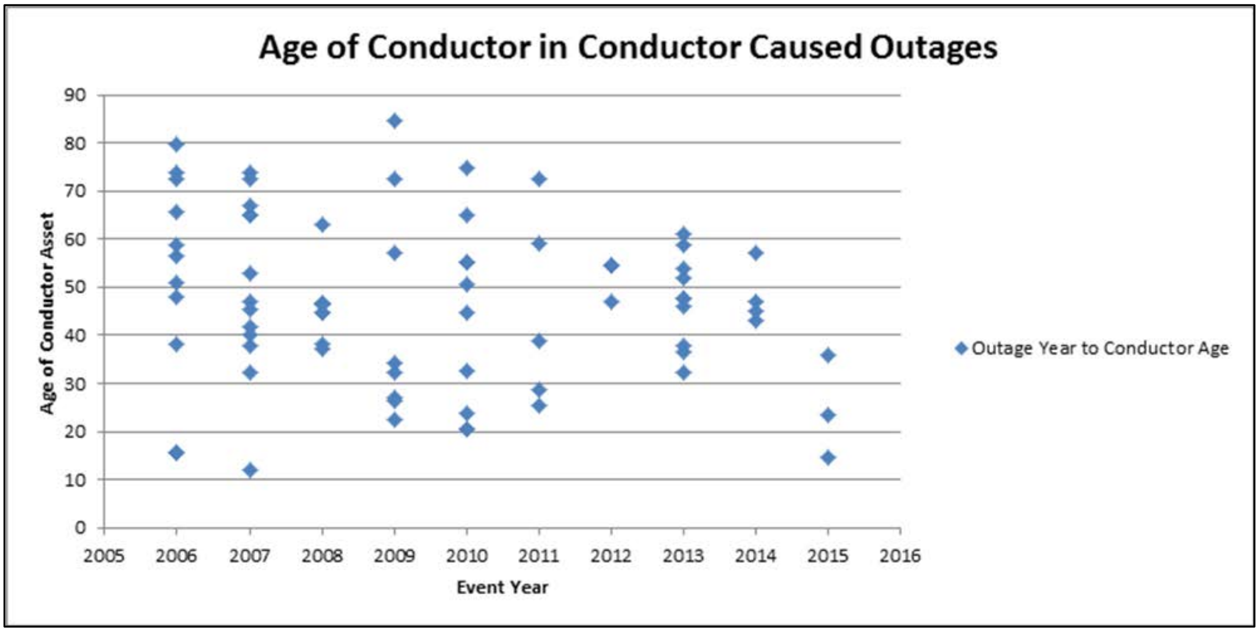
Response:

a) Yes, through hazard rate analysis, based on Hydro One historical data. Please refer to Exhibit I, Tab 1, Schedule 20, Part b).

b) The "risk" in the table above represents the annual probability of failure in the year, given that the asset has survived through the previous years.

c) The 1% increase in risk for every year of aging past 90 was considered and rejected during development of the reliability risk model. The reference in Attachment 1 – Section 5: Summary of Risk Model Assumptions was referenced in error. Instead the actual conductor hazard curve based on the 2014 Foster Associates Report was applied.

d) Within Ontario, the relationship between conductor failure and demographic is not linear because weather loading is a key contributing factor. An aged conductor will experience deterioration in strength and ductility, failure will occur when weather loading exceeds its remaining capability. Conductor failure is an adverse event that is dependent upon two factors, weather loading and integrity of asset. Weather events are unpredictable, hence the only controllable factor is to ensure asset integrity. Therefore, conductor fleet management approach is to replace aged and deteriorated conductor, verified by actual laboratory test results, to ensure safety and maintain reliability.



e) Yes, While Hydro One includes all failures that led to line drops as line failures, failure causes are tracked separately.

i) Sleeves and dead-end connectors are considered as part of conductor system; as such they are included in conductor failure statistics. Hardware such as u-bolts and suspension clamps are tracked separately. Please see the table below for hardware failures in the past 10 years.

OUTDATE	AGE
5/21/2006	50
6/1/2006	73
6/15/2007	59
1/2/2009	57
3/29/2009	38
3/29/2009	75
3/29/2009	73
2/16/2011	35
2/29/2012	59
7/11/2012	66
7/11/2012	66
10/9/2012	40
1/23/2013	61

ii) Design life for conductor hardware (except u-bolt and dampers) meets or exceeds the life of a conductor. Therefore, there is no need to replace the conductor hardware prior to conductor replacement. All Hydro One line refurbishment projects are driven by deterioration of conductors and when this occurs all conductor hardware will be replaced.

U-bolts and dampers will wear out before conductors reach end of life. There are separate investments targeting line hardware component replacements prior to conductor reaching end of life.

In summary, for well designed and constructed lines, complete line refurbishment is the most economical approach to reduce the hardware failure frequency, restore asset integrity, mitigate safety hazard and maintain reliability.

f) Please refer to Staff IR 21.a and b. Similar to transformer reliability risk modeling, an assumption is made to simplify reliability risk calculation where oldest conductors are assumed to be the replacement candidates during planning stage. In practice, conductor replacement candidates are chosen based on laboratory verification of asset condition. Although there is a high degree of correlation between conductor age and condition, not all chosen replacement candidates are the oldest conductors.

g) The proposed conductor replacement candidates described in Investment Summary Document S63, S64, S66, S67, S68, S69, S70, S71, S72, S73 and S74, are based on actual conductor samples removed from the respective lines and end of life condition validated via laboratory testing.

Ontario Energy Board (Board Staff) INTERROGATORY #023

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1: Asset Risk Assessment Methodology, pg. 2

"In assessing asset needs, planners also consider other factors such as environmental risks and requirements, compliance obligations, equipment defects, health and safety considerations and customer needs and preferences. Planners then make recommendations regarding what investments should be made within an identified timeframe. To clarify, the ARA is one step in the asset planning process; it does not replace decisions made by qualified engineers in conjunction with physical inspections."

Interrogatory:

a) Is the ARA a screening tool used by Hydro One to determine the overall portfolio of potential sustainment projects considered for inclusion in the capital budget, with the final selection made by qualified engineers?

b) Were all the projects included in the present filing initially identified using the ARA?

c) Were any projects initially identified using a different methodology? If yes, please specify which projects and which methodology was used.

d) Were any projects in the present filing directly selected using only the ARA methodology?

e) Please explain why the asset information is not consolidated into one system in order to enable decisions based upon a comprehensive algorithm (e.g.: why aren't the physical inspection results incorporated into the ARA to evaluate and compare the risks per asset)?

Response:

a) The Asset Risk Assessment methodology ("ARA") is an assessment *process* used by qualified engineers to develop an overall portfolio of potential Sustainment investments, which are subject to the investment optimization process described in Exhibit B1, Tab 2, Schedule 7.

b) The ARA methodology was used to identify all Sustainment capital projects reflected in Hydro One's current application.

c) No Sustainment capital projects reflected in Hydro One's current application were identified using a different methodology.

d) Investments were directly selected using only the ARA methodology if they addressed negative health and safety impacts or were required to meet regulatory and government policy requirements, as these are considered non-discretionary.

e) Hydro One maintains a database of asset information in its Asset Analytics tool, but more than asset information is required to determine investment decisions. There are external factors that asset planners consider when exercising engineering analysis and judgment to formulate an investment recommendation, such as customer needs and preferences, outage implications, site accessibility, safe working clearance, and work bundling. Moreover, at this point, it is not possible to incorporate all relevant information into a single algorithm to enable better decision-making. Professional judgment is still required.

Physical inspections are required to verify and contextualize desktop assessments of asset needs and to determine field conditions and requirements. These inspections yield project-level findings and constraints, whereas Hydro One's Asset Analytics tool focuses on asset-level risk factors. Examples of project-level findings and constraints include limited working space and staging area, access challenges, proximity to environmentally sensitive areas, various local conditions and outage constraints. It is impractical to incorporate these types of project-level findings and constraints into an asset-focused algorithm. For this reason, physical inspection results are incorporated used in the ARA process, but not an algorithm.

Ontario Energy Board (Board Staff) INTERROGATORY #024

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1.2: Asset Demographic Risk, pg. 3

"Asset demographic risk relates to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage, which is based on empirical data. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages. Assets with relatively high demographic risk are candidates for refurbishment or replacement."

Interrogatory:

a) Does "asset demographic risk" as used above mean the correlation between the probability of failure and the "make, manufacturer, and/or vintage" of different classes of assets?

b) Has Hydro One developed annual probabilities of failure for different asset classes based upon asset make, manufacturer and age? If yes, please provide details of the methodology used to develop these probabilities and the resulting annual failure probabilities for all asset classes based on make, manufacturer and age.

c) Was "asset demographic risk" the primary criterion used to select any of the projects listed in this filing? If yes, please identify those capital projects and provide details of how this methodology was used in their selection.

Response:

a) "Asset demographic risk" is the correlation between the current age of an asset and the expected service life (ESL) of the asset class. The ESL of major asset classes is defined in Exhibit B1, Tab 2, Schedule 6.

b) Hydro One has developed probabilities of failure for different asset classes and age. Please refer to the Foster Associates, Inc. report "2014 Asset Failure Analysis" for a description of the methodology and failure probabilities. Please refer to Exhibit I, Tab 1, Schedule 20, Part b).

c) "Asset demographic risk" was not the primary criterion used to select any of the projects listed in Hydro One's current application. The methodology used to identify investment candidates is described in Exhibit B1, Tab 2, Schedule 5.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #025

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1.3: Asset Criticality, pg. 3

"Asset criticality represents the impact that the failure of a specific asset would have on the transmission system. Primarily, it is used to show relative importance of an asset compared to other assets of the same type."

Interrogatory:

a) How does Hydro One evaluate Asset Criticality for individual assets? Please explain in detail, including discussion of the role that probability of failure and consequence of failure play in determining Asset Criticality.

b) How does Hydro One quantify Asset Criticality (i.e.: is it represented as a number, such as 1 to 10, or is it assigned a subjective description, like very important and less important)?

c) Please confirm that Asset Criticality is used by Hydro One to evaluate the consequence of failure of specific assets.

d) Please provide a listing of the 10 highest criticality assets in Hydro One's fleet as evaluated using this methodology, and provide details of how criticality was determined for each asset.

Response:

a) Criticality determines the importance of an individual asset. An asset's criticality score is a function of the consequence of its failure. Asset criticality scores are a means of determining the most critical asset within a specified asset class. Probability of failure has no influence on the criticality of an asset. Probability of failure is a function of asset condition and performance while asset criticality is a function of the asset's specifications, configuration in the system and customer impact.

For each asset type, there are supporting factors used to calculate the asset's criticality. Each of these supporting factors will have a score based on the characteristics or configuration of that individual asset. These supporting factors are then assigned a weighted percentage value which is used as the basis for the criticality score. Typical supporting factors used in determining criticality scores are voltage rating, MVA rating, whether there is a single point of vulnerability, and whether the asset is part of, or associated with, system elements that have been designated for regulatory oversight by reliability organizations such as NPCC, NERC and the IESO.

b) Asset criticality is scored on a scale of 1 to 100 where 100 is the most critical.

c) This is confirmed.

d) Criticality is calculated differently for each asset type (e.g. transformers, breakers, etc.), and the criticality score can only be used to compare criticality of an asset within its asset type. Hydro One has divided its assets into 18 different asset types. The following table shows the top 10 highest criticality scores in the transformer asset type.

Transformers: Top 10 Criticality Scores

Transformer	Criticality Score
Cherrywood TS T14	88
Cherrywood TS T15	88
Cherrywood TS T16	88
Cherrywood TS T17	88
Keith TS PSR5	87
Bruce A TS T25	82
Bruce A TS T27	82
Bruce A TS T28	82
St Lawrence TS PS33	78
St Lawrence TS PSR34	78

An asset's total criticality score is calculated using a formula which incorporates the importance of: (i) the station; (ii) class of asset (e.g. autotransformer or step-down); and (iii) the individual asset score. Below are lists of factors which contribute to the importance of a station and an asset class.

(i) <u>Station Importance – Supporting Factors – (Available Selections)</u>

- Station Voltage Rating – (>300kV, >150kV, > 75kV)
- Identified as a Bulk Power System Station (BPS) – (Y/N)
- Included in the Basic Minimum Power System (BMPS) – (Y/N)
- Considered a Mission Critical Station – (Tier 1, Tier 2, No)
- Critical Customer List – (Y/N)

- Generation Supply – (>1500MVA, >1000MVA, >500MVA, >100MVA, <100MVA)
- Total Customer Load – (>200MW, >150MW, >100MW, >50MW, <50MW)
- Total Station Power Flow – (>1500MVA, >1000MVA, >500MVA, >100MVA, <100MVA)

(ii) Asset Importance – Supporting Factors – (Available Selections)

- Voltage Rating – (>300kV, >150kV, > 75kV)
- MVA Rating – (>500MVA, >300MVA, >150MVA, >100MVA, <100MVA)
- Single Point Vulnerability – (Y/N)

Ontario Energy Board (Board Staff) INTERROGATORY #026

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1.4: Asset Performance Risk, pg. 3

"Asset performance risk reflects the historical performance of an asset, which is based on empirical data. Performance is defined by any power interruptions that have been caused by failure of the asset. This risk factor considers the frequency and duration of these interruptions, as well as whether the interruptions are occurring more or less frequently over time."

Interrogatory:

a) Does Hydro One examine the correlation between its Asset Condition Assessments and subsequent Asset Performance? In other words, how often do assets that initially receive a positive Asset Condition Assessment subsequently perform poorly, and vice versa?

b) Please identify any asset replacement projects listed in this filing for which "Asset Performance Risk" was the primary driver for the asset replacement decision?

c) Does Hydro One track Asset Performance Risk by individual asset or by groups or classes of assets?

Response:

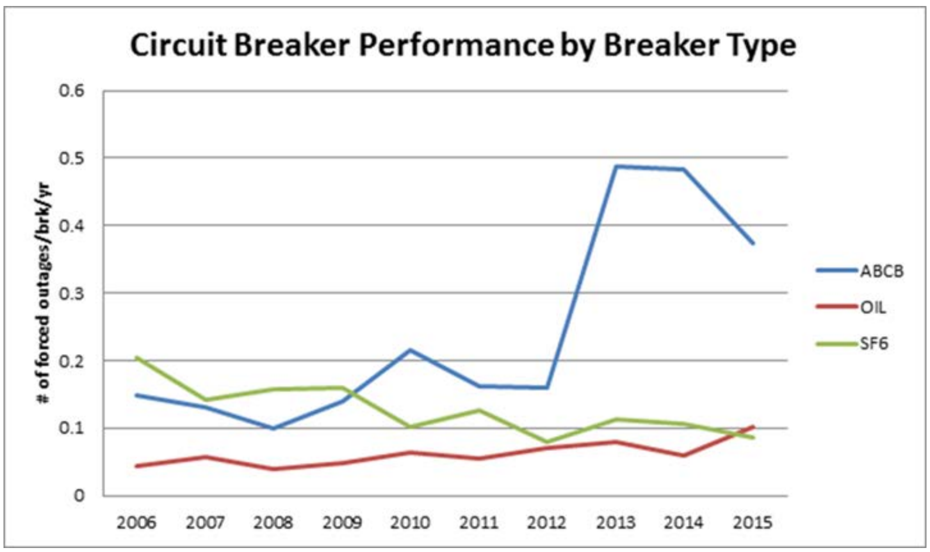
a) Hydro One examines the interplay between all risk factors, including condition and performance. For performance, Hydro One looks at the frequency of outages, the duration of outages and whether the trend in outages in worsening. Generally, where condition is poor, performance is also poor. However, there are cases where this is not true. There are also cases where an asset's performance is poor, but condition is good.

To illustrate, Hydro One has observed that the erroneous operation of a transformer's auxiliary relay may cause an increase in frequency of outages. In such instances, the underlying asset was still in good condition, but its auxiliary relay was faulty. Rather than condition, performance was used to identify and remedy the problem.

It is also possible to have an asset in poor condition with a high probability of failure that does not show any signs of performance issues until the day it fails. In such cases, performance will be good until the day the asset fails.

b) Air-blast circuit breaker performance is about four to five times worse than oil and SF6 circuit breakers. The condition of these breakers and their associated high pressure air systems have deteriorated to the point that they are at end-of-life, causing major impacts to system reliability and interruptions for Hydro One's customers. For this reason, performance is considered the primary driver for many of the air-blast circuit breaker replacement projects.

c) Hydro One tracks asset performance risk of individual assets and by groups or classes of assets. For example, Figure 10 in Exhibit B1, Tab 2, Schedule 6 (which is reproduced below) shows performance by circuit breaker type, indicating that air-blast circuit breaker performance is about four to five times worse than oil and SF6 breakers.



Ontario Energy Board (Board Staff) INTERROGATORY #027

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1.5: Asset Utilization Risk, pg. 4

"Asset utilization risk represents the increased rate of deterioration exhibited by an asset that is highly utilized, which is based on empirical data. The relative deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate more quickly than those that are lightly loaded."

Interrogatory:

a) Please identify any asset replacement projects listed in this filing for which "Asset Utilization Risk" was the primary driver for the asset replacement decision.

b) Please show how Hydro One evaluated asset utilization risk for a specific representative project.

c) Does Hydro One track asset utilization for all its assets or only for assets of specific sizes and classes?

d) Please provide a listing of the 10 most heavily utilized assets for each of the following classes:

- Autotransformers;
- Transformers;
- Air-blast Circuit Breakers;
- Oil Circuit Breakers;
- 500 kV Transmission Lines;
- 230 kV Transmission Lines; and
- 115 kV Transmission Lines.

e) Please identify which, if any, of the assets listed in d) are scheduled for replacement in Test Years 2017 & 2018.

f) Does Hydro One track the historic loadings of its transformers? If yes, please explain how this information is incorporated into the asset utilization risk evaluation and provide concrete examples of how the information is utilized.

Response:

a) Asset utilization risk is not the primary driver for asset replacement decisions for projects set out in this filing. Projects listed in this filing are selected based on the multi-faceted asset risk assessment process described in Exhibit B1, Tab 2, Schedule 5.

b) Asset utilization risk is evaluated on a per asset basis. In the case of the Bruce A TS ABCB project (detailed in Exhibit B1, Tab 3 Schedule 11, Investment Summary Document #S03), the existing air blast circuit breaker cannot meet system short circuit requirements.

c) Hydro One tracks asset utilization only for specific assets and asset classes.

d) The following are the 10 most heavily used assets for the specified asset classes:

	Station Assets			
	Autotransformers	**Transformers**	**Air-blast Circuit Breakers**	**Oil Circuit Breakers**
1	Otto Holden TS T3	Manby TS T6	Richview TS L19L22	Dundas TS M5
2	Otto Holden TS T4	Manby TS T5	Richview TS A2L19	Goderich TS M2
3	Trafalgar TS T15	Manby TS T3	Middleport TS L27L39	Dundas TS M2
4	Trafalgar TS T14	Slater TS T1	Richview TS H1L4	Wilson TS M11
5	Claireville TS T13	Kingsville TS T1	Richview TS L4L74	Norfolk TS M3
6	Claireville TS T15	Kingsville TS T4	Richview TS H1L79	Belleville TS BY
7	Claireville TS T14	Overbrook TS T3	Richview TS A1L74	Sheppard TS M4
8	Hanmer TS T9	Manby TS T4	Richview TS H2L22	Palermo TS M1
9	Claireville TS T16	Kingsville TS T2	Richview TS L24L72	Dundas TS M3
10	Hawthorne TS T6	Red Lake TS T3	Richview TS A2L73	Leslie TS M2

Hydro One does not track asset utilization for transmission lines as it does not inform or drive asset replacement decisions.

The following table identifies circuit sections which exhibited the highest percentage line loading on the highest Ontario System Peak Demand day in 2016, August 10. The listing is a reflection of system conditions at the time, including outages and weather conditions and does not provide correlation to the long term loading levels of each of the circuits.

#	Transmission Lines		
	500 kV	**230 kV**	**115 kV**
1	P502X (Porcupine TS x Hanmer TS)	M31A (Ellwood MTS x Hawthorne TS)	S7M (Fallowfield MTS x Fallowfield JCT)
2	D501P (Pinard TS x Porcupine TS)	M30A (Ellwood MTS x Hawthorne TS)	H2JK (Don Fleet JCT x Esplande TS)
3	X504E (Hanmer TS x Nobel SS)	B5D (IPB Baudet JCT x St. Isidore TS)	H2JK (Don Fleet JCT x Basin TS)
4	B561M (Bruce JCT x Bruce B SS)	L24A (Hawthorne TS x Raisin River JCT)	S7M (STR R14-R15 JCT x Fallowfield JCT)
5	M570V (Clairville TS x Milton SS)	P15C (Cherrywood TS x Dobbin TS)	S7M (STR 673N JCT x STR R14-R15 JCT)
6	M571V (Clairville TS x Milton SS)	D5A (Cumberland JCT x St. Isidore TS)	L13W (Bridgman JCT x Balfour JCT)
7	B561M (Milton SS x Willow Creek JCT)	Q24HM (Beck #2 TS x Hannon JCT)	J3E (Crawford JCT x Keith TS)
8	B504C (Bowmanville SS x Cherrywood TS)	L24A (Raisin River JCT x St. Lawrence TS)	J4E (Crawford JCT x Essex TS)
9	B541C (Bowmanville SS x Cherrywood TS)	Q29HM (Beck #2 TS x Hannon JCT)	J4E (Crawford JCT x Keith TS)
10	B501M (Willow Creek JCT x Milton SS)	Q23BM (Beck #2 TS x Niagara West JCT)	L2M (Limebank JCT x Merivale TS)

e) The following assets listed in d) above are scheduled for replacement in 2017 or 2018:

a. Autotransformers
- *None*

b. Transformers
- Overbrook TS T3

c. Air-Blast Circuit Breakers
- *None*

d. Oil Circuit Breakers
- Goderich TS M2

e. 500 kV Transmission Lines
- *None*

f. 230 kV Transmission Lines

- *None*

g. 115 kV Transmission Lines
   - *None*

f) Hydro One does track the historic loading of its transformers. Asset utilization risk takes into account peak loading of the transformer compared to the transformer capacity. Hydro One operates transformers within their operating specifications and limits. Historical loading information is reviewed when considering a transformer for replacement.

Ontario Energy Board (Board Staff) INTERROGATORY #028

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1.6: Asset Economic Risk, pg. 4

"Asset economic risk is based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the present value of ongoing maintenance to that of complete refurbishment or replacement.

While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement."

Interrogatory:

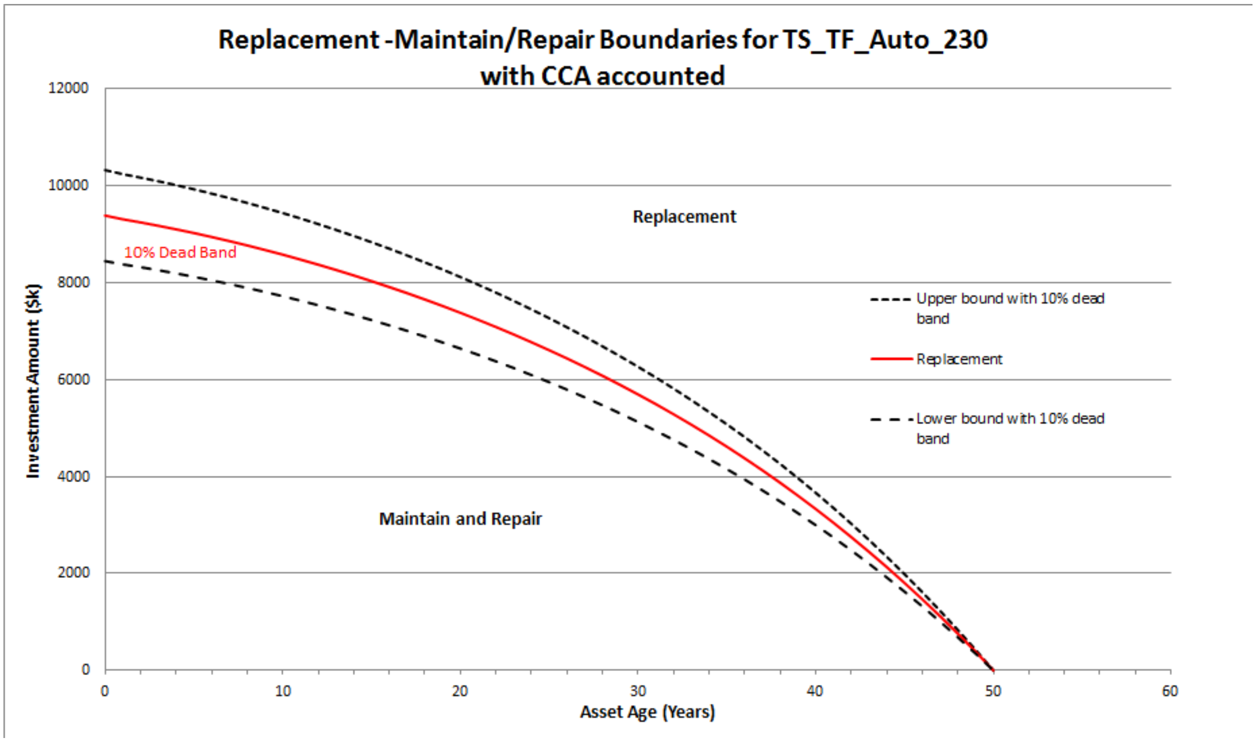
a) Does Hydro One develop business cases to evaluate the all-in economic risk of individual assets or groups of assets (such as integrated substation investment projects) when preparing its capital budgets, and when determining if the economic risk of an asset or group of assets would be most economically addressed by replacement or refurbishment?
   i. If yes, does the business case evaluation criteria change in accordance with a certain materiality threshold? Please provide details.
   ii. If yes, please provide the business cases for all projects listed in this filing with total costs of over $20M.
   iii. If no, please explain why Hydro One does not develop business cases to evaluate capital investments of this magnitude, and describe the cost materiality threshold at which developing a business case would be considered appropriate.
   iv. If no, please provide details of how the all-in economic risk is measured and analyzed.

b) How does Hydro One evaluate the economic risk of a refurbished asset prematurely failing when deciding between replacement and refurbishment for a particular asset?

Response:

a) Yes, Hydro One evaluates the economic risk of replacing or refurbishing assets or groups of assets when developing business cases.

   i. Only major assets such as transformers, breakers and transmission lines are economically evaluated to determine if they should be replaced or refurbished. See the graph below for a sample economic analysis of a 230kV autotransformer.



ii. Please see the requested information in the Investment Summary Documents in Exhibit B1, Tab 3, Schedule 11.

iii. Not applicable.

b) Please see the graph above. When deciding between refurbishing or replacing an asset, Hydro One will consider the life extension associated with refurbishment by performing an economic sensitivity analysis (i.e. net present value analysis) on the extension.

Ontario Energy Board (Board Staff) INTERROGATORY #029

Reference:

Ref: Exhibit B1/Tab2/Sch 5/ – Section 2.2: ARA Data, p. 5

"Asset condition data is collected during routine maintenance, inspections and testing. For each specific asset, information on condition, performance history, utilization, criticality and other non-condition characteristics is compiled into a database for planning purposes. Improving the quality and quantity of this data is an ongoing objective for Hydro One."

Interrogatory:

a) What steps does Hydro One take to ensure the consistency of the asset condition data? In other words, how does Hydro One ensure that the assessment of "asset condition" is consistent across the system, and across the spectrum of employees making the assessments?

b) Does Hydro One track the predictive accuracy of the results produced by its ARA process? If yes, please provide details.

c) Is the existing ARA database complete enough and the evaluation methodology robust enough that it appropriately prioritizes capital expenditures without human intervention post-processing?
   i. If not, when does Hydro One expect that ongoing investments in this system will produce reliable project prioritization results?
   ii. Please provide the expected schedule and costs of the ARA implementation plan for achieving this outcome.

d) What are the historical and forecast annual OM&A and capital costs of developing, operating and maintaining Hydro One's Reliability Risk Model from its initiation to 2021?

Response:

a) To ensure consistency in asset condition data, standardized electronic data collection templates are used to collect asset condition data during maintenance activities for synchronization into the SAP system of record. They have drop-down lists with predetermined values and numerical value validation to ensure data quality. The assessment of this asset condition data is then carried out using the Asset Analytics software tool to ensure consistency of the assessments across the entire province.

b) The ARA is not a predictive tool. It is a process that is used to inform investment decisions as described in Exhibit B1, Tab 2, Schedule 5. The investment proposals made using the ARA process are submitted into the investment optimization process described in Exhibit B1, Tab 2, Schedule 7.

c) The ARA is a process or approach, not a database. It should not be confused with the Asset Analytics software tool, which planners use when going through the ARA process. As such, the ARA will always involve engineering analysis and judgment because it is only a process planners use. The ARA process does not compare or prioritize investments. Hydro One uses the AIP software described in Exhibit B1, Tab 2, Schedule 7 to prioritize investments.

(i) Hydro One does not expect to ever use the ARA process to prioritize investments for the reasons described above.

(ii) There is no implementation plan or schedule for ARA because it is only a process that Hydro One's planners use, not a technology or business process solution.

d) The Reliability Risk model, as outlined in Attachment 1 of Exhibit B1, Tab 2, Schedule 4, is new to Hydro One. It relies on asset demographic profiles and hazard rates to quantify risk. The OM&A and capital costs of developing, operating and maintaining this model are negligible.

Ontario Energy Board (Board Staff) INTERROGATORY #030

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.1.1: Transformers - Asset Overview, pg. 3

"The forced outage frequency of transformers has been relatively stable over the last decade. However, transformer failures can have a significant impact to local and system reliability. Transformers failures also have a negative impact on the environment in the event of oil spills."

Interrogatory:

a) Does Hydro One correlate its transformer failures against the results of its diagnostic testing and/or its transformer fleet demographics?

b) If yes, please provide the results of this analysis covering the past 10 years.

c) If no, please explain how Hydro One utilizes fleet demographics and diagnostic testing results in evaluating reliability risk and initiating asset replacement projects for its transformers.

Response:

a) Yes, Hydro One correlates its transformer failures against the results of its diagnostics testing results and its transformer fleet demographics. As a standard practice, Hydro One performs an asset event investigation after a major asset fails.

b) Provided below is a list of the failed power transformers 2006-2015 on which Hydro One performed the major asset investigations:

-Pinard T1 Failure Investigation Report 2006
-Porcupine T8 Failure Investigation Report 2009
-Essa T3 (Blue Phase) Failure Investigation Report 2010
-Richview T7 and T8 Failure Investigation Report 2011
-Hanmer T6 (White Phase) Failure Investigation Report 2012
-Brant T2 Failure Investigation Report 2013
-Hanmer T9 (Blue Phase) Explosive Failure of Bushing Report 2015

c) N/A

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #031

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.1.1: Transformers - Asset Overview, pp. 2-3

"Hydro One has 721 large transmission class transformers in service.

- *Currently 28% of the transformer population is beyond its expected service life.*
- *The condition of the transformer fleet, determined through industry standard diagnostic testing, is such that 15% present high or very high condition risks that need to be mitigated.*

Given the demographics of the transformer population, the condition trend and the risks associated with transformer failures including reliability impact, environmental and safety concerns, Hydro One plans to replace 27 transformers in 2017 and 22 in 2018. Regulatory requirements related to oil leaks, noise levels and PCB contaminated oil in equipment also contribute to the need to replace some of the transformer fleet."

Interrogatory:

a) Please provide a list of all 49 transformers selected for replacement in 2017 and 2018.

b) Please categorize each of the selected transformers by the primary driver for replacement: e.g.: high probability of failure, severe consequence of failure, noise levels, leaks, PCB contamination or other (if "other", please specify).

c) Hydro One has stated that 15% of its transformer fleet (i.e.: 108/721) exhibits "high or very high condition risks".
   i. Are all "high or very high condition risks" best addressed with transformer replacement?
   ii. Can any of the "high or very high condition risks" associated with transformers be successfully mitigated through refurbishment?

d) Please separately quantify the number of Hydro One transformers classified as exhibiting "high condition risks" and "very high condition risks".

e) Please identify which of the 49 transformers scheduled for replacement in 2017 & 2018 have been classified as exhibiting "high or very high condition risks".

f) Does Hydro One intend to replace all 108 transformers classified as exhibiting "high or very high condition risks" over the period 2017 to 2021?

g) Are all transformers classified as exhibiting "high or very high condition risks" included in the 28% of transformers categorized as being beyond expected service life? Please identify all exceptions.

Response:

a) Please refer to Table 1 below.

b) Please refer to Table 1 below.

In 2017 and 2018 the number of planned replacement units is 41 with 4 demand replacement per year, totalling to 49 units. The table below provides the transformer and primary driver for replacement.

Table 1: List of planned Transformer replacement between 2017-2018

I/S Year	Location , Opdes	Primary Driver based on Detail Transformer Assessment
2017	Aylmer T2	EOL confirmed by dissolved gas analysis
2017	Aylmer T3	EOL confirmed by dissolved gas analysis
2017	Cecil T1	EOL confirmed by dissolved gas analysis
2017	Chenaux T3	EOL confirmed by insulation deterioration
2017	Chenaux T4	EOL confirmed by insulation deterioration
2017	Crawford T3	High maintenance and re-configuration
2017	Dryden T1	EOL confirmed by insulation deterioration
2017	Dryden T2	EOL confirmed by insulation deterioration
2017	Dryden T3	EOL confirmed by insulation deterioration
2017	Earfalls T5	EOL confirmed by insulation deterioration
2017	Earfalls T5SP	EOL and re-configuration
2017	Goderich T1	Station re-configuration
2017	Goderich T2	EOL confirmed by insulation deterioration
2017	Goderich T3	EOL confirmed by insulation deterioration
2017	NRC T1	EOL confirmed by insulation deterioration
2017	NRC T3	EOL confirmed by insulation deterioration
2017	Overbrook T2	Customer commitment
2017	Overbrook T3	EOL confirmed by insulation deterioration
2017	Richview T1	EOL confirmed by dissolved gas analysis
2017	Richview T2	EOL confirmed by dissolved gas analysis
2017	St. Isidore T3	EOL confirmed by dissolved gas analysis
2017	St. Isidore T4	EOL confirmed by dissolved gas analysis
2017	Strathroy T1	EOL confirmed by dissolved gas analysis
2018	Allanburg T1	Capacity limiting
2018	Centralia T1	EOL confirmed by insulation deterioration

I/S Year	Location , Opdes	Primary Driver based on Detail Transformer Assessment
2018	Centralia T2	EOL confirmed by insulation deterioration
2018	Centralia T3	EOL confirmed by insulation deterioration
2018	Horning T1	Obsolete components, high maintenance
2018	Horning T2	Obsolete components, high maintenance
2018	Kenilworth T1	EOL confirmed by dissolved gas analysis
2018	Kenilworth T3	EOL confirmed by dissolved gas analysis
2018	Palmerston T1	EOL confirmed by dissolved gas analysis
2018	Palmerston T2	Station re-configuration
2018	Palmerston T3	EOL confirmed by dissolved gas analysis
2018	Stewartville T6	EOL confirmed by insulation deterioration
2018	Strachan T12	EOL confirmed by dissolved gas analysis
2018	*St. Thomas T1	Station to be decommissioned (*removal only)
2018	*St. Thomas T2	Station to be decommissioned (*removal only)
2018	Wanstead T1	EOL confirmed by dissolved gas analysis
2018	Wanstead T2	Station re-configuration
2018	Wanstead T3	EOL confirmed by dissolved gas analysis

c) Hydro One use Asset Analytics (AA) to perform transformer condition screening at the fleet level. Hydro One performs a detailed assessment to confirm the condition of these transformers, taking into account other factors as described in ARA process, Exhibit B1, Tab 2, Schedule 5, to inform investment decisions.

i) Transformers that are categorized as "high or very high condition risks" suggest a higher probability of failure due to non-repairable situations such as insulation degradation or internal fault which are best addressed with transformer replacement.

ii) Yes. For transformers that are classified as high or very high condition risk, Hydro One conducts comprehensive assessment to identify the best alternative (refurbishment or replacement). The decision of whether or not to refurbish a transformer is a trade-off among economics, scope of work, available expertise and timing. Based on the assessment, Hydro One selects the best alternative.

d) The number of Hydro One transformers classified as exhibiting "high condition risks" and "very high condition risks" is 97 and 14, respectively. Total is 111, which is 15.4% of the fleet.

e)

#	I/S Year	Location, Opdes	Condition
1	2017	Cecil T1	High Risk
2	2017	Chenaux T3	High Risk
3	2017	Chenaux T4	High Risk
4	2017	Goderich T3	High Risk
5	2017	N.R.C. T1	High Risk
6	2017	N.R.C. T3	High Risk
7	2017	Overbrook T3	High Risk
8	2017	Richview T1	High Risk
9	2017	Richview T2	High Risk
10	2017	St. Isidore T3	Very High Risk
11	2017	St. Isidore T4	High Risk
12	2017	Strathroy T1	High Risk
13	2018	Centralia T1	High Risk
14	2018	Centralia T2	High Risk
15	2018	Centralia T3	High Risk
16	2018	Kenilworth T3	Very High Risk
17	2018	Palmerston T1	High Risk
18	2018	Palmerston T3	High Risk
19	2018	Strachan T12	High Risk
20	2018	St. Thomas T1	Very High Risk
21	2018	St. Thomas T2	Very High Risk
22	2018	Wanstead T3	High Risk

f) Hydro One will perform detailed assessments of transformers classified as exhibiting "high or very high condition risks", taking into account other factors as described in ARA process, Exhibit B1, Tab 2, Schedule 5, to verify replacement is warranted. Once confirmed, these investment candidates will be prioritized in accordance with Hydro One investment planning process.

g) No as Expected Service Life only depends on age while condition assessment takes into account other factors. Below is a list of "high or very high condition risk" transformers that are not beyond Expected Service Life.

1	Beach TS	T6
2	Belleville TS	T1
3	Birch TS	T2
4	Birch TS	T4
5	Bramalea TS	T4
6	Caledonia TS	T1
7	Cedar TS	T2
8	Cedar TS	T8
9	Clarke TS	T4
10	Crawford TS	T4
11	Dufferin TS	T4
12	Elgin TS	T3
13	Elgin TS	T4
14	Fairbank TS	T1
15	Fairbank TS	T2
16	Hanlon TS	T1
17	Hawthorne TS	T7
18	Keith TS	T1
19	Kingsville TS	T1
20	Lambton TS	T5
21	Lauzon TS	T6
22	Lindsay TS	T1
23	Manby TS	T13
24	Manby TS	T14
25	Nelson TS	T4
26	Nepean TS	T3
27	Parry Sound TS	T1
28	Runnymede TS	T3
29	South March TS	T2
30	St.Andrews TS	T4
31	Stirton TS	T3
32	St.Isidore TS	T3
33	St.Isidore TS	T4
34	Walker TS #1	T13
35	Wilson TS	T1
36	Wonderland TS	T5

Ontario Energy Board (Board Staff) INTERROGATORY #032

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.1.3: Transformers - Asset Assessment Details, Demographics, pp. 4-5

"The average age of the transformer fleet is currently 34 years of age and 28% of the in service transformers are currently beyond their expected service life. The demographics of the transformer population are outlined in Figure 2.
The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through continued capital replacement programs."

Interrogatory:

a) Does "expected service life" as used in the above statement mean that 28% of the transformer population is above a nominal average expected service life developed for actuarial purposes?
   i. If yes, please provide the probability distribution associated with this service life expectation, and identify the maximum age by which 90% of the assets in this class can be expected to have failed.
   ii. If not, please explain in detail what "expected service life" means in this statement.

b) Is there a high probability that the 28% of the transformer population identified as being beyond the "expected service life" will fail in the near future? If yes, please quantify the probability of failure over the next 5 years for each asset and show the calculations used to evaluate those probabilities.

c) Are the expected service life values used to evaluate the assets shown in Figure 2 derived from standard industry values (if so, please provide reference) or Hydro One empirical results (if so, please provide the methodology and calculations)?

d) A large percentage of Hydro One's transformer assets are classified as exceeding "expected service life". Are these assets still providing adequate service in most cases?
   i. If yes, how is "expected service life" useful in determining the timing of these sustaining capital investments?
   ii. If no, what has changed since Hydro One's previous application to prompt the decision to invest now, versus the decision not to invest previously? Please show the associated cost-benefit analysis.

e) Please provide details of the long-term project planning and prioritization process Hydro One intends to use to smooth the demographic bulges shown in Figure 2 to maintain the annual rate impacts of future sustaining capital investments at manageable and predictable levels.

f) Given the number of transformer assets shown as being "Beyond ESL" in Figure 2, please explain how Hydro One's proposed planning approach will avoid putting the system or customers at risk.

Response:

a) No "expected service life" as used in the above statement is not defined as a nominal average expected service life developed for actuarial purposes. Please refer to Exhibit I, Tab 1, Schedule 17, Part c) for the “expected service life” definition.

b) The probability of failure based on Hydro One’s pool of assets is set out below.

Age> ESL	Number of Units	Probability of Failure (%)	# of units expected to fail
Autotransformers	36	9%	3
HV Stepdown	164	21%	34
LV Stepdown	0	0%	0
Regulators	1	54%	0
Reactors	2	40%	1
Total	203	19%	38

Age< ESL	Number of Units	Probability of Failure (%)	# of units expected to fail
Autotransformers	95	6%	6
HV Stepdown	422	8%	34
LV Stepdown	0	0%	0
Regulators	1	0%	0
Reactors	0	0%	0
Total	518	8%	40

This figure was calculated using the conditional probability of failure of each asset surviving the next 5 years given how old it currently is based on the curves defined in Exhibit I, Tab 1, Schedule 20, Part b):

$$P(future\_age \mid current\_age) = 1 - e^{\left[\left(\frac{current\_age}{\eta}\right)^{\beta} - \left(\frac{future\_age}{\eta}\right)^{\beta}\right]}$$

Each of these individual probabilities are then added together to arrive at the expected number of units out of the population that will fail within 5 years.

As per the tables, the transformers beyond the expected service life have a probability of failure of 19%. The probability of failure of the remaining fleet of transformers is 8%. Therefore there is a high probability that these units will fail in the next 5 years.

c) The methodology is consistent with survival analysis in the industry however the empirical results are derived based on Hydro One's data. See Staff 17c.

d) Yes.
   i) Expected service life and asset demographic are two amongst other factors considered in developing sustaining capital investment plans. Please refer to Exhibit B1, Tab 2, Schedule 5.

e) Hydro One has provided a 5 year forecast with this application. The capital spending applied for in the test years and in the remaining 3 years of the transmission system plan reflected in this application is based on asset needs. By ensuring this work is completed in a timely manner, Hydro One will be in a position to deal with the demographic bulges, as the assets deteriorate and lead to additional sustainment requirements in future years.

f) Hydro One uses the concept of reliability risk in its asset management process to gauge the impact of its investments on future transmission system reliability and is complemented by an asset risk assessment process that avoids putting the system and customers at risk. Exhibit B1, Tab 2, Schedule 4, Attachment 1 and Exhibit B1, Tab 2, Schedule 5 describe the respective methodologies and processes in more detail.

Ontario Energy Board (Board Staff) INTERROGATORY #033

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.1.3: Transformers - Asset Assessment Details, Condition, Figure 5 – Transformer Fleet Condition Assessment, pg. 7

"Based on the latest analysis, 15% of Hydro One's transformer population is rated high or very high risk, as outlined in Figure 5."

Interrogatory:

a) Does Hydro One quantitatively calculate the probability of failure for individual transformers, or is the probability of asset failure based upon a qualitative assessment by experienced personnel?
   i. If calculated quantitatively, please provide the calculation methodology utilized and the quantitative calculation results of risk (Probability x Consequence = Risk) for the 49 transformers planned for replacement in 2017 and 2018.

b) Figure 5 shows that very high-risk transformers comprise 2% or about 14 out of the fleet of 721 transformers. Does the designation Very High Risk in this figure indicate an actual Risk (i.e.: Probability x Consequence = Risk) or simply the probability of an imminent failure?
   i. If actual Risk, please quantify both the probability of failure and the consequence of failure for the Very High Risk assets identified in Figure 5.

c) Please quantify the probability of failure range and the timeframe of assessment for each category shown in Figure 5 (e.g.: Category A implies an X% probability of asset failure over the next Y years.)

d) Please explain in detail how Hydro One prioritizes and ultimately selects the high and very high risk assets to be replaced.

Response:

a) No, Hydro One does not quantitatively calculate the probability of failure for individual transformers. The relative risk levels provided in Exhibit B1, Tab 2, Schedule 6 are assigned by experienced personnel who considers quantitative assessments consisting of diagnostic testing results and corrective history, as well as engineering analysis and other relevant qualitative factors.

b) Figure 5 in Exhibit B1, Tab 2, Schedule 6, page 7 is a transformer condition screening at the fleet level. Refer to Exhibit I, Tab 1, Schedule 31, Part c). The Very High Risk categories is a relative risk level based on process described in (a)

c) The time frame for action based on transformer condition assessment at the fleet level is given in the table below:

Category	**Time Frame for Action (where applicable)**
Very High Risk	At earliest opportunity
High Risk	1 to 5 years
Fair	5 to 10 years
Good	10 to 20 years
Very good	>20 years

d) Details pertaining to how Hydro One prioritizes and ultimately selects candidates for replacements using the Asset Risk Assessment process is outlined in Exhibit B1, Tab 2, Schedule 5 and business planning process in Exhibit B1, Tab 2, Schedule 7.

Ontario Energy Board (Board Staff) INTERROGATORY #034

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.1.3: Transformers - Asset Assessment Details, Other Influencing Factors, p. 8

"Safety - Power transformers can experience catastrophic explosions and fire if their condition is deteriorated. Power transformer outages can represent a concern for employee and public safety as individuals may be exposed to unneeded risks and harmed from the results of transformer failure as well as through prolonged power outages."

Interrogatory:

a) Please provide the total number of Hydro One transformers that have failed catastrophically over the past 10 years, by voltage class.

b) Please provide the number of transformers in Hydro One's fleet that are materially susceptible to imminent catastrophic failure, and quantify the probability of catastrophic failure and the period of evaluation for each transformer identified in this response.

c) To which transformers does Hydro One apply real-time gas alarm monitoring to reduce the risk of catastrophic transformer

Response:

a) Please see the table below:

Transformers Failed Catastrophically Over the Past 10 Years 2006-2015

Voltage Class	Number of *Class 1 Failure Transformers
500kV	6
230kV	13
115kV	15

*Class 1 failure is irreparable transformer failure requiring replacement.

b) Hydro One does not knowingly operate transformers that are confirmed to be materially susceptible to imminent catastrophic failure. However, unpredictable transformer failures do occur and based on historical unpredictable failure rates, Hydro One anticipates 4 units per year will be class 1 failures.

c) Hydro One applies real-time gas alarm monitoring on all transformers.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #035

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.1: Circuit Breakers - Asset Overview, p.11

"Currently 9% of the circuit breaker population is beyond its expected service life."

Interrogatory:

a) Is there a high probability that the 9% of the circuit breaker population beyond its "expected service life" will fail in the near future?
   i. If yes, please quantify the probability of failure by asset and show the basis of calculation.
   ii. If yes, please quantify the consequence of failure by asset and show the basis of calculation.

b) Are these assets still providing adequate service in most cases?
   i. If yes, please explain how Hydro One uses "expected service life" in selecting Circuit Breaker sustaining capital investments.
   ii. If no, please explain what has changed since Hydro One's previous filing to prompt the decision to invest now versus the decision not to invest previously, and provide the associated cost-benefit analysis.

Response:

a) Yes, there is a higher probability of failure that the 9% will fail in the near future.

   i. Over the next 5 years it is expected that 41% of the 9% of breakers beyond ESL would fail.

   This figure was calculated using the conditional probability of failure of each asset surviving the next 5 years given how old it currently is based on the curves defined in Exhibit I-01-20b:

$$P(future\_age \mid current\_age\,) = 1 - e^{\left[\left(\frac{current\_age}{\eta}\right)^{\beta} - \left(\frac{future\_age}{\eta}\right)^{\beta}\right]}$$

   Each of these individual probabilities are then added together to arrive at the expected number of units out of the population that will fail within 5 years.

ii. The focus is to replace the ABCB which are installed at Hydro One's bulk power stations with high criticality ratings and a high impact on grid reliability. In some cases, breakers failure will result in customer outages.

b) Yes. Expected service life and asset demographic are two amongst other factors considered in developing sustaining capital investment plans. Please refer to Exhibit B1, Tab 2, Schedule 5.

Ontario Energy Board (Board Staff) INTERROGATORY #036

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.1: Circuit Breakers - Asset Assessment Details, Demographics, pg. 12

"Hydro One uses an expected service life ("ESL") of 40 years for all circuit breakers with the exception of oil circuit breakers, where an ESL of 55 years is used."

Interrogatory:

Are these ESLs based upon industry standard values or an empirical evaluation of the historical performance of Hydro One assets?

i. If the former, please provide a reference.
ii. If the latter, please provide quantified calculations of these ESLs.

Response:

The methodology is consistent with survival analysis in the industry, however the empirical results are derived based on Hydro One's data. See Exhibit I, Tab 1, Schedule 17, Part c).

Ontario Energy Board (Board Staff) INTERROGATORY #037

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Performance, Figure 8 – Forced Outages Frequency of Circuit Breakers, pp. 14-15

"Hydro One uses an expected service life ("ESL") of 40 years for all circuit breakers with the exception of oil circuit breakers, where an ESL of 55 years is used."

Interrogatory:

a) Please define "forced outages" as used above, and categorize the different types of circuit breaker failure modes by frequency of occurrence.

b) What are the failure rates for system circuit breakers versus customer supply circuit breakers?

c) What is the root cause of the step increase in forced outage frequency starting in 2013? Is the root cause linked to changes in Hydro One operational or maintenance practices? Please explain.

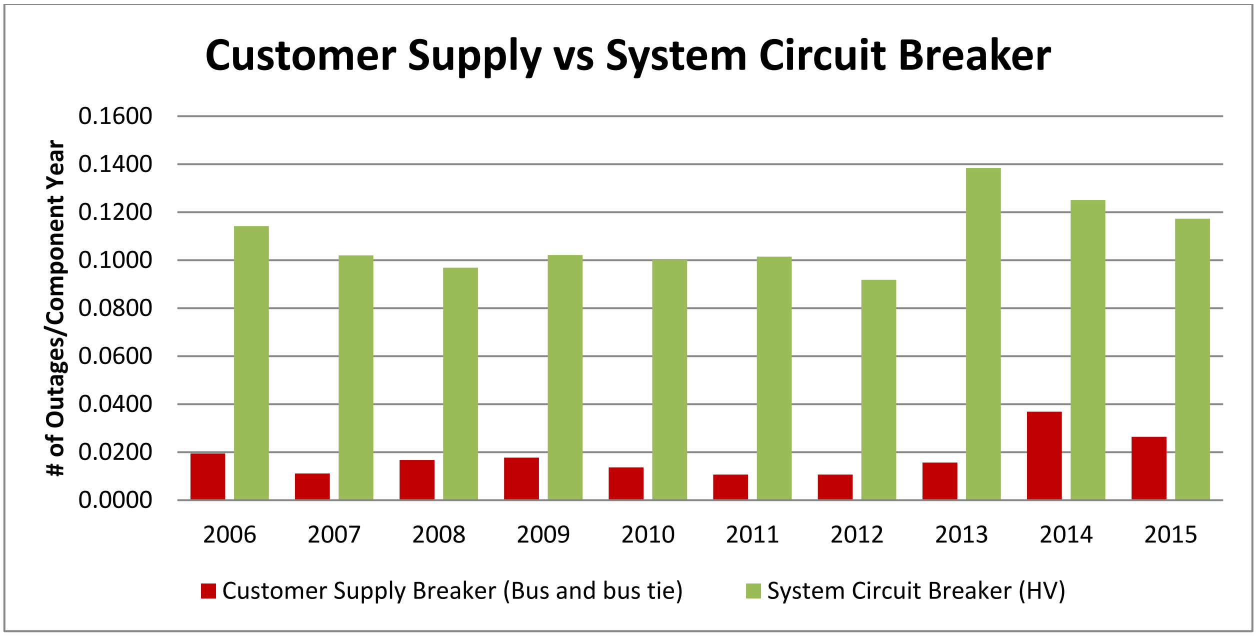
Response:

a) Forced outage as used in the Figures 8 and 9 represents the automatic or forced manual removal of high voltage breakers caused directly by the breaker itself or terminal equipment directly adjacent to the breaker.

Major breaker failure modes ranked by frequency over last 10 years:

Insulation System
Operating Mechanism
Interrupting Medium
Auxiliary Equipment
No Defect/Problem Found
Other Subcomponent
Interrupter
Bushing
Gradient Devices

b)



System breakers, as defined in the graph above, include all high voltage system breakers (>=115kV). Customer supply breakers, as defined above, include all medium voltage bus breakers and bus tie breakers at the delivery point interface.

c) The root cause leading to the step increase in forced outage frequency is an increase in air system control component failures on air blast circuit breakers. There were no reductions in operational practices or maintenance practices. More details on these problems can be found in Exhibit I, Tab 1, Schedule 38, Part d).

Ontario Energy Board (Board Staff) INTERROGATORY #038

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Performance, Figure 10 – Forced Outage Frequency of Circuit Breaker by Type, pg. 15

"In 2014 and 2015 the number of outages has been declining modestly from 2013 as ABCBs have been replaced throughout the system. This trend is notable in Figure 10, where the performance data for the different breakers in Hydro One system is depicted. Oil and SF6 breakers have steady trend whereas ABCBs have a significant increase."

Interrogatory:

a) Please quantify the annual circuit breaker failure rate for each type of circuit breaker, identified in Figure 10, by voltage class.

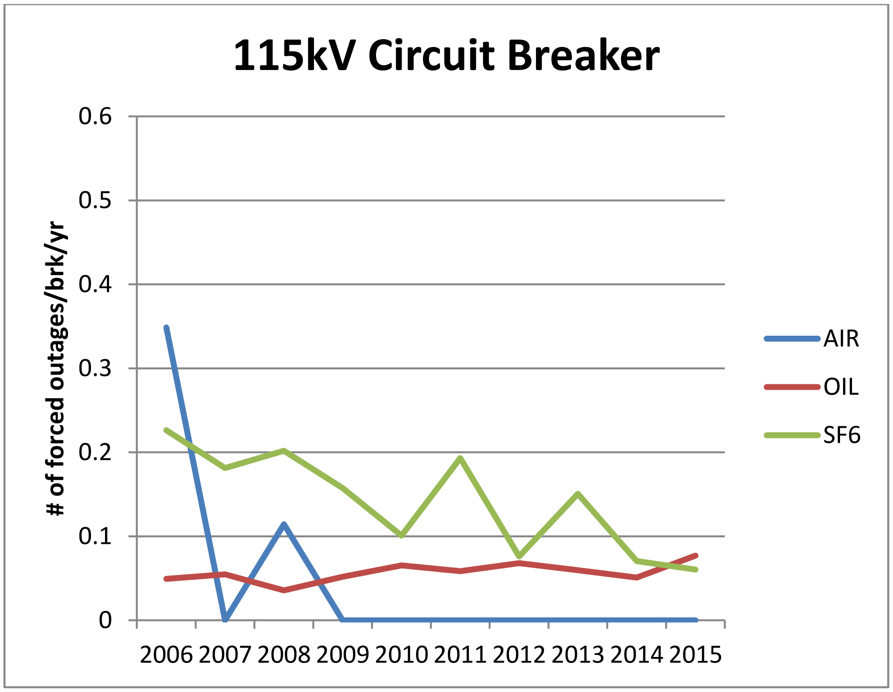
b) What are the primary causes of circuit breaker failures for each type and voltage class?

c) In Figure 10, what caused the 50% increase in oil breaker failures in 2015 versus 2014?

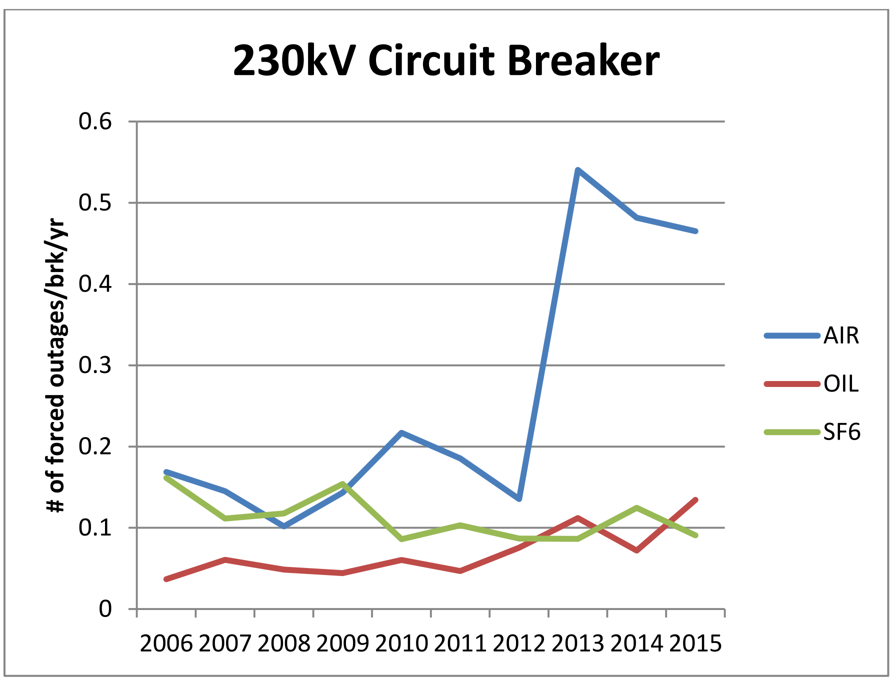
d) What caused ABCB outages to triple in frequency from 2012 to 2013 and to continue performing poorly in 2014 and 2015? Please explain in detail.

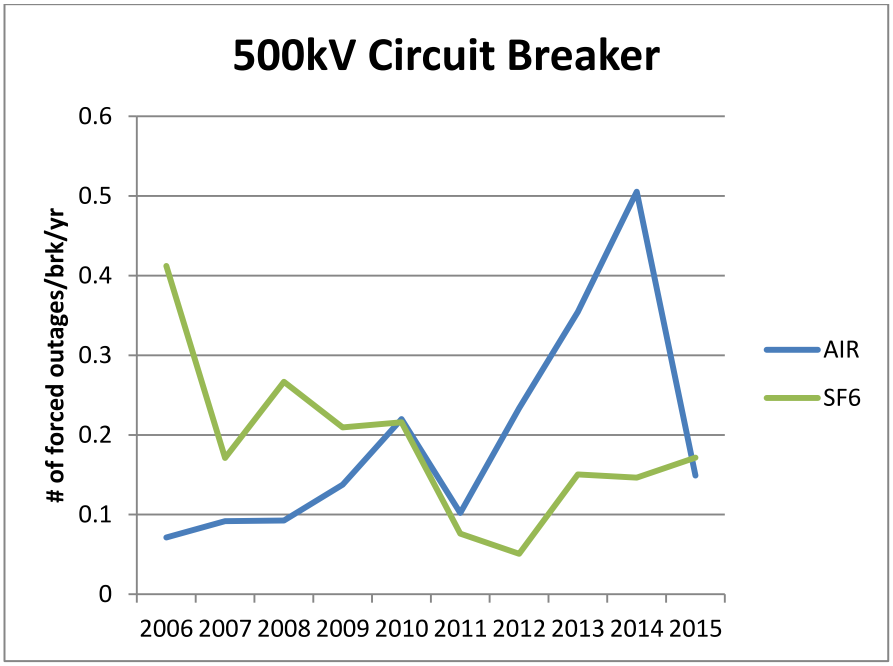
Response:

a) The forced outage rate for each type of circuit break, by voltage class is provided in the graphs below.



*Only 2 115kV ABCB





*No 500kV oil breakers

b)

Voltage	Interrupting Medium	Primary Causes
115	Air	Moisture content
115	Oil	Pneumatic mechanism, latching issues
115	SF6	Gas leak, mechanism issues
230	Air	Control components, air leaks
230	Oil	Pneumatic mechanism, bushings
230	SF6	Gas leak, hydraulic mechanism
500	Air	Air leak, moisture content
500	SF6	Gas leak, hydraulic mechanism

c) The 50% increase in forced outages on oil breakers between 2014 and 2015 was primarily driven by an increase in pneumatic mechanisms and need to force the breakers out of service to address the problem and ensure proper operation of the breaker in future.

d) Much of the increase in air blast circuit breaker forced outages is due to failure of air system control components. The CGE AT population of breakers has caused the greatest number of issues relating to this problem. There have been issues with fill circuits which caused the breakers to continually over pressurize, eventually leading to low air conditions on the breaker. Hydro One has also experienced problems with pneumatically controlled pallet actuators which caused status problems with the breakers, such that operators and protections may see inconsistent status between the pallet and the breaker head. Hydro One has been performing hardening work on the breakers to reduce the frequency of these root causes.

Ontario Energy Board (Board Staff) INTERROGATORY #039

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Asset Assessment Details, pg. 16

"Circuit breaker condition is primarily based on assessment from preventive maintenance and corrective maintenance programs through diagnostic testing such as breaker timing, breaker oil analysis, history of deficiencies, and other tests. The components generally degrade over time based on the amount of usage. In some cases the degradation can be addressed through replacement of worn components during maintenance, but in many cases replacement of the circuit breaker is the only viable solution."

Interrogatory:

a) Please define "history of deficiencies" as used in the above paragraph.

b) Please provide quantified results showing the history of deficiencies of critical system circuit breakers.

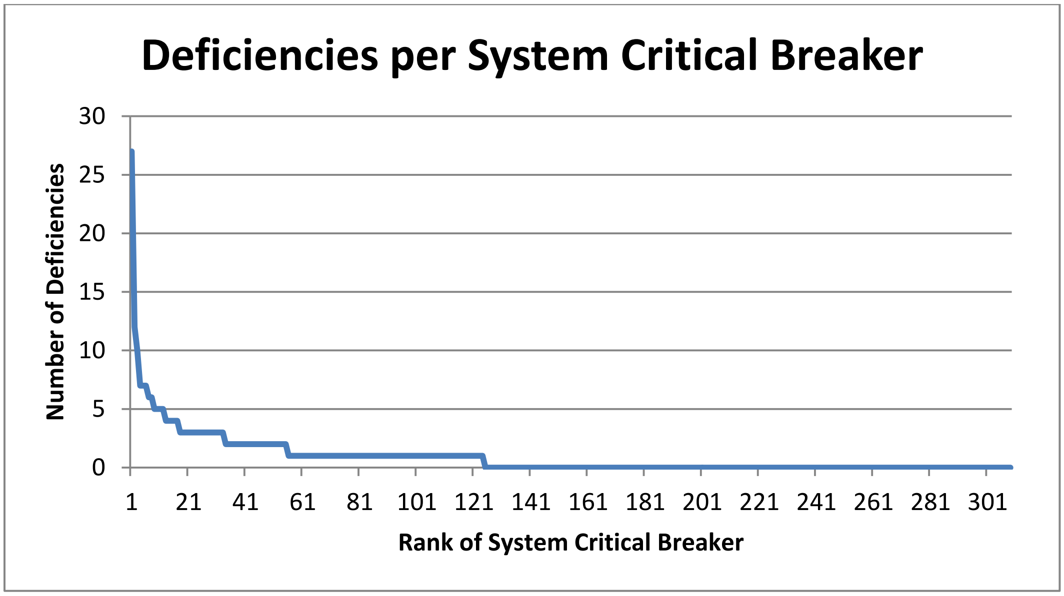
c) It is stated above that "in many cases replacement of the circuit breaker is the only viable solution". Is viability in this statement based upon the economic trade-off of maintenance versus replacement? If not, please explain.

d) Has Hydro One conducted individual asset or overall fleet business case evaluations in developing its circuit breaker replacement plans? If yes, please provide the business case evaluations.

Response:

a) "History of deficiencies" refers to corrective work that has been performed, outcomes of dispatch events to respond to alarming on breakers and also any outstanding minor corrective items that can wait to be addressed until the next maintenance interval.

b) Noted deficiencies by critical system breaker in the last year:



c) This is typically due to economic trade-off between maintenance versus replacement, but can also be influenced by obsolescence, safety, and utilization issues.

d) There are no business cases at individual asset or fleet level, as Hydro One follows an established approval process to justify breaker replacement investments based on a station basis as detailed in Exhibit B1, Tab 2, Schedule 5.

Ontario Energy Board (Board Staff) INTERROGATORY #040

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Figure 11 – Circuit Breaker Fleet Condition Assessment, pg. 16

"Currently 11% of Hydro One's circuit breakers rated high or very high risk based on asset condition, as outlined in Figure 11."

Interrogatory:

a) Does the designation high or very high condition risk indicate an actual Risk (i.e.: Probability x Consequence = Risk) or simply the probability of an imminent failure? If actual Risk, please quantify both the probability of failure and the consequence of failure for the 11% of circuit breakers at high or very high risk.

b) How many of Hydro One's ABCBs are rated as high or very high risk?

c) Please provide details of effective mitigation techniques that Hydro One has implemented to extend the service life of its circuit breaker fleet.

d) How does Hydro One evaluate life cycle costs when deciding between breaker refurbishment and replacement?

Response:

a) No, the designation of very high condition risk is not based on Probability x Consequence. The risk rating of individual assets is based on probability of failure determined through qualitative and quantitative assessment. Quantitative assessment considers the results of diagnostic testing as well as the corrective history of the breaker which indicate a higher probability of failure. Qualitative assessment is based on engineering analysis and judgment to assign a relative risk level by experienced personnel.

b) 10 ABCBs are rated as high or very high risk based solely on an asset analytics condition score. However, based on performance, criticality, obsolescence, economics and other factors, the entire fleet is deemed high/very high risk.

c) Hydro One currently does not have programs to extend breaker service life. We do maintain service life through our maintenance programs. For example:

Preventive maintenance programs are used to perform cyclical maintenance such as diagnostic testing and the replacement of common wear components such as o-rings and contacts.

A hydraulic mechanism overhaul program is in place, where mechanisms are overhauled with the assistance of the manufacturer in order to address one of the main root causes for problems with high voltage breakers.

Where breakers are close to being retired, bridging activities are utilized to address failure modes impacting reliability until the planned replacement date. For ABCB breakers, this has meant implementing control system modifications to remedy identified problems.

d) To evaluate lifecycle costs between refurbishment and replacement options Hydro One utilizes a forecast of expected cost of future maintenance which is informed by our historic costs. These costs along with the cost of replacement and presumed remaining life in the asset are then utilized to perform an NPV comparison between the two scenarios. Different scenarios are run assuming changes to input assumptions in order to perform sensitivity analysis.

Ontario Energy Board (Board Staff) INTERROGATORY #041

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Other Influencing Factors, pg. 17

"Equipment Operations - Breakers that have exceeded their expected service life in terms of number of operations, have parts that are significantly worn, and are considered for replacement. Due to their frequent operation, this is most typical of capacitor and reactor breaker positions."

Interrogatory:

a) Please quantify the annual failure rates for capacitor and reactor breakers.

b) Is the system performance consequence of capacitor and reactor breaker failures typically very significant?

c) In what cases does Hydro One implement Point on Wave operation as standardized practice for capacitor and reactor breaker switching?

Response:

a) Over the last decade the average annual failure rate of reactor breakers and capacitor breakers is as follows:

Function	**Failures / breaker / year**
Capacitor Breaker	0.005
Reactor Breaker	0.012

Failure here is defined as a failure of an interrupter necessitating repair or replacement

b) Reactive power support is a critical element of transmission grid reliability. For system performance the loss of a single capacitor or reactor will generally have minimal impact due to redundancy in the high voltage transmission system. On the medium voltage system there may be an impact on voltage with the loss of the breaker.

c) Hydro One utilizes Point on Wave operation as a standard practice on most high voltage capacitor breaker positions (>=115kV).

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #042

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Other Influencing Factors, pg. 17

"Environmental Impact – Minimizing SF6 emissions and their resultant impact as a greenhouse gas to the environment is considered in the replacement or refurbishment plans for SF6 breakers."

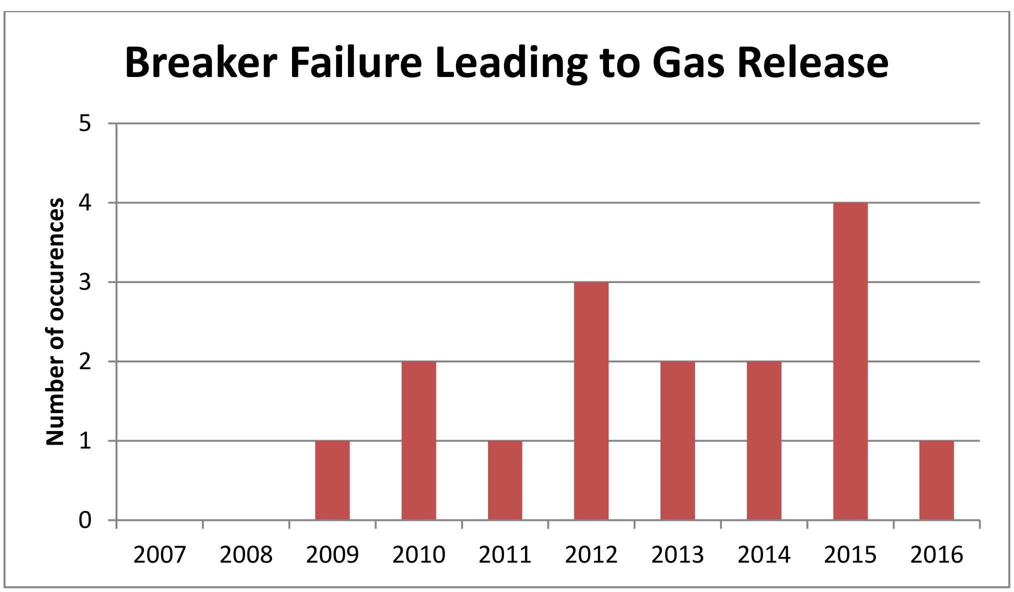
Interrogatory:

a) Please quantify the number of occurrences of Hydro One SF6 circuit breaker failures leading to gas release for the last 10 years, by year.

b) Please describe how Hydro One considers greenhouse gas impacts in its replacement and refurbishment plans for SF6 breakers?

Response:

a)



b) Hydro One's documented strategy for reducing SF6 emissions calls for the following with regard to replacement and refurbishment of SF6 breakers:

- Timely repairs of leaks as specified in our Leak Strategy and Fill Procedures for SF6 Switchgear;

- Replacing poor performing, obsolete and/or prototype SF6 filled equip with: (i) “SF6 free” equipment; (ii) low volume/gas tight SF6 filled equipment; or (iii) hermetically/factory sealed SF6 filled equipment, whenever possible; and

- Specifying: (i) “SF6 free” equipment; (ii) low volume/gas tight SF6 filled equipment; or (iii) hermetically/factory sealed SF6 filled equipment, for new projects whenever possible.

Ontario Energy Board (Board Staff) INTERROGATORY #043

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Other Influencing Factors, pg. 17

"System Evolution – Load growth and renewable generation connections may lead to increase in short-circuit requirement that is beyond the functional capability of existing breakers."

Interrogatory:

How does Hydro One ensure timely replacement of circuit breakers prior to their short circuit interruption capabilities being exceeded? Please describe in detail.

Response:

To assess the changes in short circuit levels due to system upgrades and new or modified customers' connection facilities, Hydro One performs project-specific short circuit studies to evaluate the increase in short circuit levels and identifies any required breaker upgrades as part of the IESO Connection Assessment and Approval ("CAA") process.

Short circuit changes can occur over time on the existing power system due to the connection of small distributed generation (i.e. less than 500kW) including behind the meter generation and changes in customer facilities, generation characteristics, system topology and the electrical characteristics of neighbouring transmission systems. These changes are not identified by the CAA process. Hydro One conducts system-wide short circuit surveys and reviews short circuit adequacy for all of its breakers annually. The outcome of these reviews informs the selection and specifications of breakers to be replaced.

Ontario Energy Board (Board Staff) INTERROGATORY #044

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.2.3: Circuit Breakers - Asset Assessment Details, Table 5 – Circuit Breaker Replacement Rate, pg. 17

Table 5: Circuit Breaker Replacement Rate

Circuit Breaker Portfolio	Historic			Bridge	Test	
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
# of Replacements	57	83	31	43	66	132
% of Fleet	1.2%	1.8%	0.7%	0.9%	1.5%	2.9%

Interrogatory:

a) What is Hydro One's rationale for doubling the circuit breaker replacement rate from 2017 to 2018?
   i. Does Hydro One currently have the capacity to implement this increased rate of replacement?
   ii. Does Hydro One anticipate that the planned 2018 rate of breaker replacement will carry over into the next cost of service or IRM period that will begin in future Test Year 2019?

b) Given an average expected life of between 40 and 60 years (implied 2.5% to 1.7% average replacement rate), the projected replacement of 3% of circuit breakers in 2018 represents a significantly accelerated rate of replacement. If continued going forward, a 3% annual replacement would be anticipated for assets with an average expected life of 33 years. What are the forecast annual rates of breaker replacement through the years 2019-2021?

Response:

a) At the approximate 1% per year replacement rate which was done in 2014/2015, it would require 100 years to replace the entire fleet. The doubling is required to address the breakers that are in poor condition and performing poorly.
   i. Yes
   ii. Yes, however, detailed post 2018 plans are yet to be finalized.

b) The forecast annual replacement rate 2019-2021 is 2.8%, however, these details have yet to be finalized and Hydro One is seeking approval in this application only for amounts in 2017 and 2018. This application is not seeking approval for expenses during the 2019-2021 period.

Ontario Energy Board (Board Staff) INTERROGATORY #045

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.3.3: Protection and Automation - Asset Assessment Details, Performance, pg. 25

"The forced outage frequency of equipment caused by protection systems has been declining for lines equipment and a relatively stable trend for station equipment over the past 10 years."

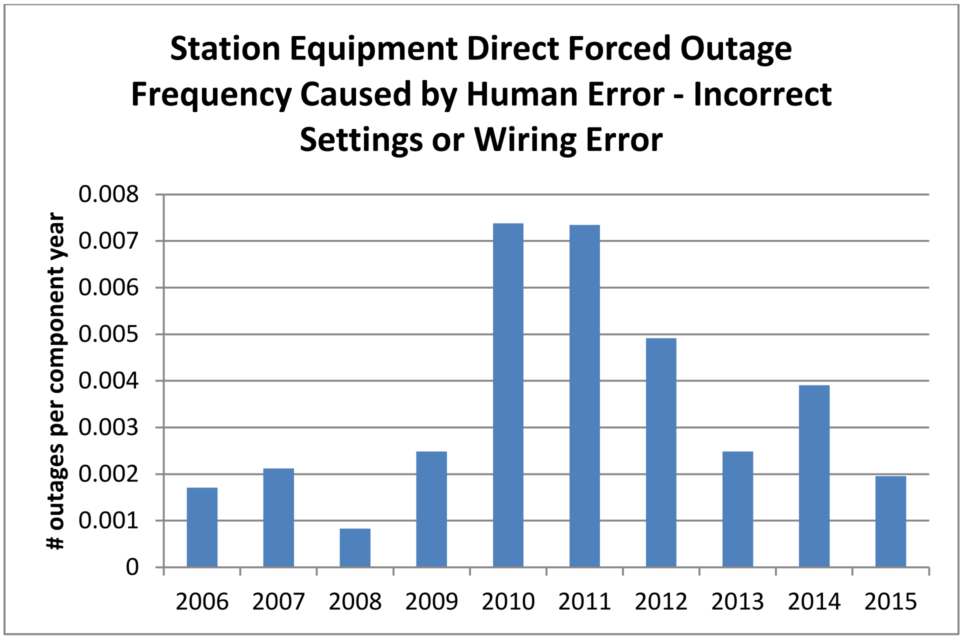
Interrogatory:

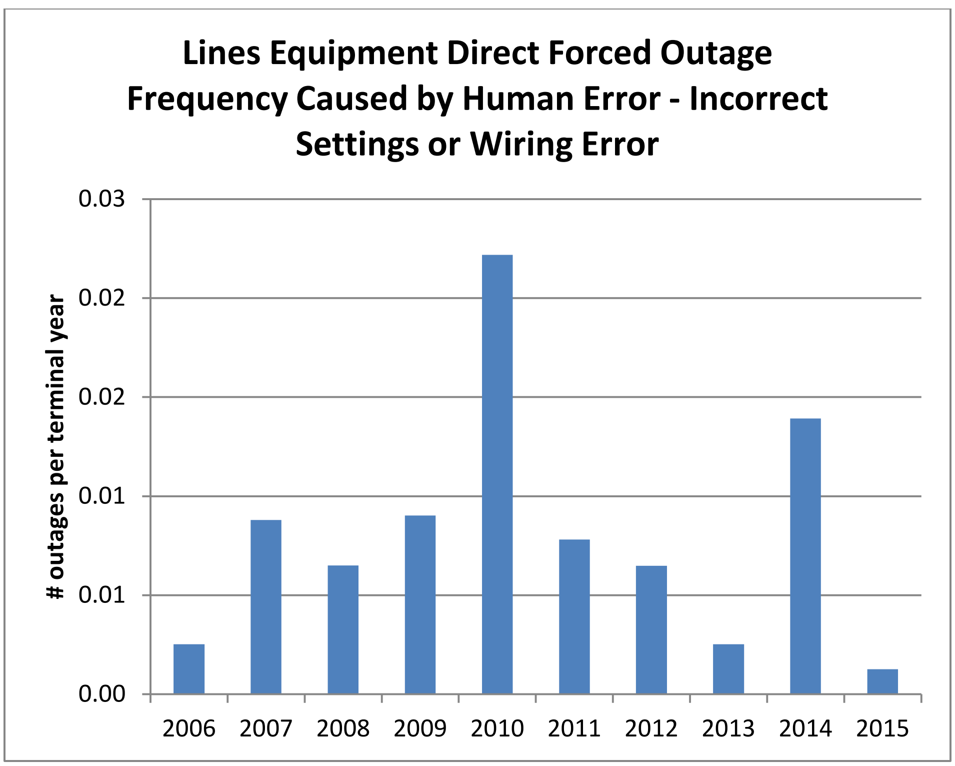
What percentage of Hydro One forced outages due to protection system mis-operation is caused by incorrect protection settings or applications, and what percentage is caused by protection system equipment or hardware failure?

Response:

For 2015, the percentage of forced outages due to protection system incorrect settings is 4.5% for station components and 4.4% for lines. The percentage of forced outages due to protection system equipment or hardware failure is 95.5% for station components and 95.6% for lines.

The forced outage graph presented in Exhibit B1, Tab 2, Schedule 6, Section 2.3.3: Protection and Automation is based on protection system equipment failure. Below is a stations and line forced outage graph due to human error which includes incorrect settings or wiring error.


Station Equipment Direct Forced Outage Frequency Caused by Human Error - Incorrect Settings or Wiring Error
outages per component year
0.008
0.007
0.006
0.005
0.004
0.003
0.002
0.001
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015


Lines Equipment Direct Forced Outage Frequency Caused by Human Error - Incorrect Settings or Wiring Error
outages per terminal year
0.03
0.02
0.02
0.01
0.01
0.00
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

Ontario Energy Board (Board Staff) INTERROGATORY #046

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.3.3: Protection and Automation - Asset Assessment Details, Performance, pg. 26

"Programmable Auxiliary Logic Controller (PALC) relays, one type of solid state protection system, have shown an increase in recorded defects and trouble calls over the years. Hydro One has been actively replacing PALC relays and approximately 200 PALCs have been replaced in 2014 and 2015."

Interrogatory:

Are the PALC relays affected by manufacturer "type faults" or is the increase in defects due to thermal cycling or some other deterioration factor? If other, please specify.

Response:

PALC relays were deployed at Hydro One (Ontario Hydro) since late 1980s and early 1990s. The mean time between failures (MTBF, the universally accepted measure of device reliability) for the PALC relays is around 30-40 years in comparison to current microprocessor IEDs that have a specification of 100 years. The increase in defects is a result of deteriorating components within the relay. Critical components such as the Output Relay card and Analog Input Module card have been identified as the cause of failure. In 2012 Hydro One requested that Kinectrics perform an accelerated life test on PALC relays and the report (PR-90-027 Accelerated Life Test – Programmable Auxiliary Logic Controller (PALC)) recommends that the remaining PALC population should be replaced within 5-10 years, which is by 2022. See Attachment 1 of this response.

Hydro One Networks Inc.

ACCELERATED LIFE TEST – PROGRAMMABLE AUXILIARY LOGIC CONTROLLER (PALC)

Kinectrics Report No.: K-418047-RA-0001-R00
Hydro One Report No.: PR-90-027-R00

Prepared by:

Arend Koert - Kinectrics Inc.

7 May 2012

LIMITATION OF LIABILITY AND DISCLAIMER

This report was prepared as an account of work sponsored or cosponsored by Hydro One Networks Inc. Neither Hydro One Networks Inc. nor any person employed on its behalf, nor any sponsor/cosponsor makes any warranty, or representation whatsoever, expressed or implied, or assumes any legal responsibility for the accuracy, adequacy, or completeness of the information contained in this document, or accepts any liability for the use, or damages, either directly, consequentially, or otherwise, resulting from the use thereof.

CONTACT/PUBLISHER

This document is the responsibility of the Transmission Projectes Development Division, Hydro One Networks Inc. Please contact the Manager with any queries or suggestions.

Strategy
Transmission Projects Development Division
483 Bay Street (TCT15N)
Toronto, Ontario, M5G-2P5
www.HydroOne.com

hydro one

Hydro One Networks Inc.

Accelerated Life Test – Programmable Auxiliary Logic Controller (PALC)

Kinectrics Report No.: K-418047-RA-0001-R00
Hydro One Report No.: PR-90-027-R00

	Prepared by	Reviewed by	Reviewed by
SIGNATURE:		Tom Gough	
NAME:	A. Koert	T. Gough	S. Cress
TITLE:	Principal Engineer Transmission & Distribution Technologies	Senior Engineer NPQ	Manager, Distribution Asset Management Transmission & Distribution Technologies

	Approved by	Approved by	
SIGNATURE:		Paul DiFilippo	
NAME:	D. Clarke	P. DiFilippo	
TITLE:	General Manager Transmission & Distribution Technologies	Reliability Standards Manager - P&C Strategy P&C Strategies & Standards Dept. System Investment Division Hydro One Networks Inc	

Dated: May 7, 2012

PAGE INTENTIONALLY LEFT BLANK

Table of Contents

EXECUTIVE SUMMARY **1**

1 INTRODUCTION **5**

2 SCOPE **5**

3 METHODOLOGY **5**
3.1 Determining Ageing Test Length 5
3.1.1 Critical component with highest activation energy 6
3.1.2 Parts count analysis -- overall PALC AF 7
3.2 Focus on R(5|20) & AF Granularity 8
3.2.1 Pragmatic approach 8
3.2.2 AF granularity 9
3.3 PALC Test Batch 11

4 TEST PREPARATION **13**
4.1 Test Batch Preparation 13
4.2 Test Set-up Preparation 15

5 PRE-AGEING TEST **16**
5.1 In-service Configuration Test 17
5.2 Power Supply Module Test 17
5.3 Test-specific Ladder Diagram Test 18

6 AGEING CYCLES **20**

7 POST-AGEING TESTS **22**
7.1 Post-Ageing Test (Cycle 1) 22
7.1.1 In-service configuration test 22
7.1.2 Power supply modules 23
7.1.3 Test-specific ladder diagram test (Omicron test) 23
7.2 Post-Ageing Test (Cycle 2) 24
7.2.1 In-service configuration test 24
7.2.2 Power supply module test 24
7.2.3 Test-specific ladder diagram test (Omicron test) 25
7.3 Post-Ageing Test (Cycle 3) 25

7.3.1 In-service configuration test 25
7.3.2 Power supply module test 26
7.3.3 Test-specific ladder diagram test (Omicron test) 27

8 ANALYSIS 27
8.1 Assessment of PALCs against Reliability Target 27
8.2 Performance or Degradation Modelling 29
8.2.1 Power supply module measurements 29
8.2.2 Relay / output driver timing and voltage threshold measurements 33
8.2.3 Qualitative observations of PALC performance 42

9 CONCLUSIONS 42

10 RECOMMENDATIONS 43

11 ACKNOWLEDGEMENTS 43

12 REFERENCES 44

13 BIBLIOGRAPHY 44

14 APPENDIX A: TEST PROCEDURE 45

15 APPENDIX B: TEST SET-UP 53

16 APPENDIX C: TEST BATCH LABELLING & VISUAL INSPECTION 66

17 APPENDIX D: TEST-SPECIFIC LADDER DIAGRAM 69

18 APPENDIX E: OMICRON SCREEN-SHOTS 78

19 DISTRIBUTION 84

List of Figures

Figure 4.1 – PAC3 bent faceplate 13
Figure 4.2 – PAC25 (250V): over-heating around resistor pairs 13
Figure 4.3 – PAC6: replacement of defective DPDT switch 14
Figure 4.4 – AIM: replacement of defective push-to-make switch 14
Figure 4.5 – AIM: broken button on push-to-make switch 14
Figure 4.6 – AIM: improperly re-inserted EPROM 14
Figure 4.7 – PAC27: slightly damaged edge-connector 14
Figure 4.8 – PAC4: missing EPROM masks 14
Figure 4.9 – Power Supply Module test set-up showing power supply and CPU slot test jig with loads 15
Figure 4.10 – Omicron CMC 256-6 connections and rear view of PALC crate with wiring harness and I/O Slot 5 test jig (8-pole, 12Vdc relay) 15
Figure 4.11 – I/O slot 5 test jig (PSM monitoring) (1 of 12) 16
Figure 4.12 – PAC4 EPROM cards (one spare) with test-specific ladder 16
Figure 7.1 – Faulty C21 and repaired AIM-04 22
Figure 7.2 – Faulty relay and repaired OR6-04 22
Figure 7.3 – Faulty C20 and repaired AIM-04 24
Figure 7.4 – 3x burnt resistors in PSM-03 26
Figure 8.1 – PSM +5V output performance 30
Figure 8.2 – PSM -5V output performance 31
Figure 8.3 – PSM +12V output performance 32
Figure 8.4 – Pick-up time (PAC25 to PAC6) 34
Figure 8.5 – Drop-off times (PAC25 to PAC6) 35
Figure 8.6 – Pick-up time (PAC25 to PAC27/PAC7) 36
Figure 8.7 – Drop-off time (PAC25 to PAC27/PAC7) 37
Figure 8.8 – Dead-to-low voltage threshold (AIM to PAC27/PAC7) 38
Figure 8.9 – Low-to-dead voltage threshold (AIM to PAC27/PAC7) 39
Figure 8.10 – Low-to-high voltage threshold (AIM to PAC27/PAC7) 40
Figure 8.11 – High-to-low voltage threshold (AIM to PAC27/PAC7) 41

List of Tables

Table 3.1 – Cumulative test time vs. required 12-month test time 8
Table 3.2 – Ageing cycle lengths 10
Table 3.3 – Simulated age vs. component category 10
Table 3.4 – Maximum failure number vs. sample size 11
Table 3.5 – Distribution of components/cards/modules delivered to Kinectrics ..12
Table 3.6 – Homogeneous PALC card mix...12
Table 4.1 – List of test equipment...16
Table 5.1 – PSM test results: Pre-Ageing 17
Table 5.2 – Card set composition for Omicron tests 18
Table 5.3 – Card Set 1 for Input Sequence 1 to 8.seq 19
Table 5.4 – Card Set 1 for Input Sequence 9 to 16.seq 19
Table 5.5 – Card Set 1 for Ramping.rmp 20
Table 6.1 – PALC crate/card set composition...21
Table 6.2 – Ageing cycles...21
Table 7.1 – PSM test results: Post-Ageing (Cycle 1) 23
Table 7.2 – Observations during Omicron test: Post-Ageing Test (Cycle 1).......23
Table 7.3 – PSM test results: Post-Ageing (Cycle 2) 24
Table 7.4 – Observations during Omicron test: Post-Ageing Test (Cycle 2).......25
Table 7.5 – PSM test results: Post-Ageing (Cycle 3) 26
Table 7.6 – Observations during Omicron test: Post-Ageing Test (Cycle 3).......27
Table 8.1 – Summary of relevant failures and simulated age 28
Table 8.2 – Decision matrix for R(X|20) targets 28

EXECUTIVE SUMMARY

Accelerated Life Test – Programmable Auxiliary Logic Controller (PALC)

OVERVIEW

Hydro One has been using Programmable Auxiliary Logic Controllers (PALCs) for around 20 years. As with some of Hydro One's other equipment, PALCs are obsolete and will need to be replaced.

Kinectrics conducted an accelerated life test on a batch of PALCs to help Hydro One with its asset management strategy.

BACKGROUND

As part of an aggressive asset management strategy, Hydro One is replacing old equipment that has reached its theoretical end-of life. However, Hydro One has limited resources (staff) and needs to prioritise the replacement work. So Hydro One needs to know how long it will be before failures start to escalate. For instance, knowing whether the PALC population will last another 5, 10 or 15 years will enable Hydro One to revise or optimise its replacement programs, funding and resources.

OBJECTIVES

Assess the reliability of the PALC population for another 5, 10 and 15 years given that it has already survived 20 years. In reliability (probability) notation, this may be expressed as conditional reliabilities: R(5|20), R(10|20) and R(15|20). The PALC population reliability target was selected as R(X|20) > 70%, 90% confidence (single-tailed), where X = 5, 10 and 15.

APPROACH

Accelerated ageing based on the Arrhenius reaction rate model was employed. The electronic component specifications limit the heat soak temperature to 70 °C which, compared to a typical usage temperature of 24 °C, yields an overall PALC calculated acceleration factor of only 5.02. Consequently, each 5-year period would then require the PALCs to be heat-soaked over 12 months, or 36 months for the complete ageing test.

This duration is impractically long and so led to the acceleration factor granularity concept [1], where component categories are ranked from highest to lowest acceleration factor, and the required heat-soak period is broken up into chunks coinciding with component categories successively reaching 5 simulated years. When the number of failures exceeds the maximum allowed, a reliability target

"not met" decision is reached. Otherwise, as long as (i) the number of failures does not exceed the maximum allowed and (ii) 5 simulated years has not yet been reached, the result is deemed "inconclusive" and heat-soaking must continue until a reliability target "met" decision is reached.

RESULTS

The accelerated life test comprised a pre-ageing test and three ageing cycles of 3 months, 2 months and 1 month, with each ageing cycle followed by a post-ageing test. The pre- and post-ageing tests comprised functionality testing of power supply module and PALC cards using an Omicron relay tester.

As the number of relevant failures exceeded the maximum allowed, the Output Relay card did not meet the reliability target for X = 5, 10 and 15 years, whereas the AIM card did not meet the reliability target for X = 10 and 15 years.

The results for all other cards remain inconclusive because no other failures occurred and 5 simulated years had not yet been reached for all on-board components.

As most deployed PALCs would contain an Output Relay card, it may be stated that the overall PALC does not meet the reliability target for X = 5, 10 and 15 years.

PALC performance degradation was also considered as a means to assessing reliability by analysing power supply module test and Omicron test results from the Pre-Ageing Test, Post-Ageing Test (Cycle 1), Post-Ageing Test (Cycle 2) and Post-Ageing Test (Cycle 3). There was no apparent quantitative degradation. However, qualitative degradation was observed in the form of switches that exhibited bad electrical contact and mechanical stiffness in the 2nd and 3rd post-ageing tests but these do not affect the core functionality of the PALCs, i.e., the switches are used for operator access, as may be required from time-to-time.

CONCLUSIONS

Unless a particular failure mode – in a complex, multi-component product – is being targeted for which an accelerated life test would specifically be designed, then accelerating the age of the product is not a trivial matter because there are limitations in the types of stresses and their levels that may be applied if one is to avoid non-relevant failure modes. An example of such a limitation is the maximum test temperature that may not exceed any component's maximum rating – for the PALC this is 70 °C. An example of a non-relevant failure mode would be one that would never occur during normal use, and the issue of non-relevant failures is especially acute if there is a scarcity of available test items – such as for the PALC.

Consequently, the relatively low allowable test temperature yields a low average acceleration factor requiring a lengthy 12-month test to simulate 5 years. However, different component categories have different acceleration factors allowing an acceleration factor granularity concept to be applied. This allows relatively early reliability assessment decisions to be made despite the fact that individual cards or indeed the entire PALC have not yet been aged by another 5 or more years.

This accelerated life test demonstrated that Hydro One's PALC population will not survive another 5 years of trouble-free operation, and this must be factored into Hydro One's asset management strategy. This statement – and in particular the term "trouble-free" – is further qualified if it is borne in mind that the selected reliability target of $R(X|20) > 70\%$ is not particularly stringent, but one that may be considered appropriate if Hydro One is to repair and/or replace PALCs, as and when failures occur. Whereas the result is clear at PALC level, further testing would be required in view of inconclusive results at individual card level should definitive "met / not met" reliability assessment decisions be required at card level.

RECOMMENDATIONS

Given the relatively non-stringent reliability target of $R(X|20) > 70\%$, PALCs utilising Output Relay cards should be replaced within the next 5 years, whereas PALCs utilising AIM cards should be replaced within the next 10 years.

Additional accelerated ageing cycles would help to eliminate the "inconclusive" results at individual card level for cards other than Output Relay and AIM.

PALCs could be given a longer lease on life through refurbishment of Output Relay cards and AIM cards. Kinectrics could provide this service given in-house knowledge and expertise on PALCs, and new cards could be made if necessary.

It would be useful to compare test results to field-failure statistics; presumably these exist at Hydro One's Meter and Relay Services.

Alternative means to increase acceleration factor – without introducing non-relevant failure modes – need to be explored.

KEYWORDS

Accelerated life test, Programmable Auxiliary Logic Control (PALC), reliability, Arrhenius reaction rate model

PAGE INTENTIONALLY LEFT BLANK

1 INTRODUCTION

Hydro One has an aggressive asset management strategy in place, and is replacing old equipment that has reached its theoretical end-of-life (20 years and older) and for which spares are no longer available, i.e., obsolete. However, Hydro One has limited resources (staff) and needs to prioritise the replacement work.

Although replacement of the Programmable Auxiliary Logic Controller (PALC) population is ongoing as part of its asset management strategy, this equipment represents a substantial portion of the work, and Hydro One needs to know how long it will be before failures start to escalate. For instance, knowing whether the PALC population will last another 5, 10 or 15 years will enable Hydro One to revise or optimise its replacement programs, funding and resources.

Therefore the purpose of this project is to assess the reliability of the PALC population for another 5, 10 and 15 years given that it has already survived 20 years. In reliability (probability) notation, this may be expressed as conditional reliabilities: R(5|20), R(10|20) and R(15|20).

2 SCOPE

The scope of this project comprised the following:

- Develop methodology [1]
- Prepare test batch
- Conduct Pre-Ageing test
- Conduct Ageing Cycles 1 to 3 (with their respective Post-Ageing tests)
- Analyse results and compile test report

3 METHODOLOGY

3.1 Determining Ageing Test Length

An effective method to accelerate time-to-failure (TTF) of a material is to subject it to constant elevated (stress) temperature over a period of time (heat soak) as per the Arrhenius reaction rate model:

$$AF = e^{\frac{E_a}{k}\left(\frac{1}{T_u} - \frac{1}{T_s}\right)} \tag{3.1}$$

where:

AF is acceleration factor
E_a is activation energy
k is Boltzmann's constant (8.617×10^{-5} eV/K)
T_u is normal-use temperature (K)
T_s is stress temperature (K)

3.1.1 Critical component with highest activation energy

Critical components are ones, e.g., microprocessor, whose failure will cause PALC failure, whereas the failure of non-critical components, e.g., LEDs, will not affect core functionality of the PALC.

The original approach was to subject a PALC sample to a destructive tear-down analysis and select the most critical component with the highest activation energy. The resultant AF_{crit} determines the required test length to simulate each 5-year period.

However, this approach was deemed inappropriate because:

- A PALC comprises complex, multi-component cards with many critical components
- Only the critical components with the highest activation energy would experience any appreciable life acceleration; for the rest, $1 \leq AF < AF_{crit}$
- Focusing on the most critical component may be misleading because under service conditions (normal-use temperature), a critical component with high activation energy may outlast a less critical component with lower activation energy, as per the Arrhenius reaction rate equation:

$$TTF = Ae^{\frac{E_a}{kT_u}} \tag{3.2}$$

where:
TTF is time-to-failure
A is a constant that depends on product geometry, specimen size and fabrication, and other factors
E_a is activation energy
k is Boltzmann's constant (8.617×10^{-5} eV/K)
T_u is normal-use temperature (K)

Stated differently, from equation (3.1), larger E_a yields larger AF, which is desirable; from equation (3.2), larger E_a also means larger TTF at normal-use temperature, whereas it would be desirable to accelerate the life of critical components with smallest normal-use *TTF*.

3.1.2 Parts count analysis -- overall PALC AF

A parts count analysis was undertaken to calculate an overall PALC failure rate at normal-use temperature and at elevated (stress) temperature, to yield an overall AF. Briefly, the steps comprise the following:

1) Determine the failure rate per component category (resistors, polycarbonate capacitors, polyester capacitors, ICs, tantalum capacitors etc.) at a given reference temperature as per MIL-HDBK-217F [2].

2) At normal-use temperature:
   a) Calculate AF per component category using the extended Arrhenius reaction rate equation, as per IEC 61709 [3].
   b) Add the failure rates of all components to yield the PALC overall failure rate.

3) At elevated (stress) temperature:
   a) Calculate AF per component category using the extended Arrhenius reaction rate equation, as per IEC 61709.
   b) Add the failure rates of all components to yield the PALC overall failure rate.

4) The ratio of these overall failure rates is the overall PALC AF.

   Notes:
   (i) The extended Arrhenius reaction rate equation provides for up to two activation energies per component category, and is considered sufficient to model the failure rate vs. temperature dependency adequately, even in cases where more than two different failure mechanisms are dominant.

   (ii) Failure rate values account for self-heating of components, in particular for diodes, transistors, ICs and opto-couplers.

   (iii) Failure rates in MIL-HDBK-217 are generally considered to be conservative, but in this application, it is the ratio of the failure rates at elevated vs. normal use temperature that matters.

<u>Result</u>:
In a previous ageing test conducted on IRX relays [4], Hydro One specified the average temperature of relay rooms as 24 °C. PALCs are installed in the same

relay room environment. Therefore, with T_u = 24 °C, and selecting T_s = 70 °C, as this is the absolute maximum temperature rating for most of the ICs, the overall PALC AF is 5.02. Therefore each simulated 5-year period requires 12 months. Moreover, a total of 15 simulated years requires 36 months. This is excessive and would impact on environmental chamber / oven availability.

3.2 Focus on R(5|20) & AF Granularity

With the relatively low overall PALC AF, demonstrating R(5|20), R(10|20) and R(15|20), as per the original scope of work, was too ambitious, i.e., the project needed to focus on R(5|20), but the required 12 months remained excessive.

3.2.1 Pragmatic approach

A more pragmatic approach was required where the test runs until a definitive result is obtained. This required the 12 test months to be broken up into appropriate chunks (or Ageing Cycles), e.g., 1 month each, with a decision point at the end of each cycle:

Decision Point:

IF number of relevant failures > allowed maximum THEN

  R(5|20) ≤ 70% with 90% confidence, i.e., reliability target not met for further 5 years

  GOTO Final Analysis and Test Report

ELSE

  GOTO Next Ageing Cycle

END IF

Note: Number of relevant failures is the cumulative number of failures from start of test.

In the original scope of work, the decision points were placed at the end of each 5-year simulated period, allowing a definitive “reliability met” or “reliability not met” statement; Table 3.1 puts this into perspective, where the 3rd column represents the success/failure criterion as per the original scope of work.

Table 3.1 – Cumulative test time vs. required 12-month test time

NO. OF RELEVANT FAILURES	CUMULATIVE TEST TIME < 5 SIMULATED YEARS	REQUIRED 12-MONTH TEST (5 SIMULATED YEARS)
Zero up to maximum allowed	Inconclusive: - need more test time	R(5|20) reliability target met
Exceeds maximum allowed	R(5|20) reliability target not met	R(5|20) reliability target not met

In summary, whilst the test is inconclusive, more testing time is required until either:

a) No. of relevant failures exceeds maximum allowed, i.e., R(5|20) reliability target not met, or

b) 5 simulated years is achieved, i.e., R(5|20) reliability target met

Note: If the R(5|20) reliability target is not met, then the R(10|20) and R(15|20) reliability targets are also not met.

The length of each ageing cycle is open to practical considerations: if too short, too much time is wasted between ageing cycles in ramping chamber temperature down, testing PALCs for failure and ramping chamber temperature back up; if too long, the overall test may last longer than necessary if sufficient failures occur early within an ageing cycle. The concept of AF granularity allows the selection of appropriate ageing cycle lengths.

3.2.2 AF granularity

The parts count analysis also yields a distribution of AFs per PALC card, i.e., whereas overall PALC AF is 5.02, each component category has its own AF in the range $AF_{min} = 1.05$ to $AF_{max} = 21.28$. The different component categories age at different accelerated rates when subjected to elevated (stress) temperature.

The aluminium electrolytic capacitors ($AF = 21.28$) age fastest when subjected to elevated temperature, requiring 2.8 months to reach 5 simulated years. Other component categories require more time to reach 5 simulated years. For instance, it will take 12 months for 45% of all PALC components to exceed 5 simulated years -- this is to be expected because overall PALC AF of 5.02 is like an “average” -- and by then the aluminium electrolytic capacitors will have reached 20 simulated years.

Nevertheless, 2.8 months for the aluminium electrolytic capacitors may be considered to be the absolute minimum testing time and may be applied to the 1st Ageing Cycle. Similarly, subsequent ageing cycle lengths may be determined from the 2nd highest AF, 3rd highest AF, and so on, as per Table 3.2. Furthermore, in each subsequent ageing cycle, a larger proportion of PALC components is reaching and exceeding 5 simulated years, as shown in Table 3.3.

Table 3.2 – Ageing cycle lengths

<table>
<tr><th>COMPONENT CATEGORY</th><th>AF</th><th>REQUIRED TEST TIME (FOR 5 YEARS)</th><th>AGEING CYCLE</th><th>AGEING CYCLE LENGTH</th><th>TEST LENGTH (CUMULATIVE)</th></tr>
<tr><td>Al. electrolytic capacitor</td><td>21.28</td><td>2.8 mths</td><td rowspan="3">1st</td><td rowspan="3">2.9 mths</td><td rowspan="3">2.9 mths</td></tr>
<tr><td>Polycarbonate capacitor</td><td>21.06</td><td>2.8 mths</td></tr>
<tr><td>LED</td><td>20.40</td><td>2.9 mths</td></tr>
<tr><td>Polyester capacitor</td><td>14.21</td><td>4.2 mths</td><td rowspan="2">2nd</td><td rowspan="2">1.8 mths</td><td rowspan="2">4.7 mths</td></tr>
<tr><td>E2PROM, CMOS PROM</td><td>12.88</td><td>4.7 mths</td></tr>
<tr><td>High gain opto-coupler</td><td>10.17</td><td>5.9 mths</td><td>3rd</td><td>1.2 mths</td><td>5.9 mths</td></tr>
<tr><td>Silver mica capacitor</td><td>7.96</td><td>7.5 mths</td><td>4th</td><td>1.6 mths</td><td>7.5 mths</td></tr>
<tr><td>Various ICs</td><td>6.59</td><td>9.1 mths</td><td rowspan="4">5th</td><td rowspan="4">2.1 mths</td><td rowspan="4">9.6 mths</td></tr>
<tr><td>Tantalum capacitor</td><td>6.53</td><td>9.2 mths</td></tr>
<tr><td>Diode</td><td>6.40</td><td>9.4 mths</td></tr>
<tr><td>Ceramic capacitor</td><td>6.26</td><td>9.6 mths</td></tr>
<tr><td>Etc.</td><td>Etc.</td><td>Etc.</td><td>Etc.</td><td>Etc.</td><td>Etc.</td></tr>
</table>

Table 3.3 – Simulated age vs. component category

<table>
<tr><th rowspan="3">COMPONENT CATEGORY</th><th colspan="6">AGEING CYCLE</th></tr>
<tr><th>1st</th><th>2nd</th><th>3rd</th><th>4th</th><th>5th</th><th>Etc.</th></tr>
<tr><th>2.9 mths</th><th>1.8 mths</th><th>1.2 mths</th><th>1.6 mths</th><th>2.1 mths</th><th>Etc.</th></tr>
<tr><td>Al. electrolytic capacitor</td><td rowspan="3">≤ 5 yrs</td><td rowspan="3" colspan="2">≤ 10.2 yrs</td><td rowspan="3" colspan="2">≤ 16.6 yrs</td><td rowspan="3">> 16.6 yrs</td></tr>
<tr><td>Polycarbonate capacitor</td></tr>
<tr><td>LED</td></tr>
<tr><td>Polyester capacitor</td><td rowspan="2" colspan="2">≤ 5 yrs</td><td rowspan="2" colspan="3">≤ 10.2 yrs</td><td rowspan="2">> 10.2 yrs</td></tr>
<tr><td>E2PROM, CMOS PROM</td></tr>
<tr><td>High gain opto-coupler</td><td colspan="3">≤ 5 yrs</td><td colspan="2">≤ 8.1 yrs</td><td>> 8.1 yrs</td></tr>
<tr><td>Silver mica capacitor</td><td colspan="4">≤ 5 yrs</td><td>≤ 6.4 yrs</td><td>> 6.4 yrs</td></tr>
<tr><td>Various ICs</td><td rowspan="4" colspan="5">≤ 5 yrs</td><td rowspan="4">> 5 yrs</td></tr>
<tr><td>Tantalum capacitor</td></tr>
<tr><td>Diode</td></tr>
<tr><td>Ceramic capacitor</td></tr>
<tr><td>Etc.</td><td colspan="6">Etc.</td></tr>
</table>

With the project focus on R(5|20), the concept of AF granularity allows the possibility for inferences on R(10|20) and even R(15|20), as illustrated in the example below.

Example:
A number of aluminium electrolytic capacitors failed within the 1st Ageing Cycle but did not exceed the maximum allowed. Within the first couple of weeks into the 2nd Ageing Cycle, more fail thus exceeding the maximum allowed. From the overall PALC AF perspective, it would appear that the R(5|20) reliability target has not been met. Yet at the granular level, for this particular component category, the R(5|20) reliability target has been met because the additional failures are in effect counting towards the R(10|20) reliability target, i.e., the R(10|20) and R(15|20) reliability targets have not been met, and hence by extension, the R(10|20) and R(15|20) reliability targets for the overall PALC have not been met.

AF granularity has been considered for the overall PALC, but may also be applied at the card/module level to consider spares holding, for instance. Depending on the component category distribution per card/module, this may require longer testing time.

Appendices A and B contain the test procedure and test set-up documents compiled by Kinectrics.

3.3 PALC Test Batch

In the original scope of work, reliability target vs. maximum failure number vs. sample size is discussed. For a reliability target of R(X|20) > 70%, 90% confidence (single-tailed), the maximum allowable number of failures (over duration X) vs. sample size, is shown in Table 3.4.

Table 3.4 – Maximum failure number vs. sample size

SAMPLE SIZE	MAX. FAILURE NUMBER
7	0
12	1
16	2
20	3

Hydro One diverted 16 PALCs to Kinectrics, albeit with a non-uniform distribution of cards, and with the understanding that some cards could be faulty. Subsequently, Hydro One delivered further AIM and Output Relay cards to supplement the test batch -- the final distribution of cards/modules is shown in Table 3.5. Unfortunately, no further Output Relay cards were available.

Table 3.5 – Distribution of components/cards/modules delivered to Kinectrics

CARD / MODULE	TYPE	SUB-TOTAL	TOTAL	COMMENTS
Crate	-	16	16	2x 250V; 14x 125V
CPU	PAC3-R2	5	16	120pF soldered onto copper side
	PAC3-R4	11		120pF (C26) included in PCB layout; +2 resistors
CPU d/board	PAC4	16	16	
Input	PAC25-R2	2	15	330nF, 63V soldered onto copper side; 250V
	PAC25-R3	13		330nF, 63V (C9) included in PCB layout; 125V
AIM	AIM-R2	12	12	
Output Relay	PAC6-R3	7	7	
Output Driver	PAC7-R2	3	16	1x 125V; 2x 250V
	PAC27-R2	13		ASIC version of PAC7-R2; all 125V
Blank	PAC9	36	36	

Note: Crate contains Power Supply Module; d/board = daughter board

One of the criteria for accelerated life testing is that the sample must be homogeneous. Noting that the main difference between card revisions is voltage level, i.e., 125 V or 250 V, Table 3.6 shows rack and card availability for a (nearly) homogeneous sample. Ignoring the Output Relay cards, the AIM cards determine the maximum sample size, namely 12.

Table 3.6 – Homogeneous PALC card mix

CARD / MODULE	TYPE	AVAILABLE	SAMPLE SIZE	MAX. FAILURE NUMBER	R(5|20)	SINGLE-TAILED CONFIDENCE
Crate	-	14	12	1	> 70%	90%
CPU	PAC3-R4/R2	16				
CPU d/board	PAC4	16				
Input	PAC25-R3	13				
Output driver	PAC27-R2	13				
AIM	AIM-R2	12				
Output Relay	PAC6-R3	7	7	0	> 70%	90%

Note: This also applies to R(10|20) and R(15|20), where relevant failures from previous ageing cycles are included.

Table 3.6 also shows the maximum failure number and associated statistics. Any failure of Output Relay cards during the Pre-Ageing Test would result in a reduction in sample size affecting the single-tailed confidence, e.g., for a sample size of 4 and a maximum failure number of 0, the single-tailed confidence drops to 75%.

4 TEST PREPARATION

4.1 Test Batch Preparation

All delivered PALCs (crates and constituent cards) were labelled as stipulated in the test procedure (Appendix A) and visually inspected. Appendix C contains a full listing of the delivered PALCs and supplementary cards including the results of the visual inspection.

The following is a summarised list of noted deficiencies – with some example photographs – most of which could have had an impact on testing:

- 2x missing plate between CPU and I/O cards
- 1x missing 8 single-seat ASEA socket
- 6x PAC3 front panel bent (Fig. 4.1)
- 3x PAC3 green PCB coating peeling off in places
- 2x PAC25 (250V) heat damage around 3 resistor pairs (Fig. 4.2)
- 2x PAC6 defective DPDT switches – *each switch replaced* (Fig. 4.3)
- 2x AIM defective push-to-make switches – *each switch replaced* (Fig. 4.4)
- 1x AIM push-to-make switch button broken off (Fig. 4.5)
- 1x AIM EPROM removed and re-inserted incorrectly/improperly (Fig. 4.6)
- 1x PAC27 slightly damaged edge connector (Fig. 4.7)
- 1x PAC4 missing EPROM masks (Fig. 4.8)

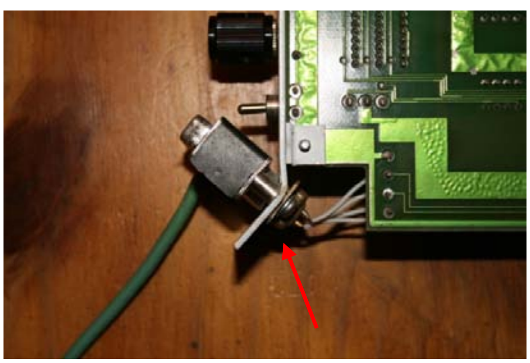


Figure 4.1 – PAC3 bent faceplate

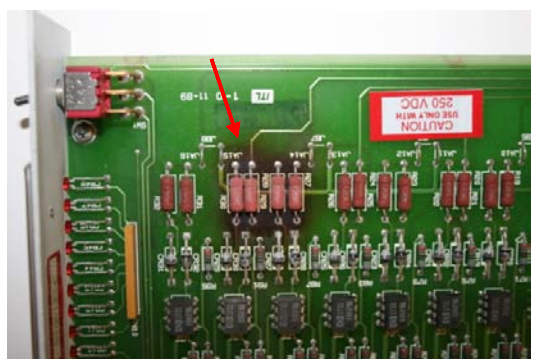


Figure 4.2 – PAC25 (250V): over-heating around resistor pairs

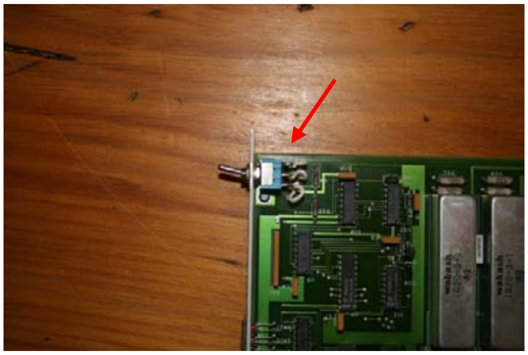


Figure 4.3 – PAC6: replacement of defective DPDT switch

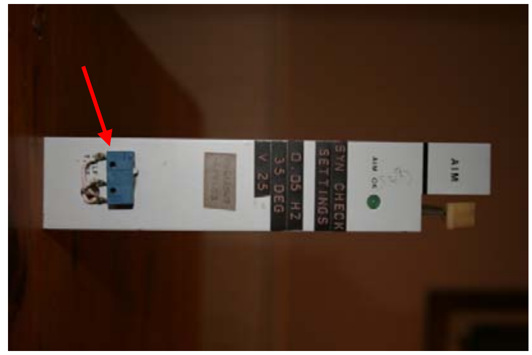


Figure 4.4 – AIM: replacement of defective push-to-make switch

Figure 4.5 – AIM: broken button on push-to-make switch

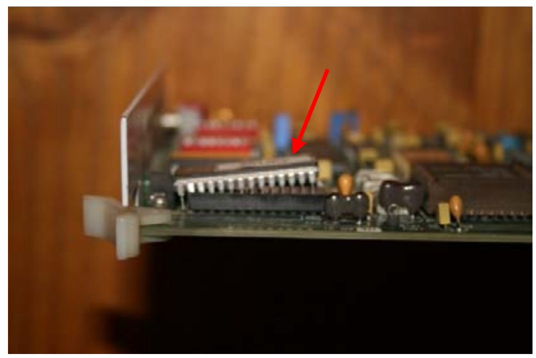


Figure 4.6 – AIM: improperly re-inserted EPROM

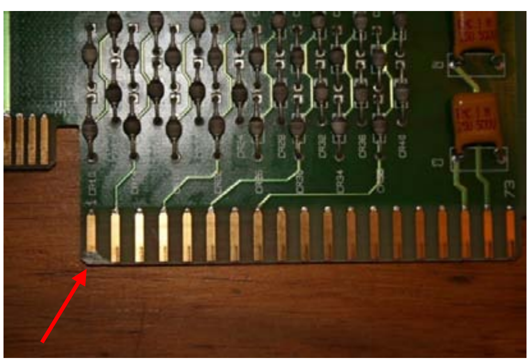


Figure 4.7 – PAC27: slightly damaged edge-connector

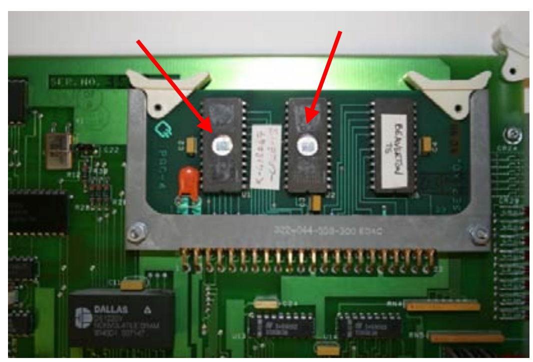


Figure 4.8 – PAC4: missing EPROM masks

All defective switches were replaced to ensure card functionality for the Pre- and Post-Ageing tests. Note that any failure of these replacement switches during the test would be non-relevant, as they are not original components. The push-to-make switch with broken button was not replaced, as a pencil tip (or the like) could be used to depress it. All Input and AIM cards were configured as described in Appendix A.

4.2 Test Set-up Preparation

All test jigs were constructed as per Appendix B; Figures 4.9 to 4.12 show various equipment, test jigs and PAC4 cards. These cards were programmed with a test-specific ladder diagram at Hydro One's Bay Street offices – see Appendix D for a printout of the detailed ladder diagram.

The Omicron relay tester binary output profiles and voltage output profiles were created – see Appendix E for the Omicron screen dumps.

Table 4.1 lists all the equipment used during the Pre-Ageing test, Ageing Cycles and Post-Ageing Cycle tests.

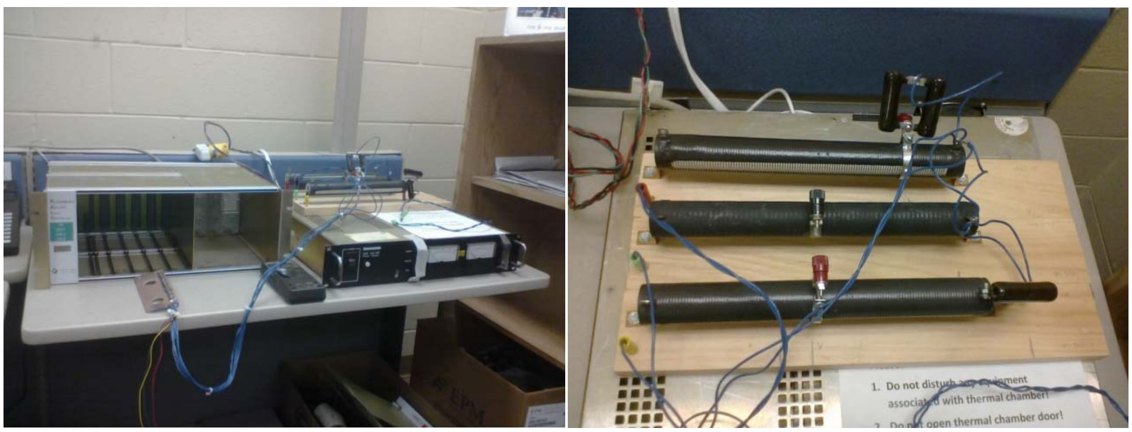


Figure 4.9 – Power Supply Module test set-up showing power supply and CPU slot test jig with loads

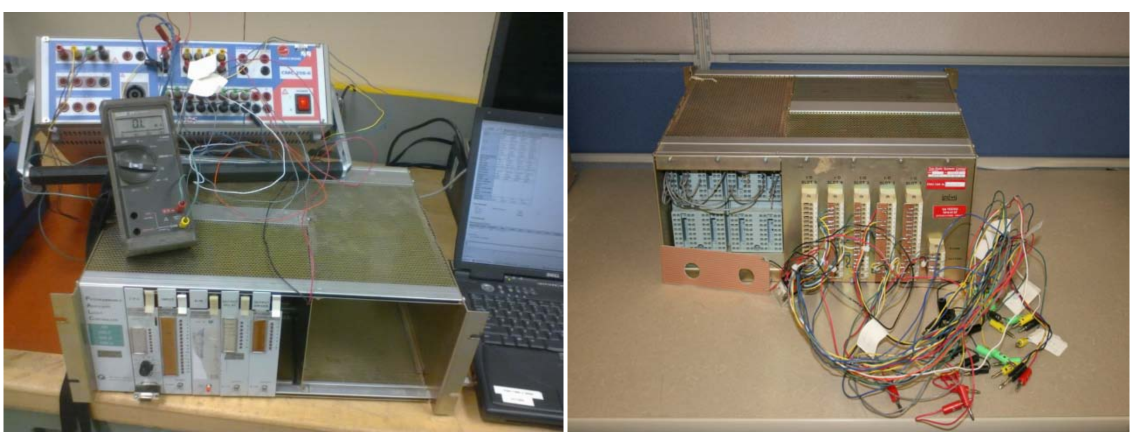


Figure 4.10 – Omicron CMC 256-6 connections and rear view of PALC crate with wiring harness and I/O Slot 5 test jig (8-pole, 12Vdc relay)

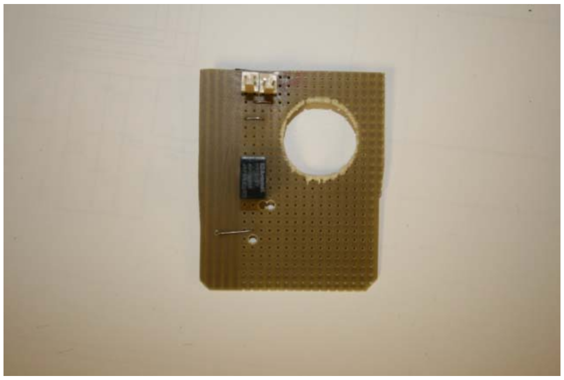


Figure 4.11 – I/O slot 5 test jig (PSM monitoring) (1 of 12)

Figure 4.12 – PAC4 EPROM cards (one spare) with test-specific ladder

Table 4.1 – List of test equipment

#	DESCRIPTION	SERIAL NO.	CALIBRATION	
			DATE	DUE DATE
1	Sorensen DCR 150-6B power supply	9601013	N/A	N/A
2	Tektronix TDS 3034B oscilloscope	B032992	19 Jan 2010	19 Jan 2011
3	OMICRON 256-6	DI547J	14 Jun 2010	14 Jun 2011
4	Fluke 77 multi-meter	2286650	-	-
5	Rotek 3950 AC/DC Precision Calibrator	126	31 Aug 2010	31 Aug 2011
6	Walk-in climatic chamber (KB136)	11407	N/A	N/A
7	Campbell Scientific 21X data logger	11863	4 Feb 2010	4 Mar 2011
8	Campbell Scientific 21X data logger	9654	3 Mar 2011	3 Mar 2012
9	Oven #1 (KB136)	135409	N/A	N/A
10	Oven #6 (forced convection) (KB136)	127755	N/A	N/A
11	Agilent 34901A analog multiplexer	KIN-10419-0	2 May 2011	2 May 2012
12	Agilent 34970A data logger	KIN-00065	13 Jul 2011	13 Jul 2012
13	Tektronix TDS 2024B oscilloscope	KIN-00775	9 Feb 2011	9 Feb 2012
14	Tektronix DPO 2014 oscilloscope	KIN-01568	21 Apr 2011	21 Apr 2012

Notes:
1) Items 1, 6, 9 and 10 are not measuring instruments.
2) Item 3 was calibrated between Pre-Ageing Test and Post-Ageing Test (Cycle 1).
3) Item 4 was verified at 6 Vdc (-0.02 V), 90 mAdc (-0.2 mA), 1 Adc (+0.00 A) and 6 Adc (-0.01 A) using the Rotek 3950 AC/DC Precision Calibrator in the week of 27 Dec 2010.
4) Item 7 was on a 30 day calibration extension.

5 PRE-AGEING TEST

Refer to Appendix A for test procedure detail; this test was performed early January 2011 and comprised:

- In-service configuration test
- Power supply module test
- Test-specific ladder diagram test

Note that any failures found (or that occurred) during the Pre-Ageing Test are classed as non-relevant, as they effectively occurred at or before the commencement of the Ageing Cycles.

5.1 In-service Configuration Test

Appendix C provides a full listing of the 16 PALCs -- crate and constituent cards, as per in-service card configuration -- and supplementary cards that were delivered to Kinectrics. This test ascertains whether these are all in working order, including that the PAC4 (EPROM) recognises the I/O cards as per its native ladder diagram.

One non-relevant failure was found:

- **AIM-12**: Alarm A normally-closed contact (13/14) does not open because relay K1 coil is open circuit. As there were no spare AIM cards, this card was retained for the Ageing Cycles but the relay was not replaced because spare relays were not available; also, Alarm B normally-closed contact (15/16) provides a level of redundancy.

5.2 Power Supply Module Test

Table 5.1 shows the output voltage results for the 125 V and 250 V crates when loaded at rated current.

Table 5.1 – PSM test results: Pre-Ageing

CRATE	+5 V O/P	-5 V O/P	+12 V O/P
125V-PSM-01	4.88	-5.08	11.96
125V-PSM-02	4.88	-5.16	11.86
125V-PSM-03	5.01	-5.13	11.91
125V-PSM-04	5.05	-5.11	11.90
125V-PSM-05	4.86	-5.10	11.94
125V-PSM-06	4.79	-5.05	12.13
125V-PSM-07	5.07	-5.09	11.84
125V-PSM-08	5.11	-5.11	11.79
125V-PSM-09	4.79	-5.11	11.94
125V-PSM-10	4.85	-5.10	11.81
125V-PSM-11	4.77	-5.09	11.88
125V-PSM-12	5.03	-5.14	11.93
125V-PSM-13	4.80	-5.08	12.09
125V-PSM-14	4.89	-5.09	11.93
250V-PSM-01	4.83	-5.16	11.99
250V-PSM-02	-	-	-

All voltage levels were within tolerance with the exception of:

- **250V-PSM-02**: Upon switch-on, the power supply provided voltage output but emitted a high-pitched whine. After switch-off then -on, the power supply no longer provided voltage output.

  This is a non-relevant failure.

5.3 Test-specific Ladder Diagram Test

In the test-specific ladder diagram, inputs map to outputs as follows:

- PAC25 (Inputs 1 to 8) to PAC6 (Output Relays 1 to 8)
- PAC25 (Inputs 9 to 16) to PAC27/PAC7 (Output Drivers 1 to 4)
- AIM OK status to PAC27/PAC7 (Output Driver 5)
- AIM (Inputs 1 to 3) to PAC27/PAC7 (Output Drivers 6 to 8)

As the 16 card sets were not complete, it was necessary to supplement incomplete card sets from Card Set 1 for the Omicron tests. Table 5.2 shows the composition of each card set, where Card Sets 1 to 12 were earmarked for ageing.

Table 5.2 – Card set composition for Omicron tests

CARD SET	CPU	125V-I25	250V-I25	AIM	OR6	125V-OD27	125V-OD7	250V-OD7
1	01	01	-	01	01	01	-	-
2	02	02	-	02	02	02	-	-
3	03	03	-	03	03	03	-	-
4	04	04	-	04	04	04	-	-
5	05	05	-	05	05	05	-	-
6	06	06	-	06	06	06	-	-
7	07	07	-	07	07	07	-	-
8	08	08	-	08	01	08	-	-
9	09	09	-	09	01	09	-	-
10	10	10	-	10	01	10	-	-
11	11	11	-	11	01	11	-	-
12	12	12	-	12	01	12	-	-
13	13	13	-	01	01	13	-	-
14	14	01	-	01	01	-	01	-
15	15	-	01	01	01	-	-	01
16	16	-	02	01	01	-	-	02
TOTALS	16	13	2	12	7	13	1	2

Each card set produced many Omicron relay tester records. As the main purpose of this test was to establish a benchmark of pick-up times, drop-off times, etc. against which deterioration through ageing could be assessed, it suffices to show only those for Card Set 1, as per Tables 5.3 to 5.5. Possible deterioration through ageing is discussed later in this report.

Table 5.3 – Card Set 1 for Input Sequence 1 to 8.seq

Name	**Ignore before**	**Start**	**Stop**	**Tnom**	**Tdev-**	**Tdev+**	**Tact**	**Tdev**	**Assess**
Relay 1 (pick-up)	State 1	State 2	Relay 1 0>1				1.009 s		O
Relay 2 (pick-up)	State 1	State 2	Relay 2 0>1				1.009 s		O
Relay 3 (pick-up)	State 1	State 2	Relay 3 0>1				1.009 s		O
Relay 4 (pick-up)	State 1	State 2	Relay 4 0>1				1.009 s		O
Relay 5 (pick-up)	State 1	State 2	Relay 5 0>1				1.009 s		O
Relay 6 (pick-up)	State 1	State 2	Relay 6 0>1				1.009 s		O
Relay 7 (pick-up)	State 1	State 2	Relay 7 0>1				1.009 s		O
Relay 8 (pick-up)	State 1	State 2	Relay 8 0>1				1.009 s		O
Relay 1 (drop-off)	State 2	State 3	Relay 1 1>0				14.20 ms		O
Relay 2 (drop-off)	State 2	State 3	Relay 2 1>0				14.40 ms		O
Relay 3 (drop-off)	State 2	State 3	Relay 3 1>0				14.10 ms		O
Relay 4 (drop-off)	State 2	State 3	Relay 4 1>0				14.60 ms		O
Relay 5 (drop-off)	State 2	State 3	Relay 5 1>0				14.00 ms		O
Relay 6 (drop-off)	State 2	State 3	Relay 6 1>0				14.30 ms		O
Relay 7 (drop-off)	State 2	State 3	Relay 7 1>0				14.30 ms		O
Relay 8 (drop-off)	State 2	State 3	Relay 8 1>0				14.40 ms		O

Assess: + .. Passed x .. Failed o .. Not assessed

Table 5.4 – Card Set 1 for Input Sequence 9 to 16.seq

Name	**Ignore before**	**Start**	**Stop**	**Tnom**	**Tdev-**	**Tdev+**	**Tact**	**Tdev**	**Assess**
Driver 1 (pick-up)		State 3	Driver 1 0>1				1.008 s		O
Driver 2 (pick-up)		State 3	Driver 2 0>1				1.008 s		O
Driver 3 (pick-up)		State 3	Driver 3 0>1				1.008 s		O
Driver 4 (pick-up)		State 3	Driver 4 0>1				1.008 s		O
Driver 1 (drop-off)		State 4	Driver 1 1>0				7.800 ms		O
Driver 2 (drop-off)		State 4	Driver 2 1>0				7.800 ms		O
Driver 3 (drop-off)		State 4	Driver 3 1>0				7.800 ms		O
Driver 4 (drop-off)		State 4	Driver 4 1>0				7.800 ms		O
Driver 1 (pick-up)	State 7	State 7	Driver 1 0>1				1.009 s		O
Driver 2 (pick-up)	State 7	State 7	Driver 2 0>1				1.009 s		O
Driver 3 (pick-up)	State 7	State 7	Driver 3 0>1				1.009 s		O
Driver 4 (pick-up)	State 7	State 7	Driver 4 0>1				1.009 s		O
Driver 1 (drop-off)	State 8	State 8	Driver 1 1>0				9.000 ms		O
Driver 2 (drop-off)	State 8	State 8	Driver 2 1>0				9.000 ms		O
Driver 3 (drop-off)	State 8	State 8	Driver 3 1>0				9.000 ms		O
Driver 4 (drop-off)	State 8	State 8	Driver 4 1>0				9.000 ms		O

Assess: + .. Passed x .. Failed o .. Not assessed

Table 5.5 – Card Set 1 for Ramping.rmp

Name/ Exec.	Ramp	Condition	Sig	Nom.	Act.	Tol.-	Tol.+	Dev.	Assess	Tact
Line Volts Low (pick-up)	State 1	Driver 8 (Line Volts Low) 0->1	V L1-E		1.503 V				O	700.0 µs
Line Dead (drop-off)	State 1	Driver 6 (Line Dead) 1->0	V L1-E		1.503 V				O	100.0 µs
Line Volts High (pick-up)	State 2	Driver 7 (Line Volts High) 0->1	V L1-E		50.57 V				O	100.0 µs
Line Volts Low (drop-off)	State 2	Driver 8 (Line Volts Low) 1->0	V L1-E		50.57 V				O	500.0 µs
Line Volts Low (pick-up)	State 3	Driver 8 (Line Volts Low) 0->1	V L1-E		50.19 V				O	100.0 µs
Line Volts High (drop-off)	State 3	Driver 7 (Line Volts High) 1->0	V L1-E		50.19 V				O	500.0 µs
Line Dead (pick-up)	State 4	Driver 6 (Line Dead) 0->1	V L1-E		1.445 V				O	300.0 µs
Line Volts Low (drop-off)	State 4	Driver 8 (Line Volts Low) 1->0	V L1-E		1.445 V				O	700.0 µs
Name/ Exec.	**Ramp**	**Condition**	**Sig**	**Nom.**	**Act.**	**Tol.-**	**Tol.+**	**Dev.**	**Assess**	**Tact**
Line Volts Low (pick-up)	State 1	Driver 8 (Line Volts Low) 0->1	V L2-E		1.514 V				O	600.0 µs
Line Dead (drop-off)	State 1	Driver 6 (Line Dead) 1->0	V L2-E		1.514 V				O	0.000 s
Line Volts High (pick-up)	State 2	Driver 7 (Line Volts High) 0->1	V L2-E		50.68 V				O	800.0 µs
Line Volts Low (drop-off)	State 2	Driver 8 (Line Volts Low) 1->0	V L2-E		50.68 V				O	200.0 µs
Line Volts Low (pick-up)	State 3	Driver 8 (Line Volts Low) 0->1	V L2-E		50.26 V				O	200.0 µs
Line Volts High (drop-off)	State 3	Driver 7 (Line Volts High) 1->0	V L2-E		50.26 V				O	600.0 µs
Line Dead (pick-up)	State 4	Driver 6 (Line Dead) 0->1	V L2-E		1.446 V				O	600.0 µs
Line Volts Low (drop-off)	State 4	Driver 8 (Line Volts Low) 1->0	V L2-E		1.446 V				O	0.000 s
Name/ Exec.	**Ramp**	**Condition**	**Sig**	**Nom.**	**Act.**	**Tol.-**	**Tol.+**	**Dev.**	**Assess**	**Tact**
Line Volts Low (pick-up)	State 1	Driver 8 (Line Volts Low) 0->1	V L3-E		1.492 V				O	200.0 µs
Line Dead (drop-off)	State 1	Driver 6 (Line Dead) 1->0	V L3-E		1.492 V				O	600.0 µs
Line Volts High (pick-up)	State 2	Driver 7 (Line Volts High) 0->1	V L3-E		50.69 V				O	100.0 µs
Line Volts Low (drop-off)	State 2	Driver 8 (Line Volts Low) 1->0	V L3-E		50.69 V				O	500.0 µs
Line Volts Low (pick-up)	State 3	Driver 8 (Line Volts Low) 0->1	V L3-E		50.27 V				O	800.0 µs
Line Volts High (drop-off)	State 3	Driver 7 (Line Volts High) 1->0	V L3-E		50.26 V				O	200.0 µs
Line Dead (pick-up)	State 4	Driver 6 (Line Dead) 0->1	V L3-E		1.455 V				O	100.0 µs
Line Volts Low (drop-off)	State 4	Driver 8 (Line Volts Low) 1->0	V L3-E		1.455 V				O	500.0 µs

Assess: + .. Passed x .. Failed o .. Not assessed

When the ladder diagram was compiled at Hydro One's Bay Street offices, it was considered prudent to ensure exercising of the delay timer (TMR) functionality, so a one second delay was included for inputs 1 to 16 – refer to Appendix D. However, as may be seen in Tables 5.3 and 5.4, this has the effect of reducing the resolution on the pick-up times so that variability in this parameter is less noticeable.

6 AGEING CYCLES

Three ageing cycles were to be conducted with any subsequent cycles depending on attained results. The ageing cycles with their respective post-ageing tests were conducted between 24 Jan 2011 and 19 Jan 2012.

Table 6.1 shows the composition of each PALC crate/card set subjected to the ageing cycles and Table 6.2 shows the ageing cycle detail.

Table 6.1 – PALC crate/card set composition

PALC #	125V-PSM	CPU	125V-I25	AIM	OR6	B	125V-OD27
1	01	01	01	01	01	-	01
2	02	02	02	02	02	-	02
3	03	03	03	03	03	-	03
4	04	04	04	04	04	-	04
5	05	05	05	05	05	-	05
6	06	06	06	06	06	-	06
7	07	07	07	07	07	-	07
8	08	08	08	08	-	08	08
9	09	09	09	09	-	09	09
10	10	10	10	10	-	10	10
11	11	11	11	11	-	11	11
12	12	12	12	12	-	12	12

Note: B-08 to B-12 are blank (PAC9) cards

Table 6.2 – Ageing cycles

AGEING CYCLE	FACILITY	START	END	DURATION	CYCLE DURATION
1	Walk-in thermal chamber	24 Jan	24 Feb	30.7 days	93.3 days
		14 Mar	26 Apr	42.7 days	
	Oven #1	30 Jun	20 Jul	19.9 days	
2	Oven #1	27 Jul	7 Aug	10.9 days	60.4 days
		8 Aug	31 Aug	22.6 days	
	Oven #6	6 Sep	3 Oct	26.9 days	
3	Oven #6	7 Oct	9 Nov	31.2 days	31.2 days

Cycle 1 was spread over 6 months because the environmental chamber was in great demand and all ovens were in use. Cycles 2 and 3 ran smoothly except when Oven #1 tripped on 7 Aug, and when it was required for another job after 31 Aug. The PALCs were transferred to Oven #6, which is much smaller, so the clearances between PALCs, as stipulated in the test procedure, could not be met; however, as discussed with Hydro One [5], this oven has forced convection mitigating the need for large clearances.

During the ageing cycles, all PALCs were powered up to 125 V and the LEDs for the CPU cards were switched on with the rotary switch on the “LED TEST” position. This was not possible for the I/O cards, as the DPDT switches do not latch in the “TEST” position. Daily checks confirmed chamber/oven temperature and continued functioning of the 12 PALC power supply modules.

Post-Ageing tests were conducted after each ageing cycle, although some informal checks were performed on the PALCs during down-time (specifically in Cycle 1).

7 POST-AGEING TESTS

The post-ageing tests are identical in format to the pre-ageing test but were only applied to the 12 PALC crate/card sets (Table 6.1). As before, OR6-01 was used to supplement Card Sets 8 to 12.

7.1 Post-Ageing Test (Cycle 1)

7.1.1 In-service configuration test

Two failures were found:

- **AIM-04**: Would not power up properly. Capacitor C21 was found to be short circuited and was replaced by a cluster of capacitors to get the correct value – refer to Figure 7.1.

Figure 7.1 – Faulty C21 and repaired AIM-04

This repair was necessary to continue the ageing cycles but could only be affected after the Omicron tests.

- **OR6-04**: Output 2 relay LED would not illuminate. Relay K2 coil was found to be open circuit and was replaced – refer to Figure 7.2.

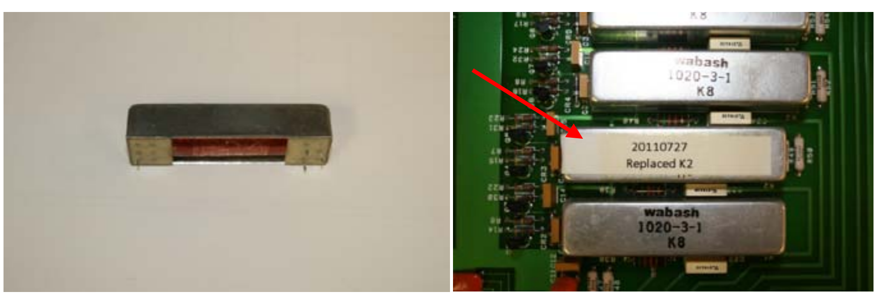


Figure 7.2 – Faulty relay and repaired OR6-04

This repair was necessary to complete the post-ageing test and continue with subsequent ageing cycles.

7.1.2 Power supply modules

Table 7.1 shows the output voltage results for the twelve 125 V crates when loaded at rated current.

Table 7.1 – PSM test results: Post-Ageing (Cycle 1)

CRATE	+5 V O/P	-5 V O/P	+12 V O/P
125V-PSM-01	4.87	-5.08	11.96
125V-PSM-02	4.89	-5.15	11.85
125V-PSM-03	5.08	-5.14	11.91
125V-PSM-04	5.00	-5.09	11.89
125V-PSM-05	4.87	-5.09	11.93
125V-PSM-06	4.74	-1.01	12.10
125V-PSM-07	5.06	-5.09	11.84
125V-PSM-08	5.11	-5.11	11.79
125V-PSM-09	4.80	-5.11	11.95
125V-PSM-10	4.85	-5.09	11.80
125V-PSM-11	4.77	-5.09	11.88
125V-PSM-12	5.00	-5.13	11.94

All voltage levels were within tolerance with the exception of:

- **125V-PSM-06**: The 5 V output was marginally beyond tolerance. The -5 V output could not supply the rated load and could not rise above 1 V. As this power supply module was still able to power up the PALC, it was decided to retain it for observation in the next ageing cycle.

7.1.3 Test-specific ladder diagram test (Omicron test)

AIM-01 was used as a temporary replacement for AIM-04 to ensure OD27-04 pick-up and drop-off timing could be recorded. Results are shown graphically in the analysis section. During this test, observations as per Table 7.2 were made, discussed further in the Analysis section of this report.

Table 7.2 – Observations during Omicron test: Post-Ageing Test (Cycle 1)

OBSERVATION	CARDS AFFECTED	# OF CARDS
For channel 1, the Line Volts Low (pick-up) value was far too low (8.002 mV).	AIM-03	1
For channels 1 and 2, the Line Volts Low (pick-up) values were far too low (8.002 mV).	AIM-06	1

7.2 Post-Ageing Test (Cycle 2)

7.2.1 In-service configuration test

One failure was found:

- **AIM-04**: As before, it would not power up properly. Capacitor C20 was found to be out of tolerance and was replaced by a cluster of capacitors to get the correct value – refer to Figure 7.3.

Figure 7.3 – Faulty C20 and repaired AIM-04

This repair was necessary to continue the ageing cycles but could only be affected after the Omicron tests.

7.2.2 Power supply module test

Table 7.3 shows the output voltage results for the twelve 125 V crates when loaded at rated current.

Table 7.3 – PSM test results: Post-Ageing (Cycle 2)

CRATE	+5 V O/P	-5 V O/P	+12 V O/P
125V-PSM-01	4.86	-5.08	11.95
125V-PSM-02	4.85	-5.18	11.81
125V-PSM-03	-	-	-
125V-PSM-04	5.04	-5.11	11.88
125V-PSM-05	4.83	-5.12	11.90
125V-PSM-06	4.78	-5.06	12.07
125V-PSM-07	5.05	-5.09	11.84
125V-PSM-08	5.17	-5.05	11.77
125V-PSM-09	4.79	-5.12	11.95
125V-PSM-10	4.85	-5.11	11.79
125V-PSM-11	4.77	-5.10	11.88
125V-PSM-12	4.93	-5.17	11.89

All voltage levels – even for PSM-06 – were within tolerance with the exception of:

- **125V-PSM-03**: Would not supply voltage on any of its outputs unless an AIM card was present in the crate. As this power supply module was still able to power up the PALC, it was decided to retain it for observation in the next ageing cycle.

For PSM-06, the result is surprising and indicates that it has an intermittent problem.

7.2.3 Test-specific ladder diagram test (Omicron test)

AIM-01 was used as a temporary replacement for AIM-04 to ensure OD27-04 pick-up and drop-off timing could be recorded. Results are shown graphically in the analysis section. During this test, observations as per Table 7.4 were made, discussed further in the Analysis section of this report.

Table 7.4 – Observations during Omicron test: Post-Ageing Test (Cycle 2)

OBSERVATION	CARDS AFFECTED	# OF CARDS
Toggle switch sticks on “Reset”. It is supposed to return to mid-position by itself.	CPU-02	1
For channels 1 and 3, the Line Volts Low (pick-up) values were far too low (8.002 mV).	AIM-06	1
Toggle switch sticks on “Test” position. It is supposed to return to “Blank” by itself.	OR6-06	1
LEDs would not illuminate during Omicron test until switch was toggled.	125V-I25-01 125V-I25-09	2
LEDs would not illuminate during Omicron test until switch was toggled a number of times.	125V-OD27-02 125V-I25-03 125V-OD27-03	3
LEDs would not illuminate during Omicron test until switch was toggled many times.	125V-OD27-09 125V-I25-10 125V-OD27-10 125V-I25-11 125V-I25-12	5

7.3 Post-Ageing Test (Cycle 3)

7.3.1 In-service configuration test

No failures were found. However AIM-04 is still problematic; it appears that the replacement of capacitors C21 and/or C20 – refer to Post-Ageing Test (Cycles 1 and 2) – was not wholly successful. The performance of the AIM card is quite sensitive to the tolerance of these capacitors. AIM-01 was temporarily used to ensure OD27-04 pick-up and drop-off timing could be recorded.

7.3.2 Power supply module test

Table 7.5 shows the output voltage results for the twelve 125 V crates when loaded at rated current.

Table 7.5 – PSM test results: Post-Ageing (Cycle 3)

CRATE	+5 V O/P	-5 V O/P	+12 V O/P
125V-PSM-01	4.84	-5.08	11.91
125V-PSM-02	4.86	-5.17	11.82
125V-PSM-03	-	-	-
125V-PSM-04	5.01	-5.10	11.88
125V-PSM-05	4.83	-5.11	11.87
125V-PSM-06	4.61	-3.84	12.05
125V-PSM-07	5.00	-5.10	11.81
125V-PSM-08	5.17	-5.11	11.78
125V-PSM-09	4.76	-5.13	11.94
125V-PSM-10	4.84	-5.06	11.78
125V-PSM-11	4.71	-5.11	11.74
125V-PSM-12	4.98	-5.11	11.91

All voltage levels were within tolerance with the exception of:

- **125V-PSM-03**: Would not supply voltage on any of its outputs unless an AIM card was present in the crate. However, when attempting to draw rated load, it emitted a high-pitched whine, then failed. Three burnt resistors were found – refer to Figure 7.4.

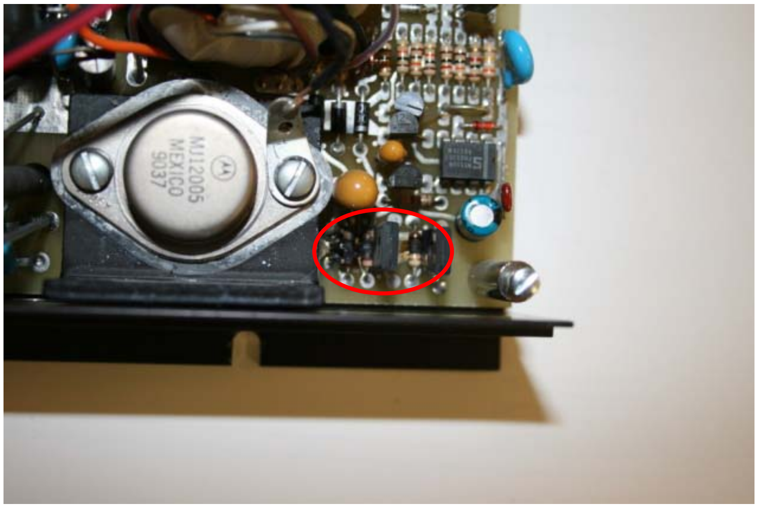


Figure 7.4 – 3x burnt resistors in PSM-03

This power supply module was problematic before – refer to Post-Ageing Test (Cycle 1). This failure is considered non-relevant because it occurred during the power supply test at rated load current – the power supplies are not subjected to rated current during normal use.

- **125V-PSM-06**: The -5 V output could not supply the rated load and could not rise above 3.84 V. Again this indicates an intermittent problem – refer to Post Ageing Test (Cycles 1 and 2).

7.3.3 Test-specific ladder diagram test (Omicron test)

AIM-01 was used as a temporary replacement for AIM-04 to ensure OD27-04 pick-up and drop-off timing could be recorded. Results are shown graphically in the analysis section. During this test, observations as per Table 7.6 were made discussed further in the Analysis section of this report.

Table 7.6 – Observations during Omicron test: Post-Ageing Test (Cycle 3)

OBSERVATION	CARDS AFFECTED	# OF CARDS
Toggle switch sticks on "Test" position. It is supposed to return to "Blank" by itself.	OR6-06	1
Switched off on its first ramp, i.e., Ramping 3-AIM.rmp but recovered when "Self-test" button was pressed	AIM-02	1
Toggle switch sticks on "Reset". It is supposed to return to mid-position by itself.	CPU-01 CPU-02	2
LEDs would not illuminate during Omicron test until switch was toggled a number of times.	125V-OD27-02 125V-I25-02	2
LEDs would not illuminate during Omicron test until switch was toggled.	125V-OD27-01 125V-I25-05 125V-I25-12	3
LEDs would not illuminate during Omicron test until switch was toggled many times.	125V-I25-09 125V-OD27-09 125V-I25-11	3

8 ANALYSIS

8.1 Assessment of PALCs against Reliability Target

Only relevant failures need to be considered. Table 8.1 provides a summary of the failures and indication of simulated age. Referring to section 3, the reliability target is R(X|20) > 70% with 90% confidence (single-tailed), where X = 5, 10 or 15 years. For the above reliability target, the maximum allowable number of failures is 0 for the OR6 card and 1 for all other cards and the Power Supply Module. Table 8.2 shows a decision matrix derived from the relevant failures – versus maximum allowed – that occurred during the ageing cycles.

Table 8.1 – Summary of relevant failures and simulated age

FAILURE #	CARD	DESCRIPTION	CYCLE	CUM. TESTING TIME	AF	SIMULATED AGE
1	AIM-04	Capacitor C21 short circuit	1	93.3 days	14.21	3.63 years
2	OR6-04	Relay K2 coil open circuit	1	93.3 days	2.50	0.64 years
3	AIM-04	Capacitor C20 out of tolerance	2	153.7 days	14.21	5.98 years

Note: “-04” suffix for both AIM and OR6 is a coincidence; they came out of different PALCs – refer to Appendix C.

Table 8.2 – Decision matrix for R(X|20) targets

<table>
<tr><th rowspan="3">PSM / CARD</th><th colspan="7">TARGET: R(X|20) > 70% with 90% confidence (single-tailed)</th></tr>
<tr><th rowspan="2">Max</th><th colspan="2">X = 5</th><th colspan="2">X = 10</th><th colspan="2">X = 15</th></tr>
<tr><th>Actual failed</th><th>Decision</th><th>Actual failed</th><th>Decision</th><th>Actual failed</th><th>Decision</th></tr>
<tr><td>Power Supply Module</td><td>1</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td></tr>
<tr><td>CPU (PAC3)</td><td>1</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td></tr>
<tr><td>Input (PAC25)</td><td>1</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td></tr>
<tr><td>AIM</td><td>1</td><td>1</td><td>Inconclusive</td><td>2</td><td>Not met</td><td>2</td><td>Not met</td></tr>
<tr><td>Output Relay (PAC6)</td><td>0</td><td>1</td><td>Not met</td><td>1</td><td>Not met</td><td>1</td><td>Not met</td></tr>
<tr><td>Output Driver (PAC27)</td><td>1</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td><td>0</td><td>Inconclusive</td></tr>
<tr><td colspan="2">OVERALL PALC</td><td></td><td>NOT MET</td><td></td><td>NOT MET</td><td></td><td>NOT MET</td></tr>
</table>

Notes:

1) “Max” is the maximum allowable for any X; actual failure numbers are cumulative over period X.
2) “Inconclusive” means that there was insufficient chamber/oven time for all components on a card to reach X years for a possible reliability target “Met” decision.

The overall PALC decision – that the PALC does not meet the target reliability for another 5 years – assumes equal representation of tested cards in the field. However it is understood that the PAC6 (Output Relay) cards are commonly used and, according to Table 8.2, it is this card that undermines the overall PALC reliability irrespective of X.

8.2 Performance or Degradation Modelling

The previous sub-section in essence considers success/failure testing to attempt to reach a “go/no-go” decision. Given the long length of chamber/oven time actually required to accelerate PALC life, results will tend to reflect “inconclusive” unless a “not met” decision is reached first.

Another possible method is to model product performance (or degradation) over time during testing, as would be benchmarked during the Pre-Ageing Test and then measured or observed during subsequent Post-Ageing Tests.

Three sets of measurements/observations were made in this accelerated life test:

- Power supply module output voltage measurements
- Omicron relay timing and voltage threshold measurements
- Qualitative observations of PALC performance

8.2.1 Power supply module measurements

Figures 8.1 to 8.3 show the performance of the +5, -5 and +12 V outputs of the 16 power supply modules, where the first 12 were subjected to the ageing test.

With the exception of 125V-PSM-13, 125V-PSM-14 and 250V-PSM-01 (spares), the measurement differences and apparent trends for each power supply module output could be due to measurement uncertainty but the following power supply modules exhibited clear signs of degradation:

- **125V-PSM-03**: Unable to provide voltage output during Post-Ageing Test (Cycles 2 & 3) unless AIM card was present – failed during the latter test.
- **125V-PSM-07**: +5V output was stable until a sudden decrease showed up in the Post-Ageing Test (Cycle 3) but the measurement was still well within the upper/lower bounds.
- **125V-PSM-11**: +5V and +12V outputs were very stable until a sudden decrease showed up in the Post-Ageing Test (Cycle 3) with the measurement below the lower bound for the +5V output but still well above the lower bound for the +12V output.

The outputs for all power supply modules remained within the upper/lower bounds with the exception of:

- **125V-PSM-06**: Intermittent performance of +5V and -5V outputs
- **250V-PSM-02**: Was meant to be a spare but failed during Pre-Ageing Test

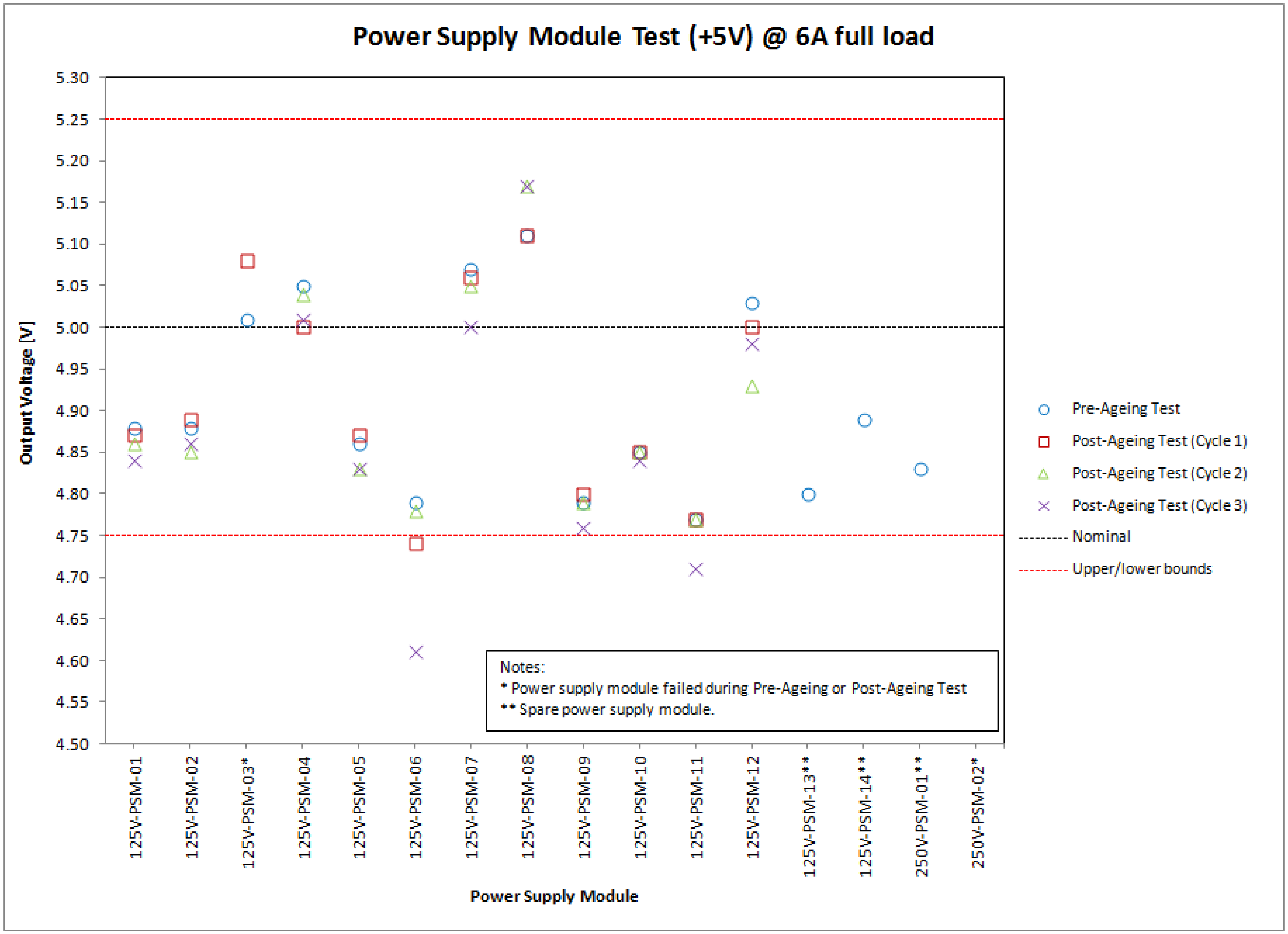


Figure 8.1 – PSM +5V output performance

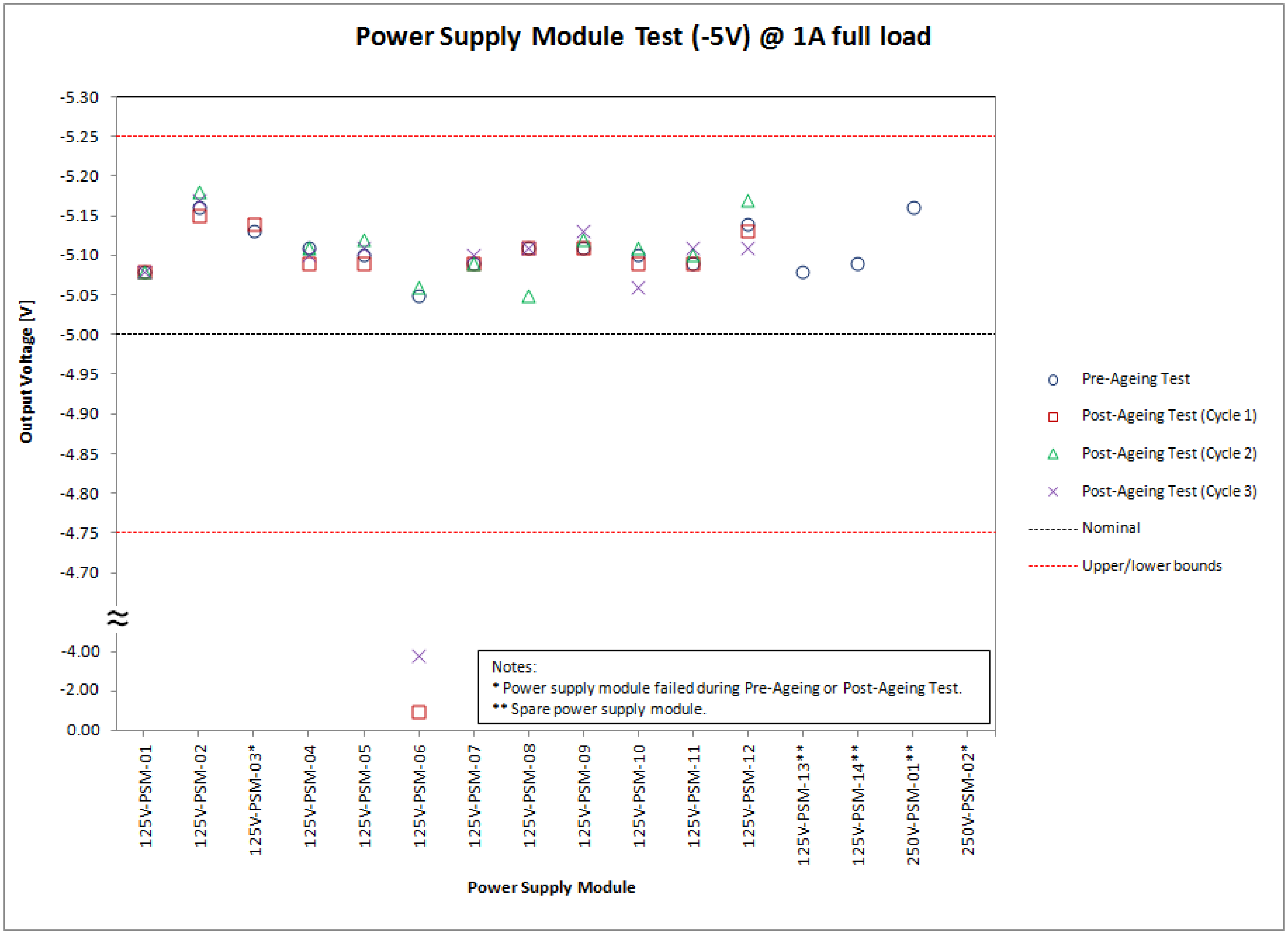


Figure 8.2 – PSM -5V output performance

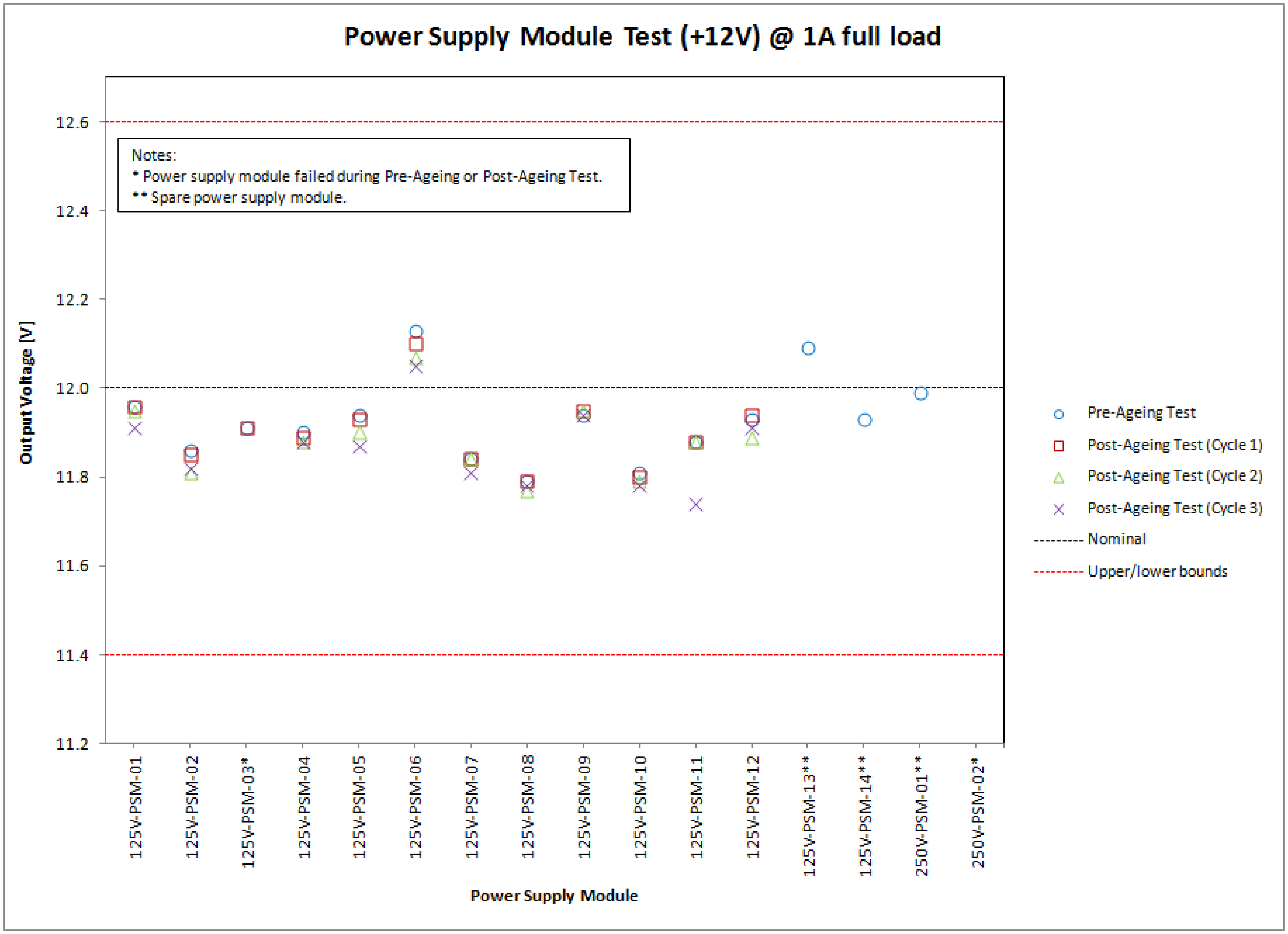


Figure 8.3 – PSM +12V output performance

8.2.2 Relay / output driver timing and voltage threshold measurements

All Omicron data is displayed graphically for convenience and is arranged according to the input-to-output paths that were tested, namely:

- PAC25 (Inputs 1 to 8) to PAC6 (Output Relays 1 to 8)
- PAC25 (Inputs 9 to 16) to PAC27/PAC7 (Output Drivers 1 to 4)
- AIM (Inputs 1 to 3) to PAC27/PAC7 (Output Drivers 6 to 8)

8.2.2.1 PAC25 (Inputs 1 to 8) to PAC6 (Output Relays 1 to 8)

Figure 8.4 shows the pick-up time per card set. Little variability in the results is noticeable because the 1 second timer delay, contained in the ladder diagram, has decreased timing measurement resolution.

Figure 8.5 shows the drop-off time per card set. The range of values for Card Sets 15 and 16 is somewhat higher than the rest but these two card sets are for 250 V as opposed to 125 V for the rest. The timing ranges for Card Set 4 is most spread compared to Card Sets 3, 7 and the rest of the 125 V card sets. Most card sets exhibit a downward trend with an upswing in the last post-ageing test. Further ageing cycles would be required to detect degradation.

8.2.2.2 PAC25 (Inputs 9 to 16) to PAC27/PAC7 (Output Drivers 1 to 4)

Figure 8.6 shows the pick-up time per card set. Little variability in the results is noticeable because the 1 second timer delay contained in the ladder diagram has decreased timing measurement resolution.

Figure 8.7 shows the drop-off time per card set. Most card sets exhibit a downward trend from Pre-Ageing Test to Post-Ageing Test (Cycle 1) – at 3 months, Cycle 1 was the longest – levelling out thereafter. Degradation is not apparent – further ageing cycles would be required to detect degradation.

8.2.2.3 AIM (Inputs 1 to 3) to PAC27/PAC7 (Output Drivers 6 to 8)

Figures 8.8 and 8.9 respectively show the dead-to-low and low-to-dead voltage thresholds per card set. Excepting Card Sets 3 and 6 where dead-to-low voltage threshold dropped to 8.002 mV on five occasions, the spread in voltage threshold range is quite narrow. Note that the difference in thresholds between the two figures is due to hysteresis. There is no indication of performance degradation.

Figures 8.10 and 8.11 respectively show the low-to-high and high-to-low voltage threshold per card set. The spread in voltage threshold range is generally quite narrow with the notable exception of Card Set 7, which appears to be somewhat unstable. Note that the difference in thresholds between the two figures is due to hysteresis. There is no indication of performance degradation.

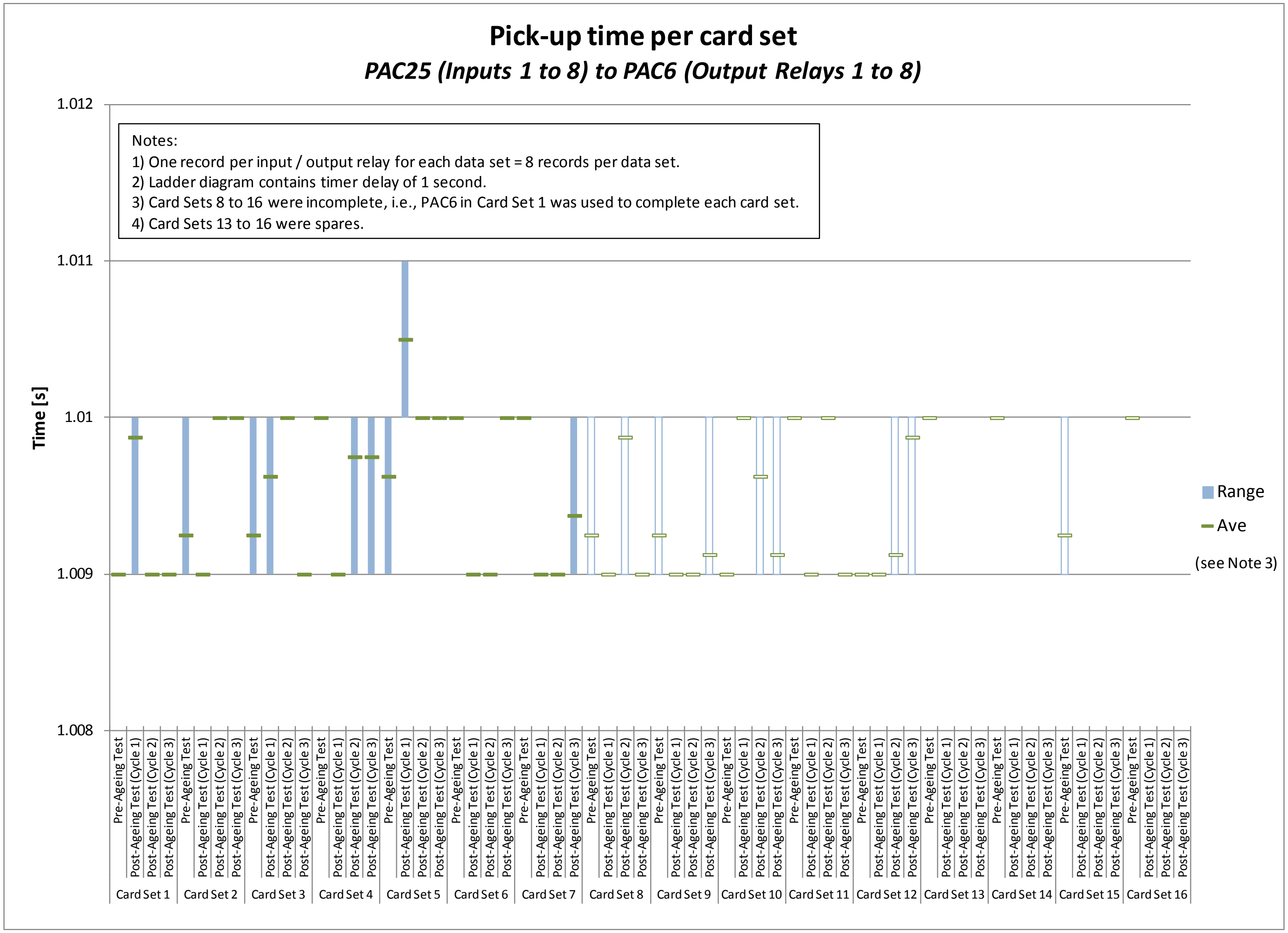


Figure 8.4 – Pick-up time (PAC25 to PAC6)

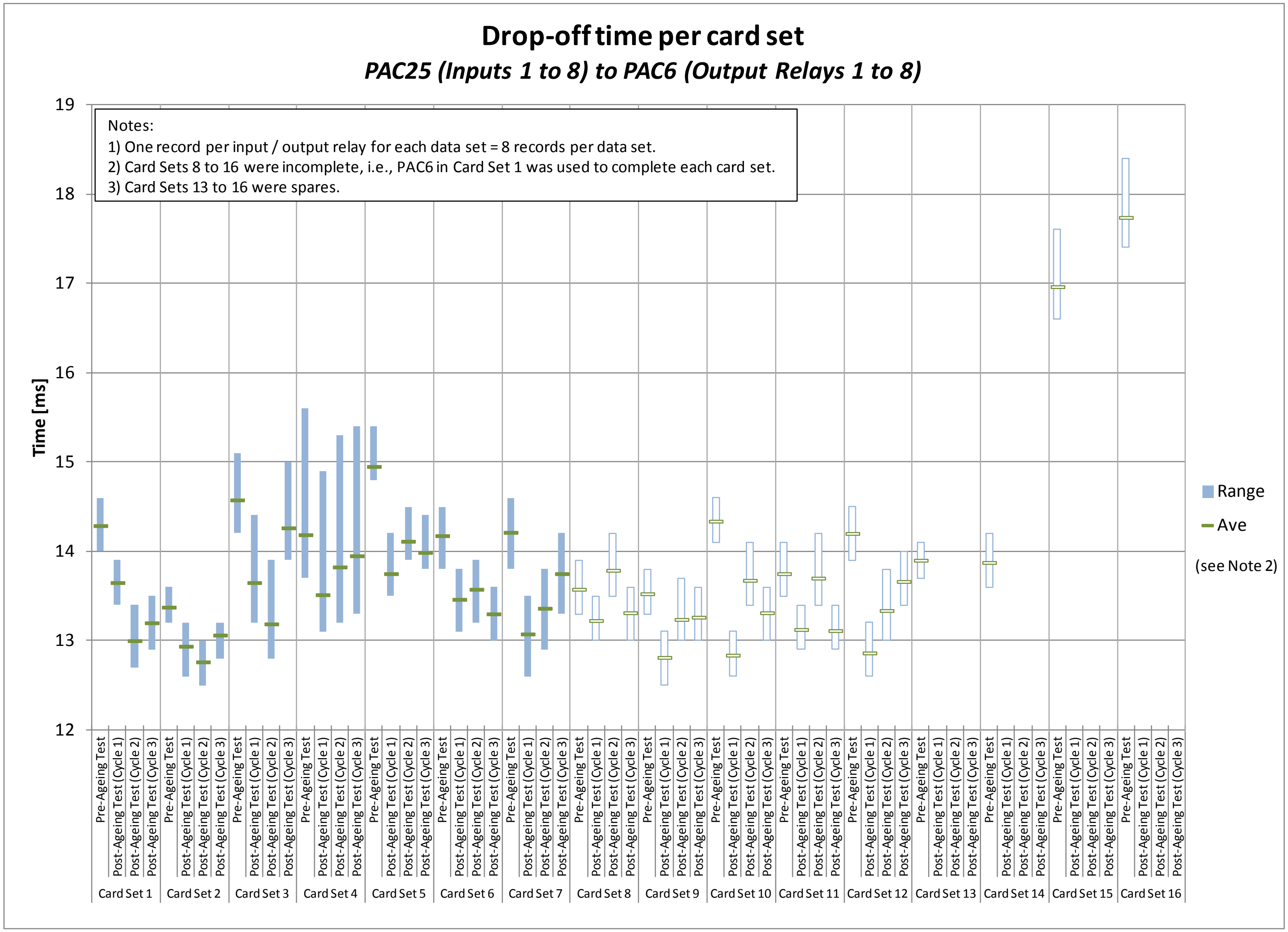


Figure 8.5 – Drop-off times (PAC25 to PAC6)

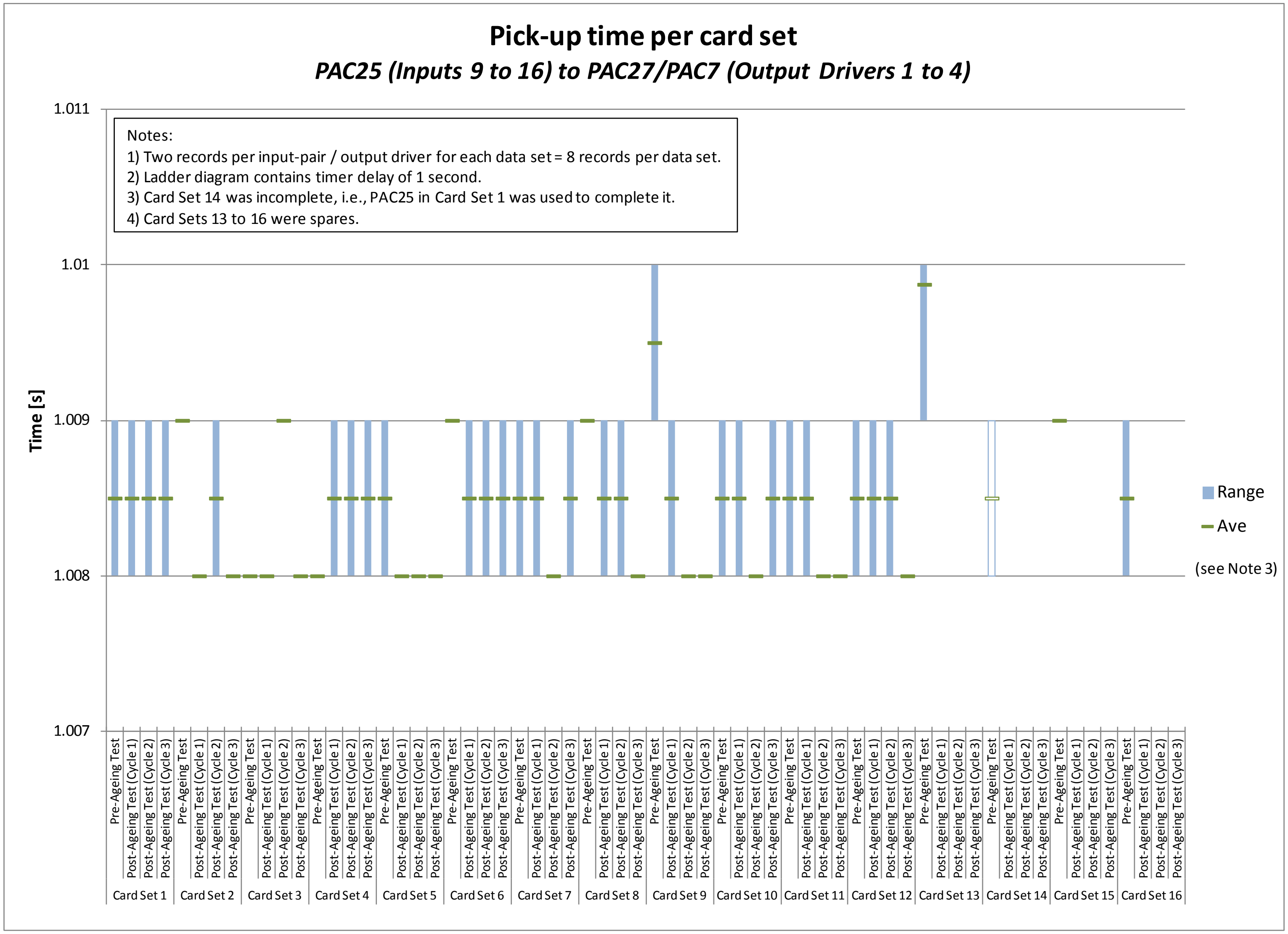


Figure 8.6 – Pick-up time (PAC25 to PAC27/PAC7)

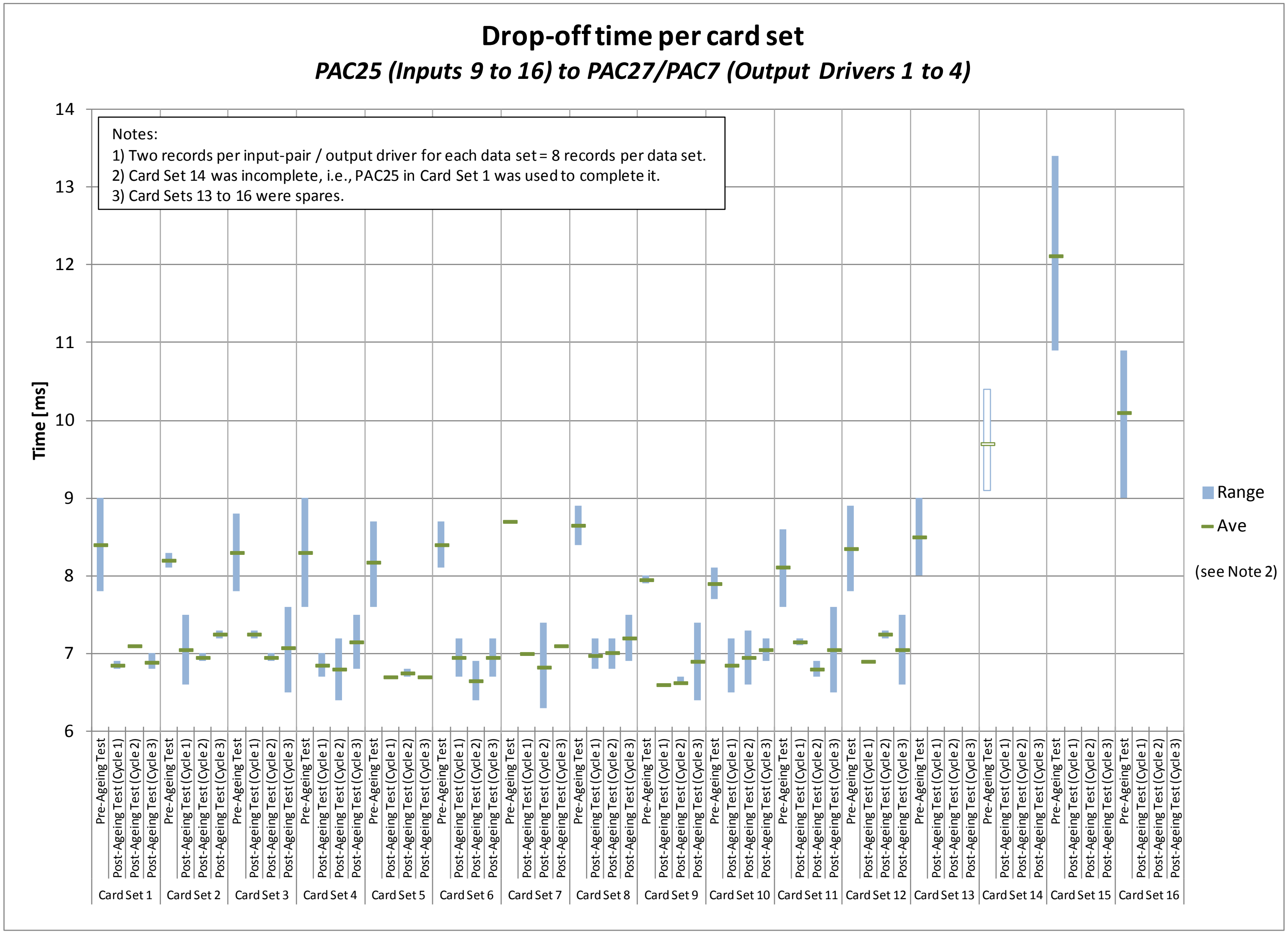


Figure 8.7 – Drop-off time (PAC25 to PAC27/PAC7)

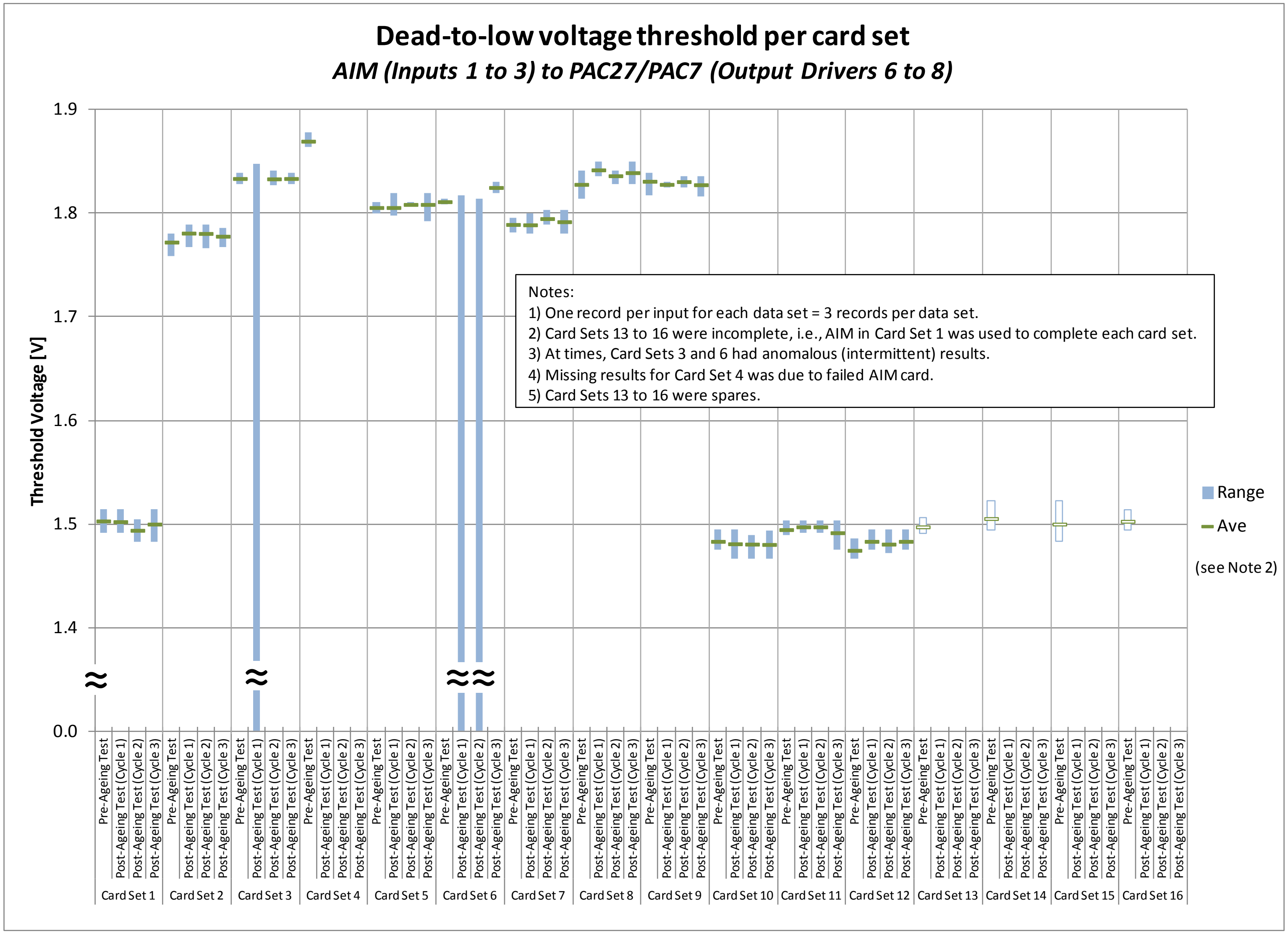


Figure 8.8 – Dead-to-low voltage threshold (AIM to PAC27/PAC7)

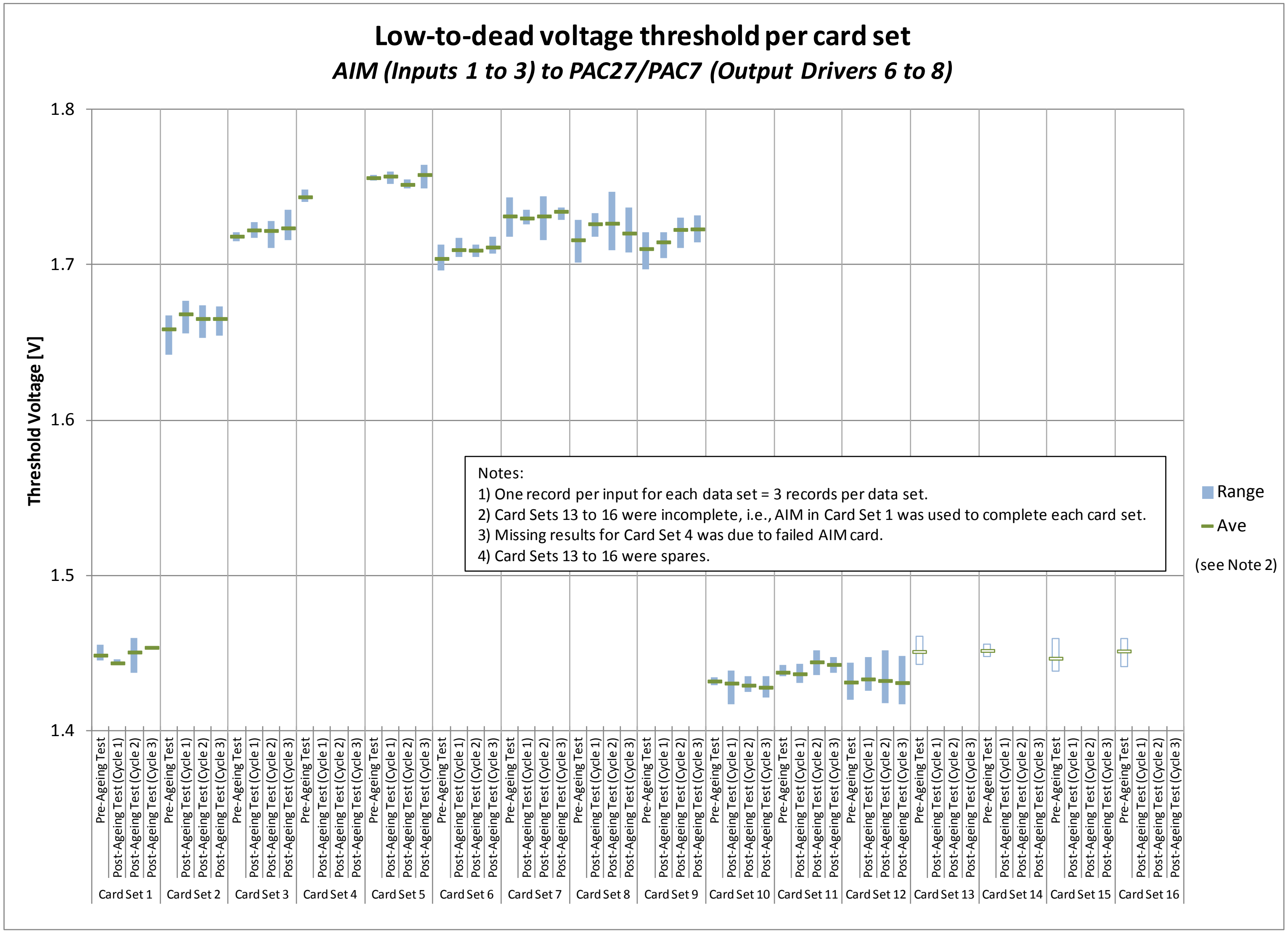


Figure 8.9 – Low-to-dead voltage threshold (AIM to PAC27/PAC7)

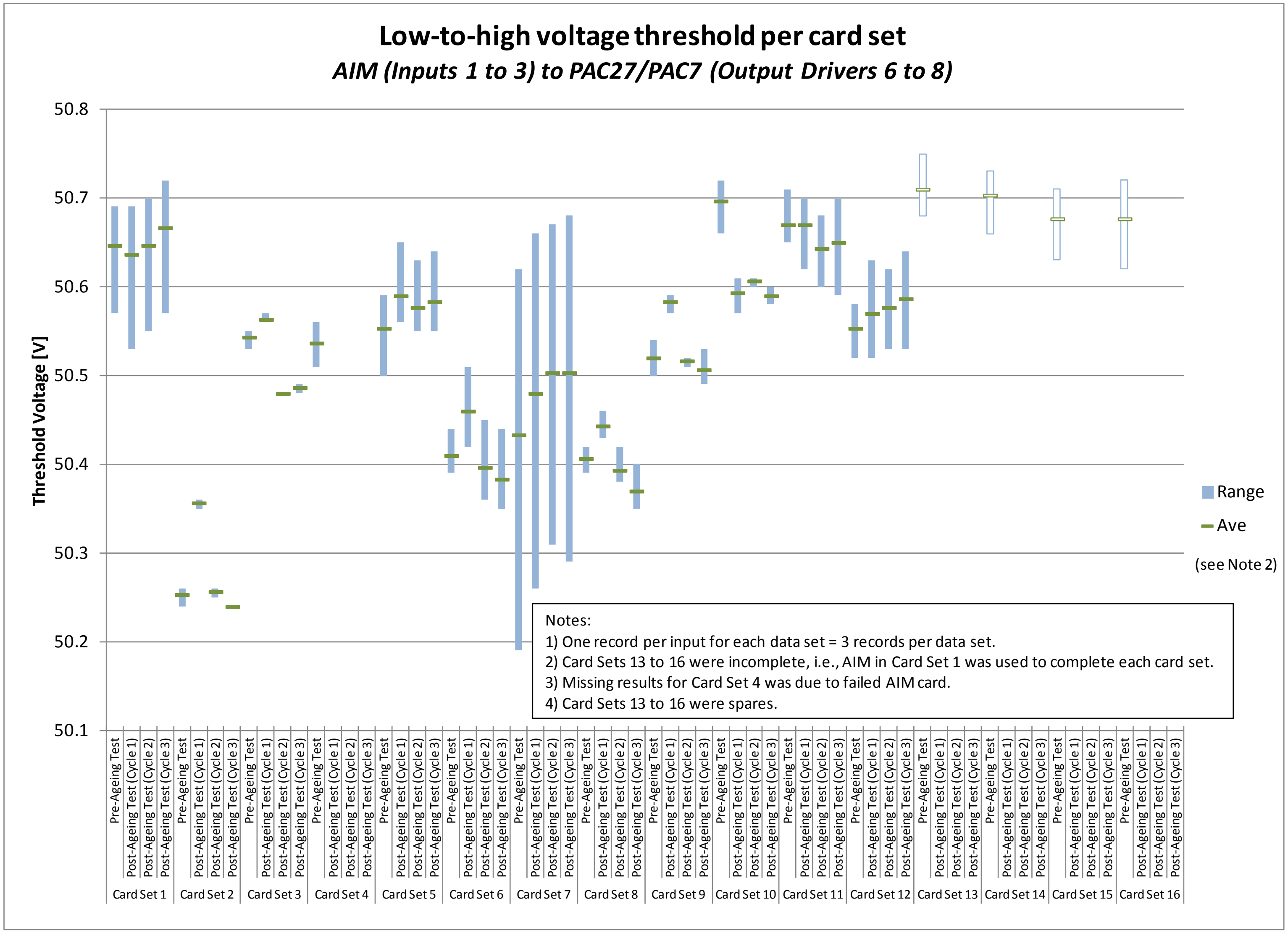


Figure 8.10 – Low-to-high voltage threshold (AIM to PAC27/PAC7)

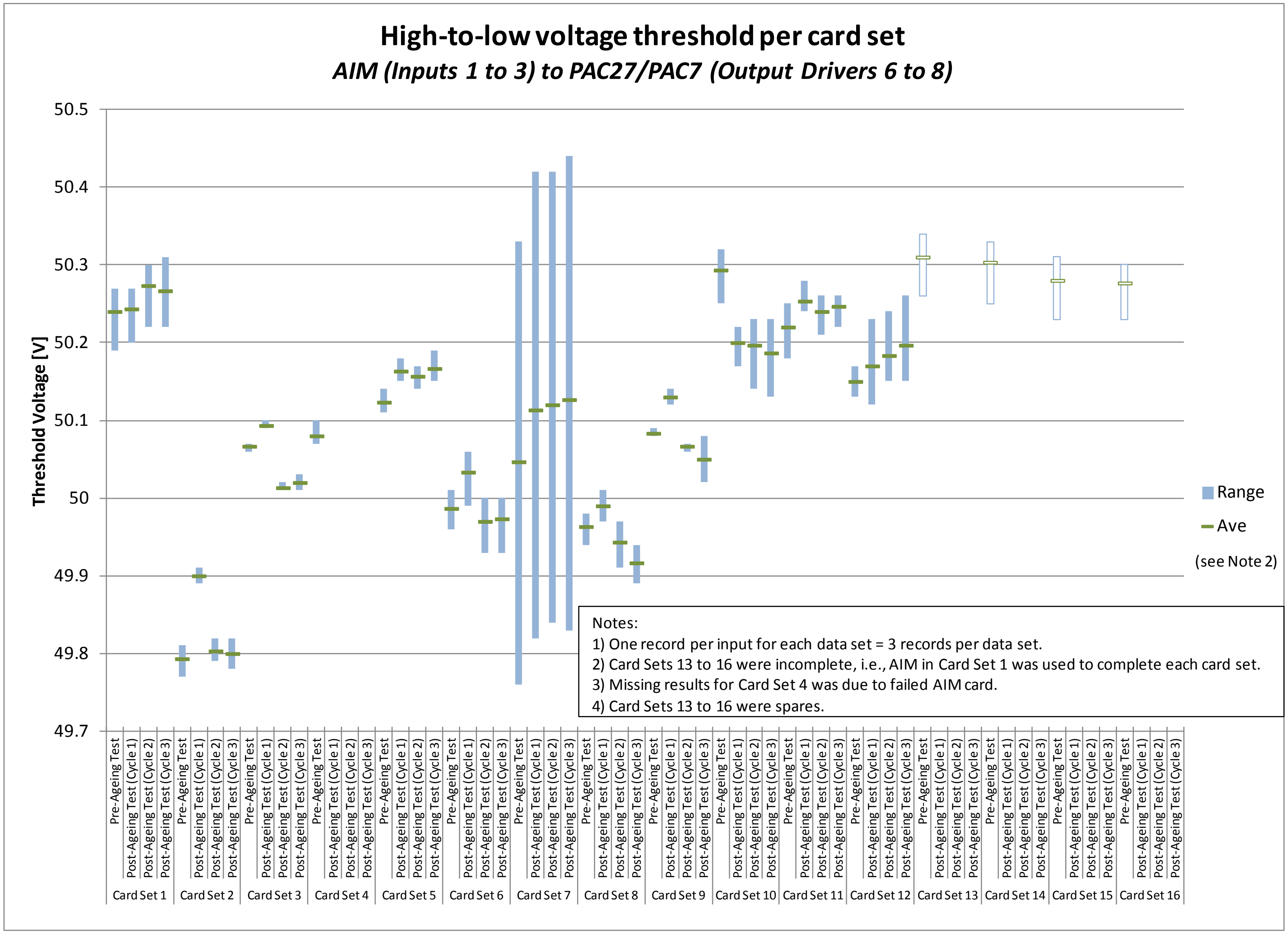


Figure 8.11 – High-to-low voltage threshold (AIM to PAC27/PAC7)

8.2.3 Qualitative observations of PALC performance

AIM-03 and AIM-06 experienced five cases between them where the Line Volts Low (pick-up) value was too low (8.002 mV) for one or more input channels; this was not an indication of performance degradation but intermittent behaviour.

The various SPDT switches exhibited performance degradation – either bad electrical contact or mechanically stiff – in that none was noticeable during the Pre-Ageing Test and the 1st post-ageing test, whereas there were respectively 12 and 11 cases (some repeats) in the 2nd and 3rd post-ageing tests. Toggling the switches restores their function for a while. However, the performance of the switches does not affect the day-to-day operation of the PALCs.

9 CONCLUSIONS

Unless a particular failure mode – in a complex, multi-component product – is being targeted for which an accelerated life test would specifically be designed, then accelerating the age of the product is not a trivial matter because there are limitations in the types of stresses and their levels that may be applied if one is to avoid non-relevant failure modes. An example of such a limitation is the maximum test temperature that may not exceed any component's maximum rating – for the PALC this is 70 °C. An example of a non-relevant failure mode would be one that would never occur during normal use, and the issue of non-relevant failures is especially acute if there is a scarcity of available test items – such as for the PALC.

Consequently, the relatively low allowable test temperature yields a low average acceleration factor requiring a lengthy 12-month test to simulate 5 years. However, different component categories have different acceleration factors allowing an acceleration factor granularity concept to be applied. This allows relatively early reliability assessment decisions to be made despite the fact that individual cards or indeed the entire PALC have not yet been aged by another 5 or more years.

This accelerated life test demonstrated that Hydro One's PALC population will not survive another 5 years of trouble-free operation, and this must be factored into Hydro One's asset management strategy. This statement – and in particular the term "trouble-free" – is further qualified if it is borne in mind that the selected reliability target of $R(X|20) > 70\%$ is not particularly stringent, but one that may be considered appropriate if Hydro One is to repair and/or replace PALCs, as and when failures occur. Whereas the result is clear at PALC level, further testing would be required in view of inconclusive results at individual card level should definitive “met / not met” reliability assessment decisions be required at card level.

10 RECOMMENDATIONS

Given the relatively non-stringent reliability target of R(X|20) > 70%, PALCs utilising Output Relay cards should be replaced within the next 5 years, whereas PALCs utilising AIM cards should be replaced within the next 10 years.

Additional accelerated ageing cycles would help to eliminate the “inconclusive” results at individual card level for cards other than Output Relay and AIM.

PALCs could be given a longer lease on life through refurbishment of Output Relay cards and AIM cards. Kinectrics could provide this service given in-house knowledge and expertise on PALCs, and new cards could be made if necessary.

It would be useful to compare test results to field-failure statistics; presumably these exist at Hydro One’s Meter and Relay Services.

Alternative means to increase acceleration factor – without introducing non-relevant failure modes – need to be explored.

11 ACKNOWLEDGEMENTS

The assistance of the following persons for various phases of the work is gratefully acknowledged:

- Andrea Valenca – Hydro One
- Warren Tingle – Hydro One
- Ron Bosyj – Hydro One
- John Neu – Hydro One
- Bob Beresh – Kinectrics
- Tom Gough - Kinectrics
- Corinne Dimnik – Kinectrics
- Mike Colbert – Kinectrics
- Adis Dzehverovic – Kinectrics
- Bert Grespan – Kinectrics
- Steve Cress - Kinectrics

12 REFERENCES

1. Koert, A., *Scope of Work - Accelerated Life Test: Programmable Auxiliary Logic Controllers (PALCs)*, 6 July 2010.
2. MIL-HDBK-217F:1991, *Reliability Prediction of Electronic Equipment*, Military Handbook.
3. IEC 61709:2010, *Electronic components – Reliability – Reference conditions for failure rates and stress models for conversion*, Ed. 2.0, Committee Draft for Vote 56/1323/CDV, International Electrotechnical Commission.
4. Valenca, A., Anandakumaran, A., *Accelerated Life Testing - IRX relay*, Kinectrics Report No.: K-014802-RA-0001-R0, Hydro One Report No.: PR-90-020-R0, March 2010.
5. E-mail from A. Koert to A. Valenca, followed up with telephone conversation, 31 August 2011.

13 BIBLIOGRAPHY

1. Wasserman, G.S., *Reliability Verification, Testing, and Analysis in Engineering Design*, Marcel Dekker Inc., 2003.
2. Nelson, W., *Accelerated Testing: Statistical Models, Test Plans, and Data Analyses*, John Wiley & Sons, 1989.
3. Pecht, M. (editor), *Product Reliability, Maintainability, and Supportability Handbook*, 2nd edition, CRC Press.

14 APPENDIX A: TEST PROCEDURE

Accelerated Life Test: Programmable Auxiliary Logic Controllers (PALCs)

TABLE OF CONTENTS Page

A0 OVERVIEW	46
A1 TEST BATCH PREPARATION	47
A2 PRE-AGEING TEST	48
A3 AGEING CYCLE	51
A4 POST-AGEING CYCLE TEST	52
A5 REFERENCES	52

LIST OF FIGURES Page

Figure A1 - Accelerated Life Test process block diagram	46

LIST OF TABLES Page

Table A1 - Jumper configurations for 0 to 150 Vac input (AIM card)	55
Table A2 - DIP switch settings for 50 V limit CVP functionality (AIM card)	55

A0 OVERVIEW

This document presents a stand-alone test procedure for the conduction of an Accelerated Life Test on Programmable Auxiliary Logic Controllers (PALCs). The aim of the test is to demonstrate that Hydro One's 20-year old PALC population has a probability of 70% -- with a single-tailed confidence level of 90% -- of surviving a further 5 years.

The acceleration mechanism is elevated temperature, as per the Arrhenius reaction rate model:

$$AF = e^{\frac{E_a}{k}\left(\frac{1}{T_u} - \frac{1}{T_s}\right)}$$

where:

AF is acceleration factor
E_a is activation energy
k is Boltzmann's constant (8.617×10^{-5} eV/K)
T_u is normal-use temperature (K)
T_s is stress temperature (K)

Different component categories (resistors, polycarbonate capacitors, polyester capacitors, ICs, tantalum capacitors etc.) have different activation energies, and will age at different accelerated rates when subjected to elevated (stress) temperature. Therefore the concept of AF granularity is applied in this test, i.e., the component category with the highest AF determines the minimum test time for this component category to reach 5 simulated years. The minimum test time is the duration of the 1st Ageing Cycle. Subsequent Ageing Cycle lengths are determined by component categories with successively lower AFs.

Figure A1 shows the testing process; each of the blocks is described in the subsections below.

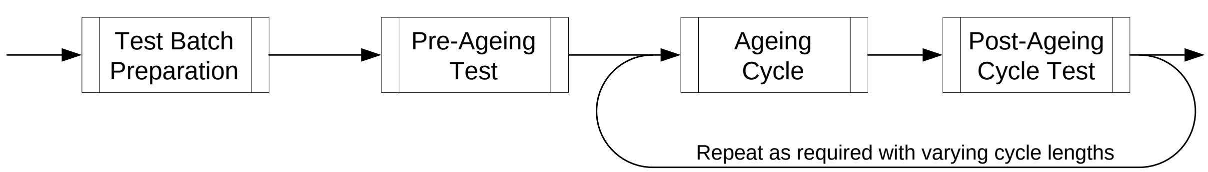


Figure A1 – Accelerated Life Test process block diagram

A1 TEST BATCH PREPARATION

A1.1 Test Batch Labelling

A complete PALC comprises a rack (or crate) incorporating a Power Supply Module, a CPU card and a set of I/O cards. Perform the following steps for each crate and, where applicable, for any individual cards:

a) Group the crates according to supply voltage, e.g., 48 Vdc, 125 Vdc, 250 Vdc. The supply voltage may be ascertained by inspecting the warning sticker on the printed circuit board for the Input cards and/or Output Driver cards.

b) For each sub-group of crates, label each crate as <ProjectNo>-<Voltage>-PSM-01, 02, 03 etc.

c) Label all constituent cards as follows:

- CPU: <ProjectNo>-CPU-01, 02, 03 etc.
- CPU EPROM: <ProjectNo>-CPUE-01, 02, 03 etc.
- Input: <ProjectNo>-<Voltage>-I<PACNo>-01, 02, 03 etc.
- AIM: <ProjectNo>-AIM-01, 02, 03 etc.
- Output Relay: <ProjectNo>-OR<PACNo>-01, 02, 03 etc.
- Output Driver: <ProjectNo>-<Voltage>OD<PACNo>-01, 02, 03 etc.

d) For each crate, record its label and serial number, and record the labels and serial numbers of its constituent cards in its existing (installation) card configuration.

e) Label all spare cards as per c) above by continuing the labelling sequence.

A1.2 Visual Inspection

For each crate, remove and visually inspect each card for signs of damage or deterioration; record the findings and repair if necessary. Re-populate each crate according to its in-service card configuration.

Visually inspect all spare cards for signs of damage or deterioration; record the findings and repair if necessary.

A1.3 Card Configurations

All Input cards (PAC5/PAC25) must be configured for 16 single-ended inputs by:

- Removing all jumpers JB1 to JB8
- Inserting all jumpers JA1 to JA16

All AIM cards must configured for 0 to 150 Vac input and Current and Voltage Protection (CVP) functionality with a voltage limit setting of 50 V per channel, as per Table A1 and A2. CVP functionality uses all three channels as opposed to the other standard AIM functions that use Channels 1 and 2 only.

Table A1 – Jumper configurations for 0 to 150 Vac input (AIM card)

CHANNEL 1	CHANNEL 2	CHANNEL 3
J11 in	J21 in	J31 in
J12 in	J22 in	J32 in
J13 in	J23 in	J33 in
J14 in	J24 in	J34 in
J15 out	J25 out	J35 out
J16 out	J26 out	J36 out
J17 out	J27 out	J37 out
J18 out	J28 out	J38 out

Table A2 – DIP switch settings for 50 V limit CVP functionality (AIM card)

BIT	1	2	3	4	5	6	7	8
SW1	0	1	0	1	0	1	0	1
SW2	0	1	0	1	0	0	0	0

Note: “0” = switch open; “1” = switch closed

A2 PRE-AGEING TEST

The purpose of this test is to ascertain whether each PALC -- crate and constituent cards, as per existing (in-service) card configuration -- and any spare cards are in working order upon delivery to Kinectrics and prior to the ageing cycle(s). More specifically, the pick-up and drop-out times for the cards are measured to serve as a benchmark against which deterioration through ageing may be assessed.

A2.1 In-service Configuration Test

For each crate in turn:

a) Power up the crate to its rated voltage (48 Vdc, 125 Vdc or 250 Vdc) via the BATTERY terminals on the rear of the PALC.

b) For each card, verify that the controls, i.e., knobs, toggle switches and push-button switches perform their function for all positions and that all LEDs illuminate as required. Note: If the CPU card indicates an I/O error, this could mean that one or more I/O cards are in the wrong slot or are faulty, as the in-service card configuration is stored on the CPU EPROM (PAC4) module.

c) Check the normally-closed ALARM contact on PALC rear by performing a PALC power down/power up.

d) If an AIM card is present, check the normally closed AIM contacts (terminals 13 & 14 and terminals 15 & 16 on the appropriate I/O slot terminal on PALC rear) by pressing the push button switch.

e) Keep failed cards separate; these may need to be repaired to meet the preferred sample size.

A2.2 Power Supply Module Test

For each crate in turn:

a) Remove all cards and insert test jig into CPU slot (upper socket). *Refer to Appendix B4.1 for detail on the test jig.*

b) Power up the crate to its rated voltage (48 Vdc, 125 Vdc or 250 Vdc) via the BATTERY terminals on the rear of the PALC.

c) Adjust load resistors R1 to R3 to load the supply as tabled below and record the output voltage. Confirm that the output voltage remains within the given limits. Using an oscilloscope, measure and record ripple levels for each output.

OUTPUT LOADING	OUTPUT VOLTAGE
6 A ± 0.2 A	+5 V ± 0.25 V
1 A ± 0.1 A	-5 V ± 0.25 V
1 A ± 0.1 A	+12 V ± 0.6 V

d) Power down and remove test jig. Keep failed crates separate; these may need to be repaired to meet the preferred sample size.

A2.3 Test-specific Ladder Diagram Test

Arrange with Hydro One for an EPROM (PAC4) card to be programmed with a suitable ladder diagram that uses a standard PALC configuration and ensures a timing relationship between all I/O inputs and outputs. *Refer to Appendix B2 and B4.4 for the standard PALC configuration and an example of a suitable ladder diagram.*

Perform the following steps:

a) Prepare a standard table of all PALC cards to be tested together as per the standard PALC configuration. It is suggested that cards ending in -01 (and of the same voltage rating where applicable) form the first set, similarly cards ending in -02 form the second set and so on. When there are insufficient cards of a certain type, use the first card (of the same voltage rating where applicable) for all remaining sets. It is important to keep a record of the PALC card sets, as this must be repeated where possible for each Post-Ageing Cycle Test to allow consistent before-and-after comparisons.

b) Wire an empty 48 Vdc crate to the Omicron CMC 256-6. *Refer to Appendix B4.2 and B4.3 for the PALC/Omicron interconnections and I/O Slot 5 test jig.*

c) Using the Omicron State Sequencer application, set up the profiles for Binary Outputs 1 to 4. *Refer to Appendix B4.5 for an example of profiles appropriate for the ladder diagram in Appendix B4.3*.

d) Using the Omicron Ramp application, set up the profile for Voltage Outputs 1 to 3. *Refer to Appendix B4.5 for an example of a profile appropriate for the ladder diagram in Appendix B4.3.*

e) For each card set containing 48 Vdc Input and/or Output Driver cards, set the Aux DC supply to 48 Vdc, run the Binary Outputs 1 to 4 profiles and run the Voltage Output 1 to 3 profiles one at a time. Observe the illumination and extinguishing of LEDs on the I/O cards and record the results. Generate the relevant reports using the Omicron report application in each case.

f) Repeat steps b) and e) above for 125 Vdc.

g) Repeat steps b) and e) above for 250 Vdc.

h) Keep failed cards separate; these may need to be repaired to meet the preferred sample size.

To meet the reliability target stated in section A0, the preferred sample size is 12, allowing for one relevant failure during the ageing cycle(s). The minimum sample size is seven, for which zero relevant failures are allowed during the ageing cycle(s).

If the sample size -- crate and/or constituent cards -- has fallen[1] below seven, and there are no spares, then the reliability target and/or single-tailed confidence level will need to be relaxed. Such considerations are beyond the scope of this test procedure, but must be resolved with Hydro One before commencing with the ageing cycle(s).

A3 AGEING CYCLE

Perform the following steps:

a) Measure the crate power supply current for a representative crate from each supply voltage group and determine the total power source requirements.

b) Using the standard table prepared in section A2.4, populate the 12 PALC crates as per the standard PALC configuration. Where there are insufficient cards, use a blank card.

c) Place the 12 PALCs in the thermal walk-in chamber, ensuring a minimum clearance of 15 cm surrounding each PALC in all directions.

d) Connect the PALCs to the appropriate dc power supply(ies).

e) Set up a temperature data acquisition system to monitor chamber temperature. *Refer to Appendix B5.1 for more detail on the temperature data acquisition system.*

f) For each PALC, insert test jig into I/O Slot 5 (upper socket) and feed the other end through chamber port. *Refer to Appendix B5.2 for detail on this power supply monitoring test jig.*

g) Switch on all power supplies.

h) Increase chamber temperature from ambient to 70 °C at a rate not exceeding 0.5 °C/min.

i) Seal door and maintain chamber temperature as per predetermined Ageing Cycle duration, e.g., 3 months. During this period, the following must be checked twice daily (weekends and statutory holidays excepted):

   - Chamber temperature
   - Power supply output for all PALC crates (via I/O Slot 5 test jig)

[1] One or more PALC cards could be found to be faulty prior to commencement of the Ageing Test.

j) Decrease chamber temperature from 70 °C to ambient at a rate not exceeding 0.5 °C/min.

k) Unseal door and remove PALCs from chamber.

Note: If a PALC crate power supply is found to be failed at any point during the Ageing Cycle, decrease chamber temperature from 70 °C to ambient at a rate not exceeding 0.5 °C/min., repair crate power supply or transfer constituent cards to a spare PALC crate, and increase chamber temperature from ambient to 70 °C at a rate not exceeding 0.5 °C/min. Make allowance for additional chamber test time.

A4 POST-AGEING CYCLE TEST

The purpose of this test is to ascertain whether each PALC -- crate and its constituent cards -- is in working order following an ageing cycle.

Follow all steps as per section A2 Pre-Ageing Test and compare results to Pre-Ageing Test results and any previous Post-Ageing Cycle Test results in terms of degradation/deterioration. Analyse any failures as to what component has failed and whether it is relevant. If possible, repair any non-relevant failures.

If a further Ageing Cycle is required, determine length of Ageing Cycle in terms of AF granularity and repeat from section A3 Ageing Cycle.

A5 REFERENCES

1. Whitmell, H.E., *Programmable Auxiliary Logic Controller Technical Reference Manual*, Ontario Hydro Research Division, Report No. E6-M-1991-H, Jan. 1993.
2. Kemp, A.R., *PALC Analog Input Module Technical Reference Manual*, Ontario Power Generation, OPT Report: 7259-110-1999-RA-001-R00, Nov. 1999.

15 APPENDIX B: TEST SET-UP

Accelerated Life Test: Programmable Auxiliary Logic Controllers (PALCs)

TABLE OF CONTENTS Page

B0 OVERVIEW	54
B1 EQUIPMENT REQUIREMENTS	54
B2 PALC CONFIGURATION	54
B3 PRE-AGEING / POST-AGEING CYCLE TEST SET-UP	55
B4 AGEING CYCLE SET-UP	56

LIST OF FIGURES Page

Figure B1 - PALC configuration	57
Figure B2 - CPU slot test jig	58
Figure B3 - PALC / Omicron CMC 256-6 interconnections	59
Figure B4 - I/O Slot 5 test jig (8-pole, 12 Vdc relay supply)	60
Figure B5 - Test ladder diagram	61
Figure B6 – Omicron CMC 256-6 Binary Output profiles	63
Figure B7 – Omicron CMC 256-6 Voltage Output profile (per channel)	64
Figure B8 - I/O Slot 5 test jig (power supply monitoring)	65

LIST OF TABLES Page

Table B1 - Equipment requirements	54

B0 OVERVIEW

This document details the test set-up for the conduction of the Accelerated Life Test on Programmable Auxiliary Logic Controllers (PALCs), as outlined in Appendix A.

B1 EQUIPMENT REQUIREMENTS

Table B1 presents a list (or summary) of equipment required for the tests outlined in the test procedure. Further detail is provided in the sections below.

Table B1 – Equipment requirements

#	DESCRIPTION	QTY
1	Variable dc power supply 0 to 275 Vdc, 1 A continuous, 5 A inrush	1
2	Digital 4½ digit voltmeter	1
3	Ammeter, 0 to 10 A, 1% accuracy	3
4	CPU slot test jig (refer to Figure B2)	1
5	Omicron CMC 256-6 (refer to Figure B3) and software	1
6	Suitably terminated wiring harnesses for PALC / Omicron interconnections	-
7	8-pole, 12 Vdc relay board (refer to Figure B3)	1
8	I/O Slot 5 test jig (refer to Figure B4)	1
9	CPU EPROM (PAC4) with test ladder diagram (refer to Figure B5)	1
10	Thermal walk-in chamber	1
11	48 Vdc power supply (further specifications to be determined)	TBD
12	125 Vdc power supply (further specifications to be determined)	TBD
13	250 Vdc power supply (further specifications to be determined)	TBD
14	I/O Slot 5 test jig (refer to Figure B7)	12
15	Chamber temperature data acquisition system	1

B2 PALC CONFIGURATION

Figure B1 shows the required PALC configuration. Note that:

(i) Each crate must contain no more than one card of a particular card type.

(ii) Input, Output Driver and Output Relay cards may comprise two models: discrete (PAC5, PAC6, PAC7) and ASIC (PAC25, PAC26, PAC27). Do not mix these within the same sample of PALCs, as the sample must be homogeneous.

(iii) Input and Output Driver cards are working voltage specific, i.e., 48 Vdc, 125 Vdc or 250 Vdc. Ensure that:

a) Input and Output Driver cards with different working voltages are never mixed in the same crate.

b) Input and Output Driver cards match the crate power supply comprising one of two models:

- VT50-323-10/CB for 48 Vdc station battery
- VT50-321-10/CX for 125 Vdc or 250 Vdc station battery

(iv) More than one version of a particular card model may exist, e.g., PAC25-R2 vs. PAC25-R3. Typically the differences are minor but this must be confirmed before testing continues. If there are insufficient cards of a particular model, leave the designated card slot blank.

(v) I/O Slot 5 is unused and may therefore be used for monitoring the power supply module during the ageing cycles.

B3 PRE-AGEING / POST-AGEING CYCLE TEST SET-UP

B3.1 CPU Slot Test Jig (for power supply testing)

Figure B2 shows the test jig that is inserted into the upper socket in the CPU slot. Only one of these is required that may be implemented as a printed circuit board or vero-board with a harness connected to adjustable load resistors via ammeters.

B3.2 PALC / Omicron Interconnections

Figure B3 shows the PALC / Omicron CMC 256-6 interconnections required to fully test each set of cards. Note the relay board (eight relays) that may be implemented as a printed circuit board or vero-board with suitably terminated wiring harnesses.

B3.3 I/O Slot 5 Test Jig (8-pole, 12 Vdc relay supply)

Figure B4 shows the test jig that is inserted into the upper socket in I/O Slot 5 from which the 12 Vdc supply is derived to switch the eight relays. Only one of these is required that may be implemented as a printed circuit board or vero-board.

B3.4 CPU EPROM (sub module) – PAC4

Figure B5 shows the ladder diagram that must be programmed into a CPU EPROM sub module (PAC4). Note that this PAC4 must not be from the test batch, i.e., is not to be subjected to thermal cycling.

B3.5 Omicron Binary Output and Voltage Output profiles

Figure B6 and B7 show the Binary Output and Voltage Output profiles required to be programmed into the Omicron CMC 256-6.

B4 AGEING CYCLE SET-UP

B4.1 Data Acquisition (Temperature monitoring)

A temperature data acquisition system with sufficient accuracy is required to demonstrate that the thermal walk-in chamber temperature is maintained at 70 ± 2 °C. The sensor must be placed at a representative point that is within 15 cm of the floor, at least 15 cm from the nearest PALC and not in line with, or adjacent to, any radiant heat source or directed air flow.

B4.2 I/O Slot 5 Test Jig (Power supply monitoring)

Figure B8 shows the test jig that is inserted into the upper socket in I/O Slot 5 to monitor crate power supply during an ageing cycle. Each crate will require one of these that may be implemented as a printed circuit board or vero-board with a 5 V relay and harnesses that connect to the previous and next PALC. A lengthy harness from the last PALC leads through the chamber port and may be connected to a supply, suitable resistor and LED, which illuminates when a PALC Power Supply Module fails.

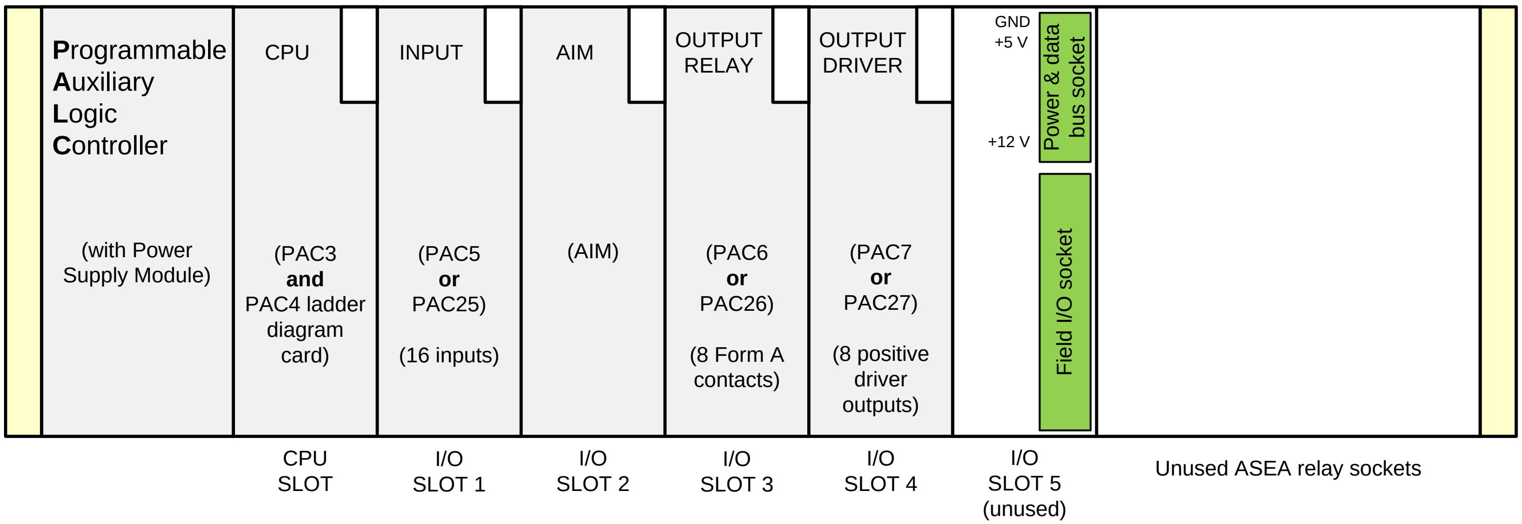


Figure B1 – PALC configuration

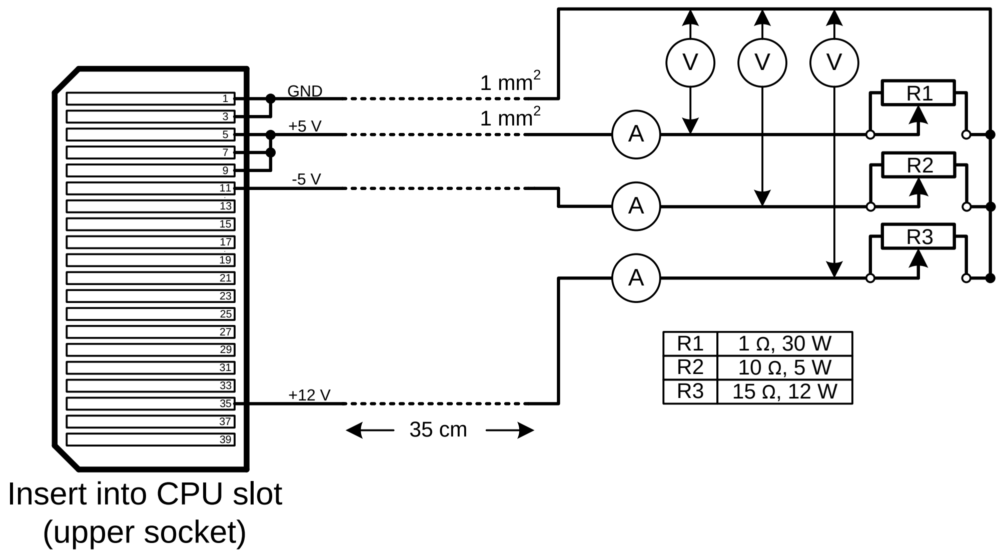


Figure B2 – CPU slot test jig

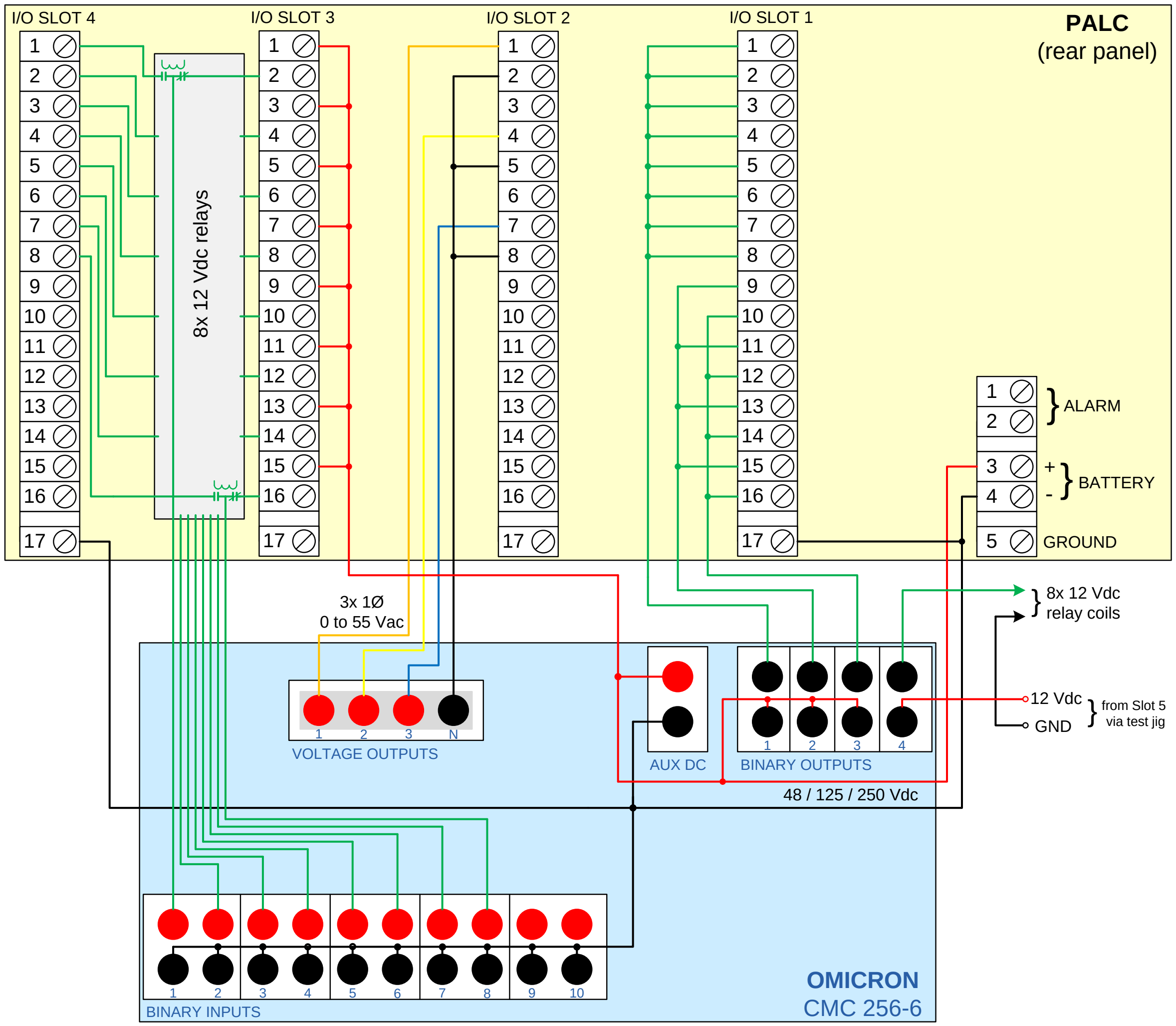


Figure B3 – PALC / Omicron CMC 256-6 interconnections

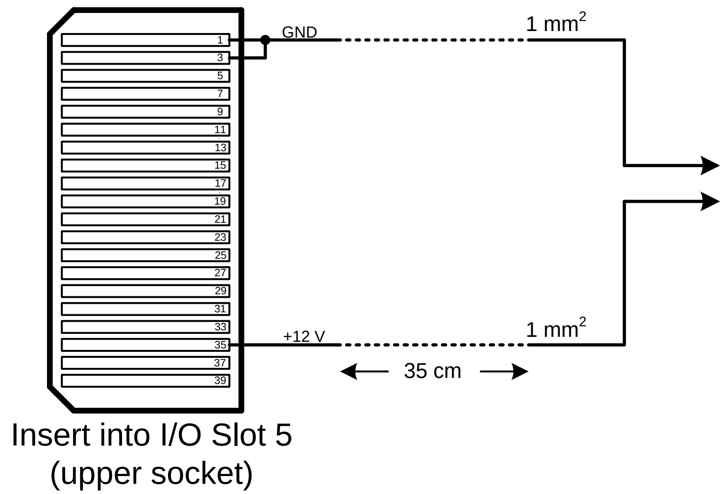


Figure B4 – I/O Slot 5 test jig (8-pole, 12 Vdc relay supply)

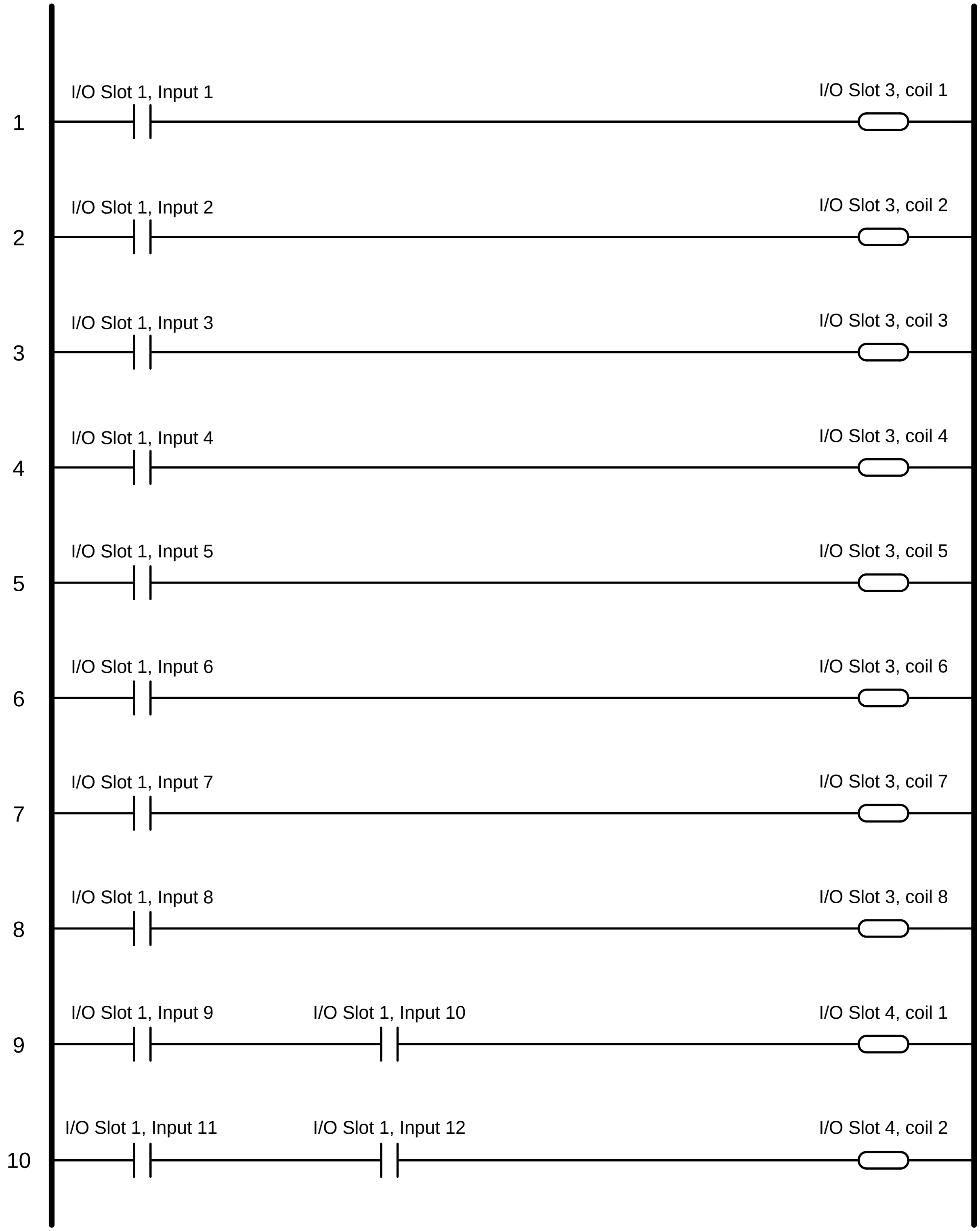


Figure B5 – Test ladder diagram

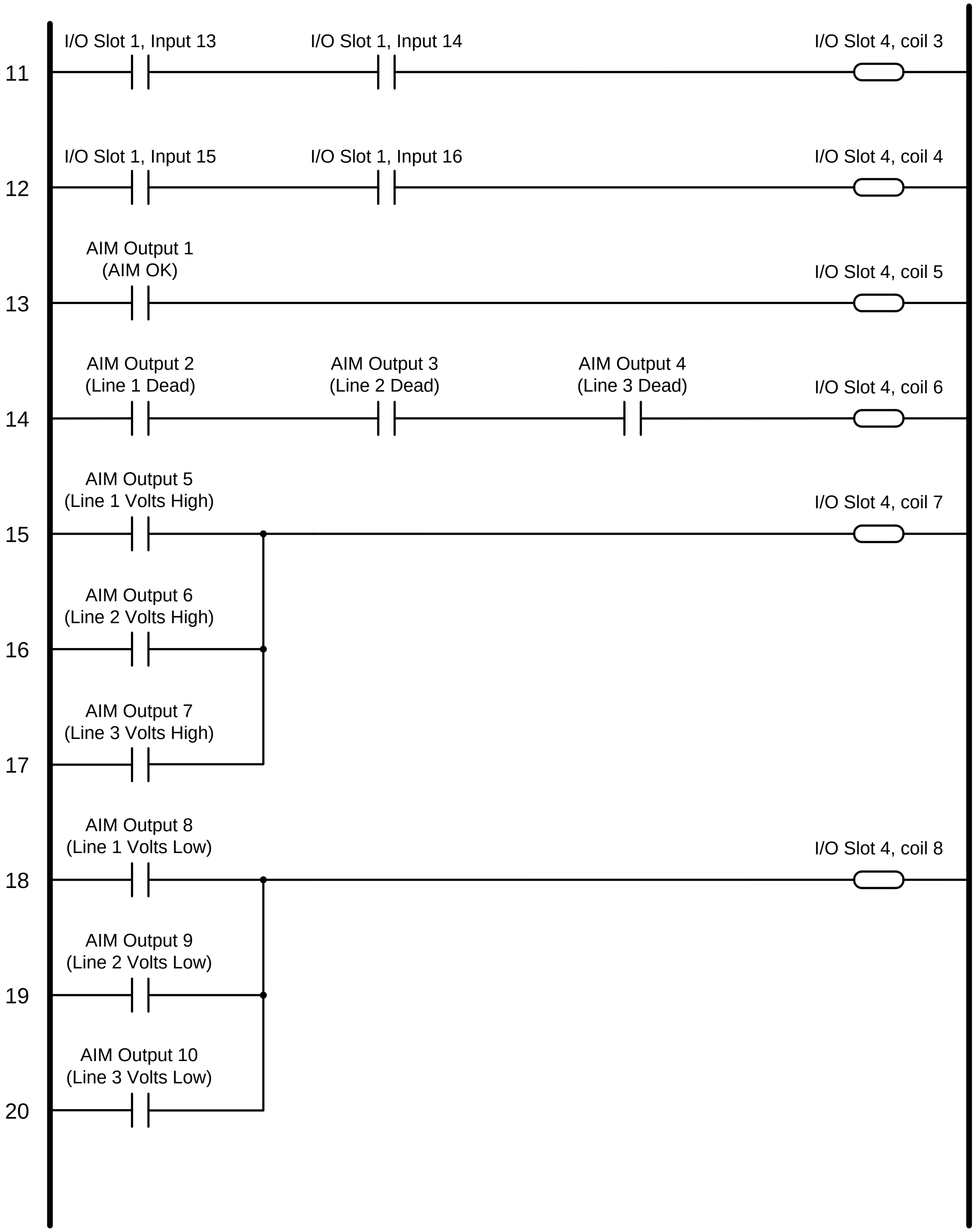
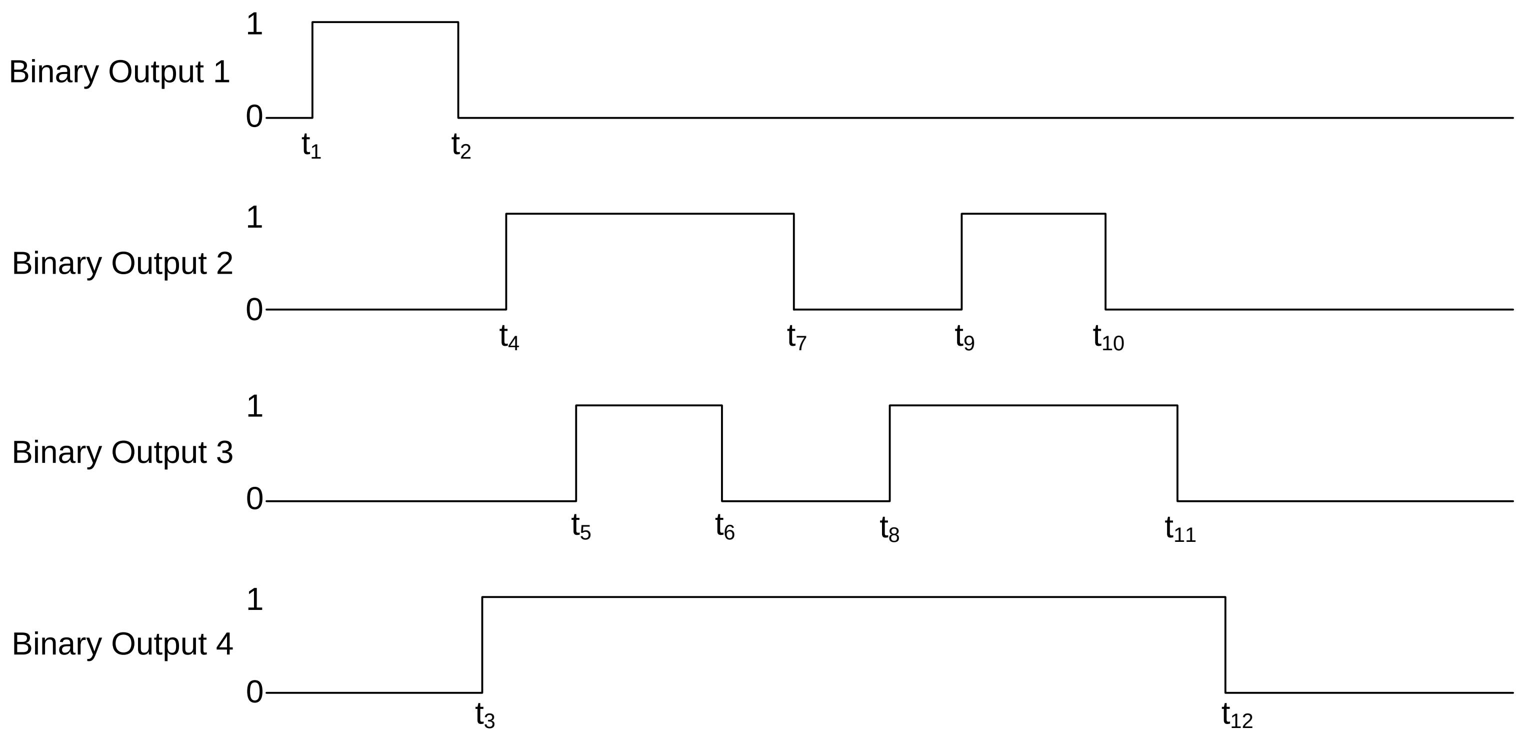


Figure B5 – Test ladder diagram (continued)



t1 < t2 < t3 < t4 < t5 < t6 < t7 < t8 < t9 < t10 < t11 < t12

Figure B6 – Omicron CMC 256-6 Binary Output profiles

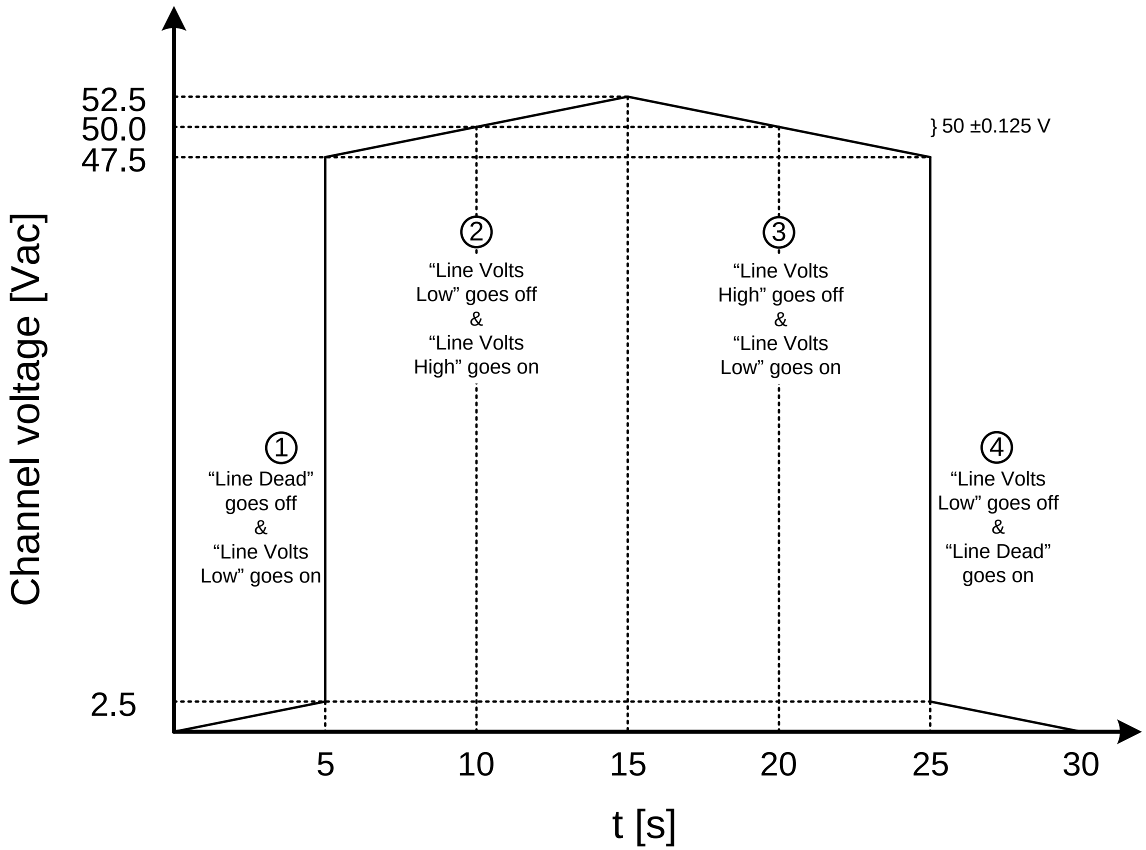


Figure B7 – Omicron CMC 256-6 Voltage Output profile (per channel)

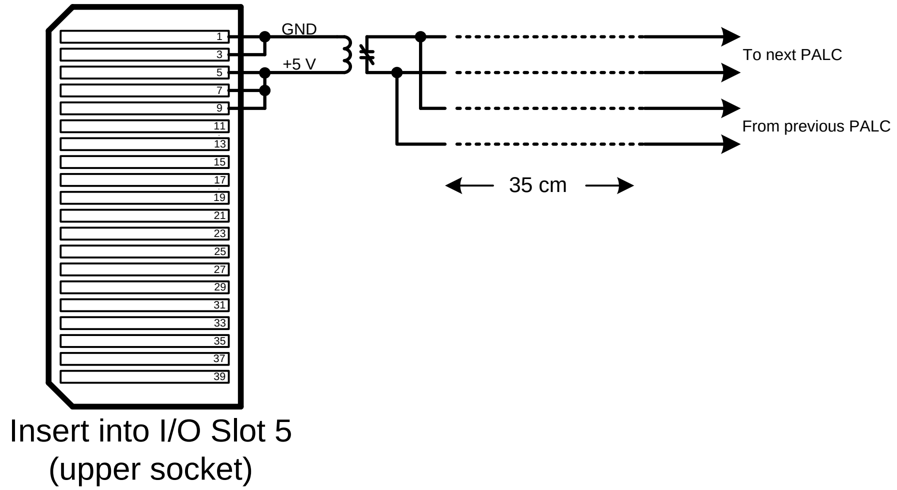


Figure B8 – I/O Slot 5 test jig (power supply monitoring)

16 APPENDIX C: TEST BATCH LABELLING & VISUAL INSPECTION

Table C1 - Complete crates

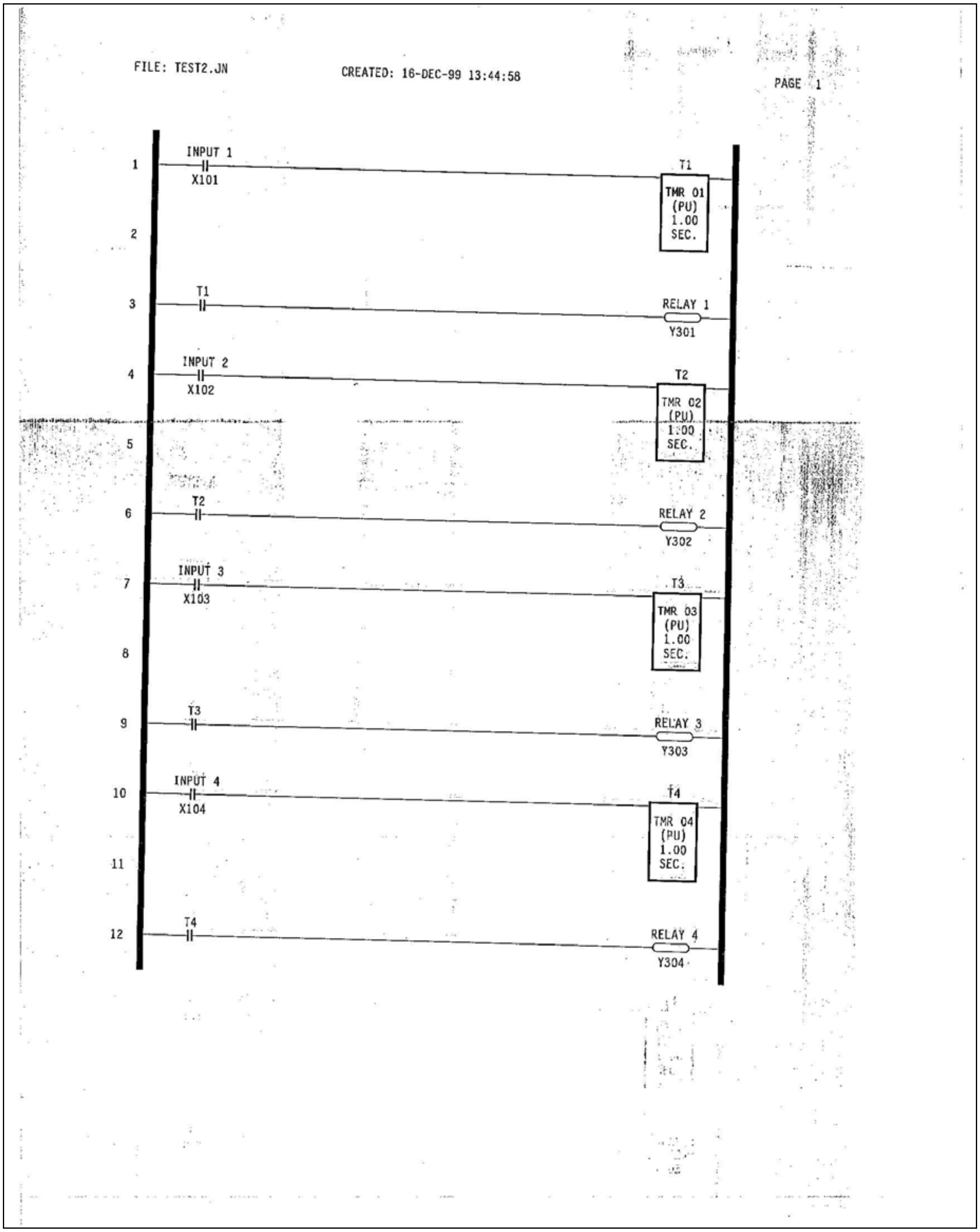
CRATE	SLOT	COMPONENT/CARD/MODULE	TYPE	SERIAL NO.	COMMENTS	Kinectrics label
1	-	Crate (with Power Supply Module)	-	89136		K-418047-250V-PSM-01
	1	CPU	PAC3-R2	3243	bottom of faceplate bent	K-418047-CPU-01
		with daughter board	PAC4	4307		K-418047-CPUE-01
	2	Input	PAC25-R2	5142	overheating on PCB around three resistor pairs	K-418047-250V-I25-01
	3	AIM	AIM-R2	A0349	defective push-to-make switch	K-418047-AIM-01
	4	Blank	PAC9	9650		K-418047-B-01
	5	Output Relay	PAC6-R3	6136	defective DPDT switch	K-418047-OR6-01
	6	Output Driver	PAC7-R2	7294		K-418047-250V-OD7-01
2	-	Crate (with Power Supply Module)	-	89104	missing plate (between CPU and I/O cards)	K-418047-250V-PSM-02
	1	CPU	PAC3-R2	3231	bottom of faceplate bent	K-418047-CPU-02
		with daughter board	PAC4	4301		K-418047-CPUE-02
	2	Input	PAC25-R2	5138	overheating on PCB around three resistor pairs	K-418047-250V-I25-02
	3	AIM	AIM-R2	A004	defective push-to-make switch	K-418047-AIM-02
	4	Blank	PAC9	9706		K-418047-B-02
	5	Output Relay	PAC6-R3	6181	defective DPDT switch	K-418047-OR6-02
	6	Output Driver	PAC7-R2	7142		K-418047-250V-OD7-02
3	-	Crate (with Power Supply Module)	-	91013	missing 8 single-seat ASEA relay socket	K-418047-125V-PSM-01
	1	CPU	PAC3-R2	3382		K-418047-CPU-03
		with daughter board	PAC4	4363		K-418047-CPUE-03
	2	Input	PAC25-R3	5321		K-418047-125V-I25-01
	3	AIM	AIM-R2	A0151		K-418047-AIM-03
	4	Blank	PAC9	9955		K-418047-B-03
	5	Output Driver	PAC27-R2	1516	slightly damaged edge connector	K-418047-125V-OD27-01
	6	Blank	PAC9	9966		K-418047-B-04
4	-	Crate (with Power Supply Module)	-	91025		K-418047-125V-PSM-02
	1	CPU	PAC3-R2	3305		K-418047-CPU-04
		with daughter board	PAC4	4446		K-418047-CPUE-04
	2	Input	PAC25-R3	5339		K-418047-125V-I25-02
	3	Blank	PAC9	9907		K-418047-B-05
	4	Blank	PAC9	9906		K-418047-B-06
	5	Blank	PAC9	9898		K-418047-B-07
	6	Output Driver	PAC7-R2	7330		K-418047-125V-OD7-01
5	-	Crate (with Power Supply Module)	-	91192	5 relays in ASEA sockets	K-418047-125V-PSM-03
	1	CPU	PAC3-R4	3530	green coating peeling off in 2 places	K-418047-CPU-05
		with daughter board	PAC4	4074		K-418047-CPUE-05
	2	Input	PAC25-R3	5555		K-418047-125V-I25-03
	3	AIM	AIM-R2	A0190		K-418047-AIM-04
	4	Blank	PAC9	9977		K-418047-B-08
	5	Blank	PAC9	9836		K-418047-B-09
	6	Output Driver	PAC27-R2	7420		K-418047-125V-OD27-02
6	-	Crate (with Power Supply Module)	-	91176	5 relays in ASEA sockets	K-418047-125V-PSM-04
	1	CPU	PAC3-R4	3570		K-418047-CPU-06
		with daughter board	PAC4	4355		K-418047-CPUE-06
	2	Input	PAC25-R3	5553		K-418047-125V-I25-04
	3	AIM	AIM-R2	A0285		K-418047-AIM-05
	4	Blank	PAC9	9944		K-418047-B-10
	5	Blank	PAC9	9946		K-418047-B-11
	6	Output Driver	PAC27-R2	7429		K-418047-125V-OD27-03
7	-	Crate (with Power Supply Module)	-	91003		K-418047-125V-PSM-05
	1	CPU	PAC3-R2	3308		K-418047-CPU-07
		with daughter board	PAC4	4540		K-418047-CPUE-07
	2	Input	PAC25-R3	5322		K-418047-125V-I25-05
	3	AIM	AIM-R2	A0192		K-418047-AIM-06
	4	Blank	PAC9	9915		K-418047-B-12
	5	Blank	PAC9	9905		K-418047-B-13
	6	Output Driver	PAC27-R2	7320		K-418047-125V-OD27-04
8	-	Crate (with Power Supply Module)	-	91160	missing plate (between CPU and I/O cards); 5 relays in ASEA sockets	K-418047-125V-PSM-06
	1	CPU	PAC3-R4	3547	green coating peeling off in 2 places	K-418047-CPU-08
		with daughter board	PAC4	4333		K-418047-CPUE-08
	2	AIM	AIM-R2	A0230		K-418047-AIM-07
	3	Blank	PAC9	9939		K-418047-B-14
	4	Output Relay	PAC6-R3	6216		K-418047-OR6-03
	5	Output Relay	PAC6-R3	6107		K-418047-OR6-04
	6	Output Driver	PAC27-R2	7556		K-418047-125V-OD27-05

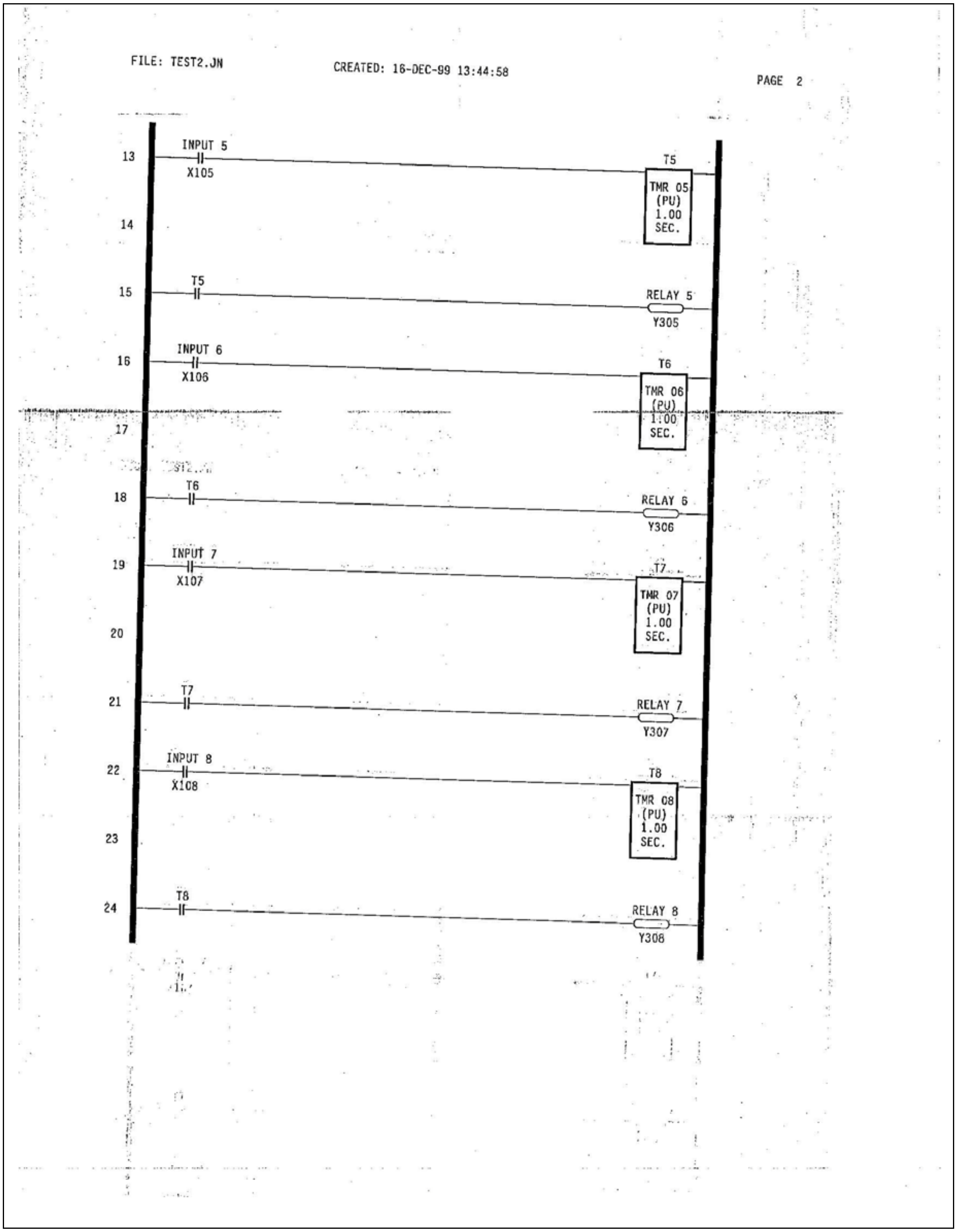
CRATE	SLOT	COMPONENT/CARD/MODULE	TYPE	SERIAL NO.	COMMENTS	Kinectrics label
9	-	Crate (with Power Supply Module)	-	91162	3 relays in ASEA socket	K-418047-125V-PSM-07
	1	CPU	PAC3-R4	3420	bottom of faceplate bent	K-418047-CPU-09
		with daughter board	PAC4	4113		K-418047-CPUE-09
	2	Input	PAC25-R3	5416		K-418047-125V-I25-06
	3	Blank	PAC9	91004		K-418047-B-15
	4	Blank	PAC9	91006		K-418047-B-16
	5	Blank	PAC9	91007		K-418047-B-17
	6	Output Driver	PAC27-R2	7303		K-418047-125V-OD27-06
10	-	Crate (with Power Supply Module)	-	91175	1 relay in ASEA socket	K-418047-125V-PSM-08
	1	CPU	PAC3-R4	3546		K-418047-CPU-10
		with daughter board	PAC4	4386		K-418047-CPUE-10
	2	Input	PAC25-R3	5509		K-418047-125V-I25-07
	3	AIM	AIM-R2	A0204		K-418047-AIM-08
	4	Blank	PAC9	91142		K-418047-B-18
	5	Output Driver	PAC27-R2	7477		K-418047-125V-OD27-07
	6	Blank	PAC9	9898		K-418047-B-19
11	-	Crate (with Power Supply Module)	-	89226	1 relay in ASEA socket	K-418047-125V-PSM-09
	1	CPU	PAC3-R4	3565	bottom of faceplate bent	K-418047-CPU-11
		with daughter board	PAC4	4326		K-418047-CPUE-11
	2	Input	PAC25-R3	5519		K-418047-125V-I25-08
	3	AIM	AIM-R2	A0112		K-418047-AIM-09
	4	Blank	PAC9	9797		K-418047-B-20
	5	Output Driver	PAC27-R2	7494		K-418047-125V-OD27-08
	6	Blank	PAC9	9938		K-418047-B-21
12	-	Crate (with Power Supply Module)	-	91119	3 relays in ASEA socket	K-418047-125V-PSM-10
	1	CPU	PAC3-R4	3446	bottom of faceplate bent	K-418047-CPU-12
		with daughter board	PAC4	4277		K-418047-CPUE-12
	2	Input	PAC25-R3	5424		K-418047-125V-I25-09
	3	Blank	PAC9	9897		K-418047-B-22
	4	Blank	PAC9	9900		K-418047-B-23
	5	Blank	PAC9	91140		K-418047-B-24
	6	Output Driver	PAC27-R2	7394		K-418047-125V-OD27-09
13	-	Crate (with Power Supply Module)	-	89300	3 relays in ASEA sockets	K-418047-125V-PSM-11
	1	CPU	PAC3-R4	3568		K-418047-CPU-13
		with daughter board	PAC4	4098	missing 2x EPROM masks	K-418047-CPUE-13
	2	Input	PAC25-R3	5561		K-418047-125V-I25-10
	3	Blank	PAC9	91137		K-418047-B-25
	4	Blank	PAC9	91121		K-418047-B-26
	5	Blank	PAC9	9771		K-418047-B-27
	6	Output Driver	PAC27-R2	7391		K-418047-125V-OD27-10
14	-	Crate (with Power Supply Module)	-	91167	3 relays in ASEA socket	K-418047-125V-PSM-12
	1	CPU	PAC3-R4	3441	faceplate slightly bent	K-418047-CPU-14
		with daughter board	PAC4	4451		K-418047-CPUE-14
	2	Input	PAC25-R3	5435		K-418047-125V-I25-11
	3	Blank	PAC9	9950		K-418047-B-28
	4	Blank	PAC9	9951		K-418047-B-29
	5	Blank	PAC9	9952		K-418047-B-30
	6	Output Driver	PAC27-R2	7476		K-418047-125V-OD27-11
15	-	Crate (with Power Supply Module)	-	89239	4 relays in ASEA socket	K-418047-125V-PSM-13
	1	CPU	PAC3-R4	3478	green coating peeling off in 2 places	K-418047-CPU-15
		with daughter board	PAC4	4724		K-418047-CPUE-15
	2	Input	PAC25-R3	5542		K-418047-125V-I25-12
	3	Blank	PAC9	91491		K-418047-B-31
	4	Blank	PAC9	91124		K-418047-B-32
	5	Blank	PAC9	91041		K-418047-B-33
	6	Output Driver	PAC27-R2	7490		K-418047-125V-OD27-12
16	-	Crate (with Power Supply Module)	-	91131	3 relays in ASEA sockets	K-418047-125V-PSM-14
	1	CPU	PAC3-R4	3449		K-418047-CPU-16
		with daughter board	PAC4	4575		K-418047-CPUE-16
	2	Input	PAC25-R3	5350		K-418047-125V-I25-13
	3	Blank	PAC9	9815		K-418047-B-34
	4	Blank	PAC9	9814		K-418047-B-35
	5	Blank	PAC9	9813		K-418047-B-36
	6	Output Driver	PAC27-R2	7459		K-418047-125V-OD27-13

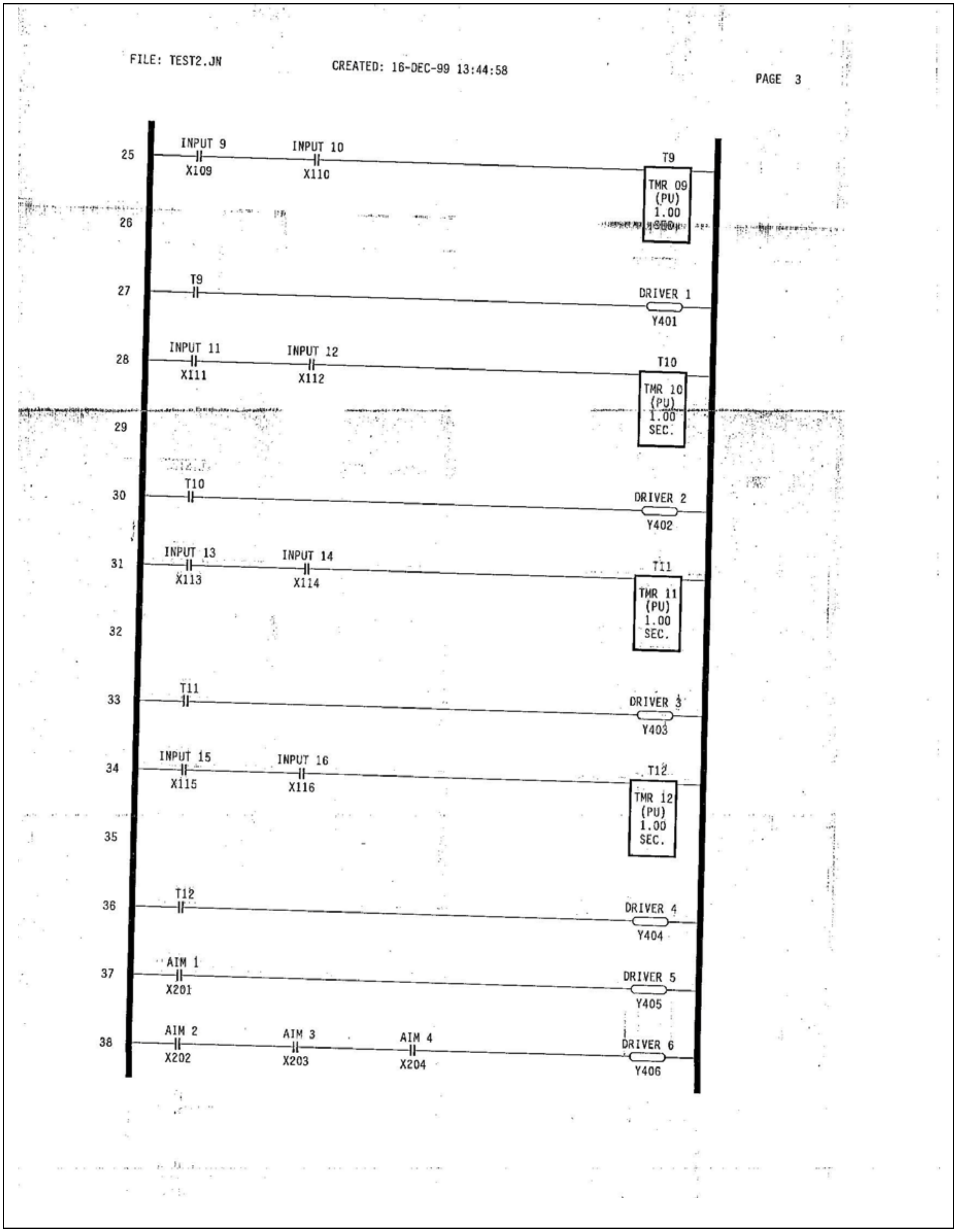
Table C2 - Supplementary cards

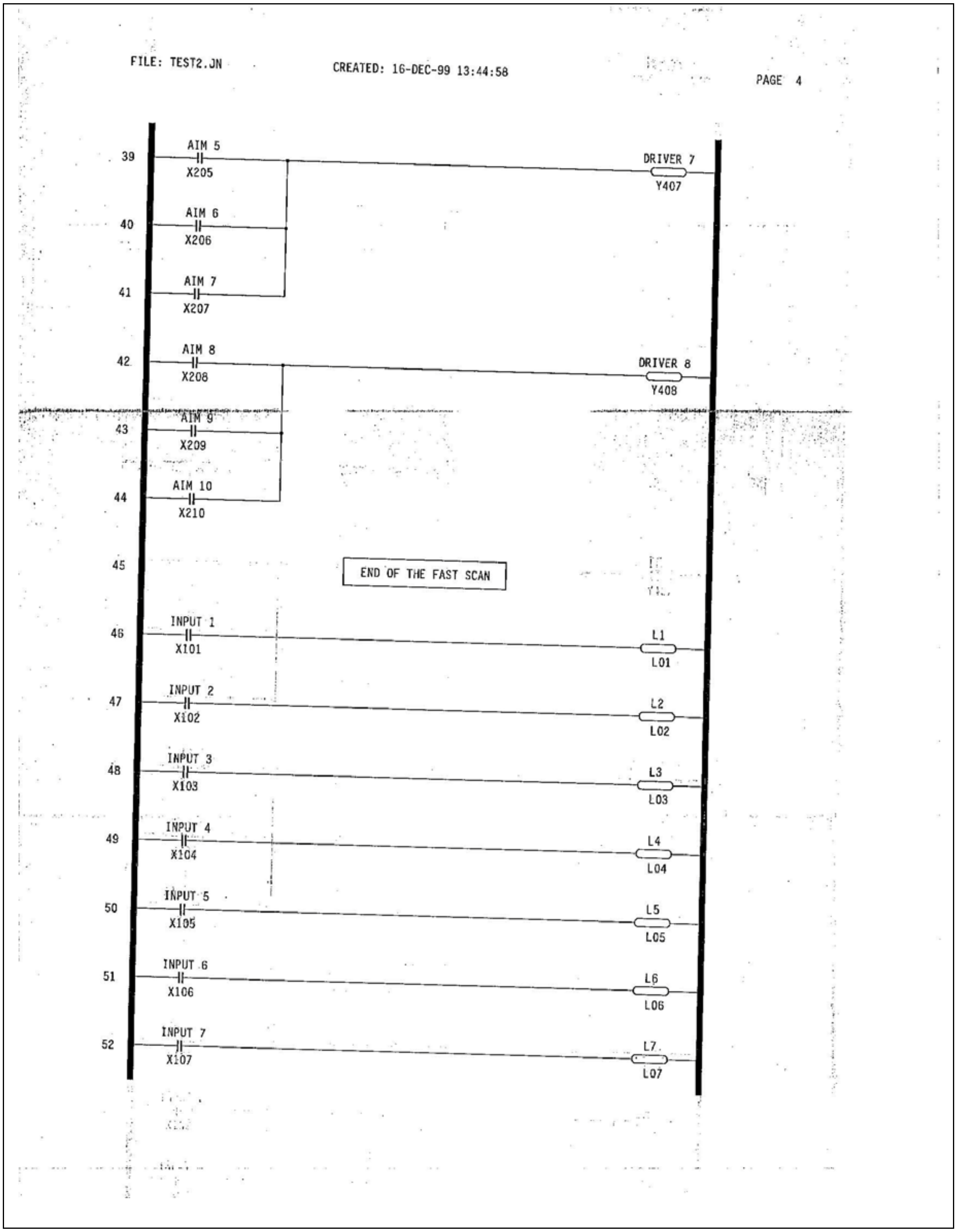
COMPONENT/CARD/MODULE	TYPE	SERIAL NO.	COMMENTS	Kinectrics label
AIM	AIM-R2	A0363	Broken button on push-to-make switch	K-418047-AIM-10
AIM	AIM-R2	A0260	EEPROM removed and re-inserted incorrectly/improperly	K-418047-AIM-11
AIM	AIM-R2	A0255		K-418047-AIM-12
Output Relay	PAC6-R3	6208		K-418047-OR6-05
Output Relay	PAC6-R3	6200		K-418047-OR6-06
Output Relay	PAC6-R3	6141		K-418047-OR6-07

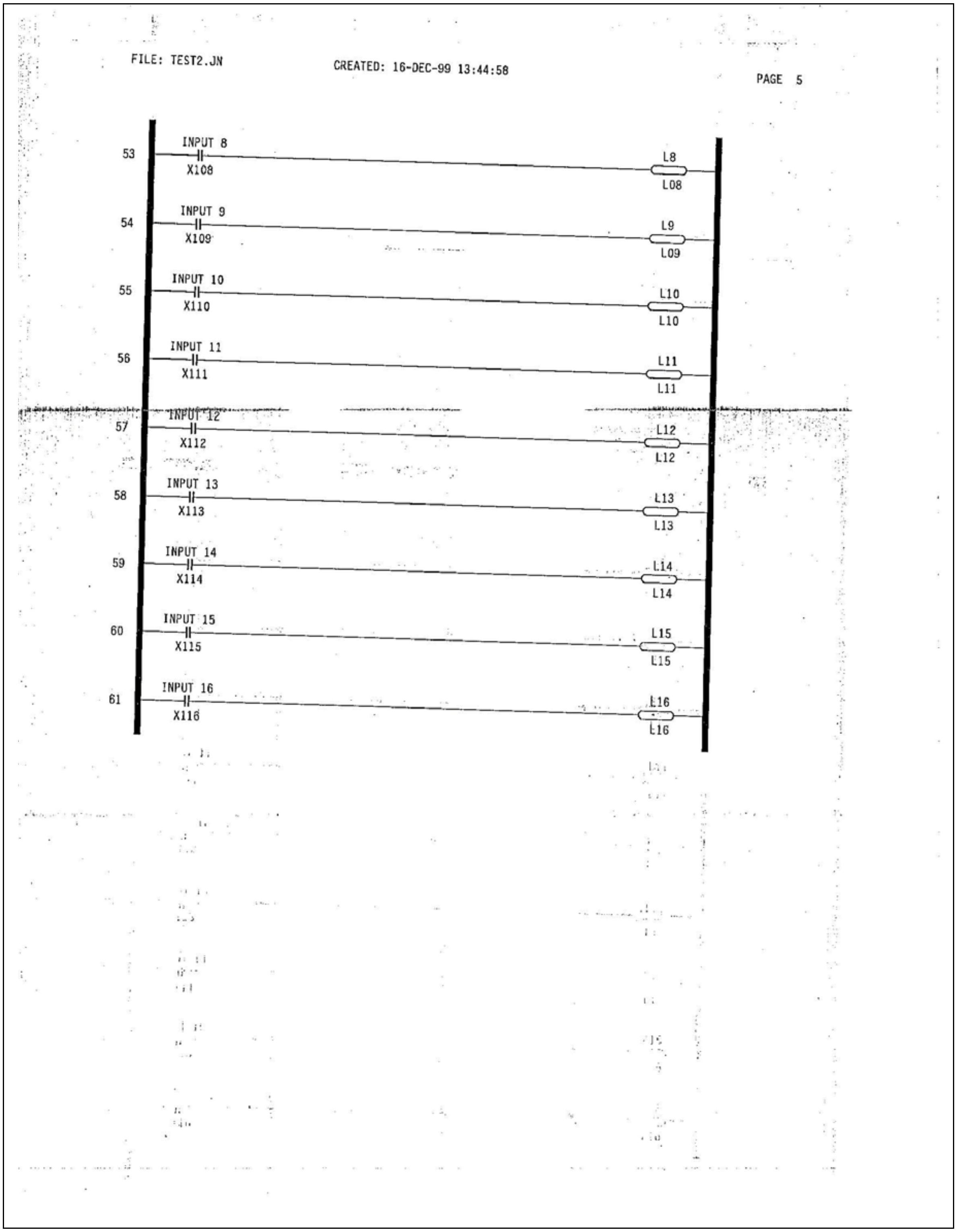
17 APPENDIX D: TEST-SPECIFIC LADDER DIAGRAM




FILE: TEST2.JN
CREATED: 16-DEC-99 13:44:58
PAGE 2
13
14
15
16
17
18
19
20
21
22
23
24
INPUT 5
X105
T5
TMR 05
(PU)
1.00
SEC.
T5
RELAY 5
Y305
INPUT 6
X106
T6
TMR 06
(PU)
1.00
SEC.
T6
RELAY 6
Y306
INPUT 7
X107
T7
TMR 07
(PU)
1.00
SEC.
T7
RELAY 7
Y307
INPUT 8
X108
T8
TMR 08
(PU)
1.00
SEC.
T8
RELAY 8
Y308


FILE: TEST2.JN
CREATED: 16-DEC-99 13:44:58
PAGE 3
25
INPUT 9
X109
INPUT 10
X110
T9
TMR 09
(PU)
1.00
SEC.
26
27
T9
DRIVER 1
Y401
28
INPUT 11
X111
INPUT 12
X112
T10
TMR 10
(PU)
1.00
SEC.
29
30
T10
DRIVER 2
Y402
31
INPUT 13
X113
INPUT 14
X114
T11
TMR 11
(PU)
1.00
SEC.
32
33
T11
DRIVER 3
Y403
34
INPUT 15
X115
INPUT 16
X116
T12
TMR 12
(PU)
1.00
SEC.
35
36
T12
DRIVER 4
Y404
37
AIM 1
X201
DRIVER 5
Y405
38
AIM 2
X202
AIM 3
X203
AIM 4
X204
DRIVER 6
Y406


FILE: TEST2.JN
CREATED: 16-DEC-99 13:44:58
PAGE 4
39
AIM 5
X205
DRIVER 7
Y407
40
AIM 6
X206
41
AIM 7
X207
42
AIM 8
X208
DRIVER 8
Y408
43
AIM 9
X209
44
AIM 10
X210
45
END OF THE FAST SCAN
46
INPUT 1
X101
L1
L01
47
INPUT 2
X102
L2
L02
48
INPUT 3
X103
L3
L03
49
INPUT 4
X104
L4
L04
50
INPUT 5
X105
L5
L05
51
INPUT 6
X106
L6
L06
52
INPUT 7
X107
L7
L07


FILE: TEST2.JN
CREATED: 16-DEC-99 13:44:58
PAGE 5
53
INPUT 8
X108
L8
L08
54
INPUT 9
X109
L9
L09
55
INPUT 10
X110
L10
L10
56
INPUT 11
X111
L11
L11
57
INPUT 12
X112
L12
L12
58
INPUT 13
X113
L13
L13
59
INPUT 14
X114
L14
L14
60
INPUT 15
X115
L15
L15
61
INPUT 16
X116
L16
L16

FILE: TEST2.JN CREATED: 16-DEC-99 13:44:58 PAGE 1

Card usage: IIRD-

EXTERNAL LABELS

Slot: 1 Type: Input

I/O no.	Label	References	
X101	INPUT 1	1	46
X102	INPUT 2	4	47
X103	INPUT 3	7	48
X104	INPUT 4	10	49
X105	INPUT 5	13	50
X106	INPUT 6	16	51
X107	INPUT 7	19	52
X108	INPUT 8	22	53
X109	INPUT 9	25	54
X110	INPUT 10	25	55
X111	INPUT 11	28	56
X112	INPUT 12	28	57
X113	INPUT 13	31	58
X114	INPUT 14	31	59
X115	INPUT 15	34	60
X116	INPUT 16	34	61

Slot: 2 Type: Input

I/O no.	Label	References
X201	AIM 1	37
X202	AIM 2	38
X203	AIM 3	38
X204	AIM 4	38
X205	AIM 5	39
X206	AIM 6	40
X207	AIM 7	41
X208	AIM 8	42
X209	AIM 9	43
X210	AIM 10	44
X211	[illegible]	
X212	[illegible]	
X213	[illegible]	
X214	[illegible]	
X215	[illegible]	
X216	[illegible]	

FILE: TEST2.JN CREATED: 16-DEC-99 13:44:58 PAGE 2

Slot: 3 Type: Relay

I/O no.	Label	References
Y301	RELAY 1	3*
Y302	RELAY 2	6*
Y303	RELAY 3	9*
Y304	RELAY 4	12*
Y305	RELAY 5	15*
Y306	RELAY 6	18*
Y307	RELAY 7	21*
Y308	RELAY 8	24*

("*" = Controlled device)

Slot: 4 Type: Driver

I/O no.	Label	References
Y401	DRIVER 1	27*
Y402	DRIVER 2	30*
Y403	DRIVER 3	33*
Y404	DRIVER 4	36*
Y405	DRIVER 5	37*
Y406	DRIVER 6	38*
Y407	DRIVER 7	39*
Y408	DRIVER 8	42*

("*" = Controlled device)

OPERATION INDICATORS

No.	Label	References
L01	L1	46*
L02	L2	47*
L03	L3	48*
L04	L4	49*
L05	L5	50*
L06	L6	51*
L07	L7	52*
L08	L8	53*
L09	L9	54*
L10	L10	55*
L11	L11	56*
L12	L12	57*
L13	L13	58*
L14	L14	59*
L15	L15	60*
L16	L16	61*

("*" = Controlled device)

FILE: TEST2.JN CREATED: 16-DEC-99 13:44:58 PAGE 3

(NO INTERNAL SWITCHES USED)

INTERNAL STATUS FLAGS

Label	References
BLOCK	
SPARE FLAG 1	
OUTPUT BLOCK	
I/O CARD FAULT	
CPU FAULT	
WATCHDOG TIME-OUT	
SYSTEM RESTART	
ALL OKAY	

INTERNAL LABELS

Tmr/Cnt	Label	References
TMR 1	T1	1* 3
TMR 10	T10	28* 30
TMR 11	T11	31* 33
TMR 12	T12	34* 36
TMR 2	T2	4* 6
TMR 3	T3	7* 9
TMR 4	T4	10* 12
TMR 5	T5	13* 15
TMR 6	T6	16* 18
TMR 7	T7	19* 21
TMR 8	T8	22* 24
TMR 9	T9	25* 27

("*" = Controlled device)

TIMER SETTINGS

No.	Label	Setting	No.	Label	Setting
1	T1	1.00	2	T2	1.00
3	T3	1.00	4	T4	1.00
5	T5	1.00	6	T6	1.00
7	T7	1.00	8	T8	1.00
9	T9	1.00	10	T10	1.00
11	T11	1.00	12	T12	1.00
13			14		
15			16		

(NO COUNTERS USED)

```
PALC LADDER DIAGRAM COMPILER

FILE: TEST2.JN                         CREATED: 16-DEC-99 13:44:58

SYSTEM:

          61 (of 400) lines used
          12 (of 192) internal labels used
          12 (of 16) timers used
           0 (of 8) counters used
           0 (of 16) Master Control Relays used
           1 (of 10000) bytes of text/comment storage used
        7750 (of 12288) bytes of PALC memory used

 Beginning of ladder code          6328
 Beginning of free memory          7750

Ladder execution time (8 MHz clock)

Fast scan time =     937.5 usec
Slow scan time =     284.0 usec
```

18 APPENDIX E: OMICRON SCREEN-SHOTS

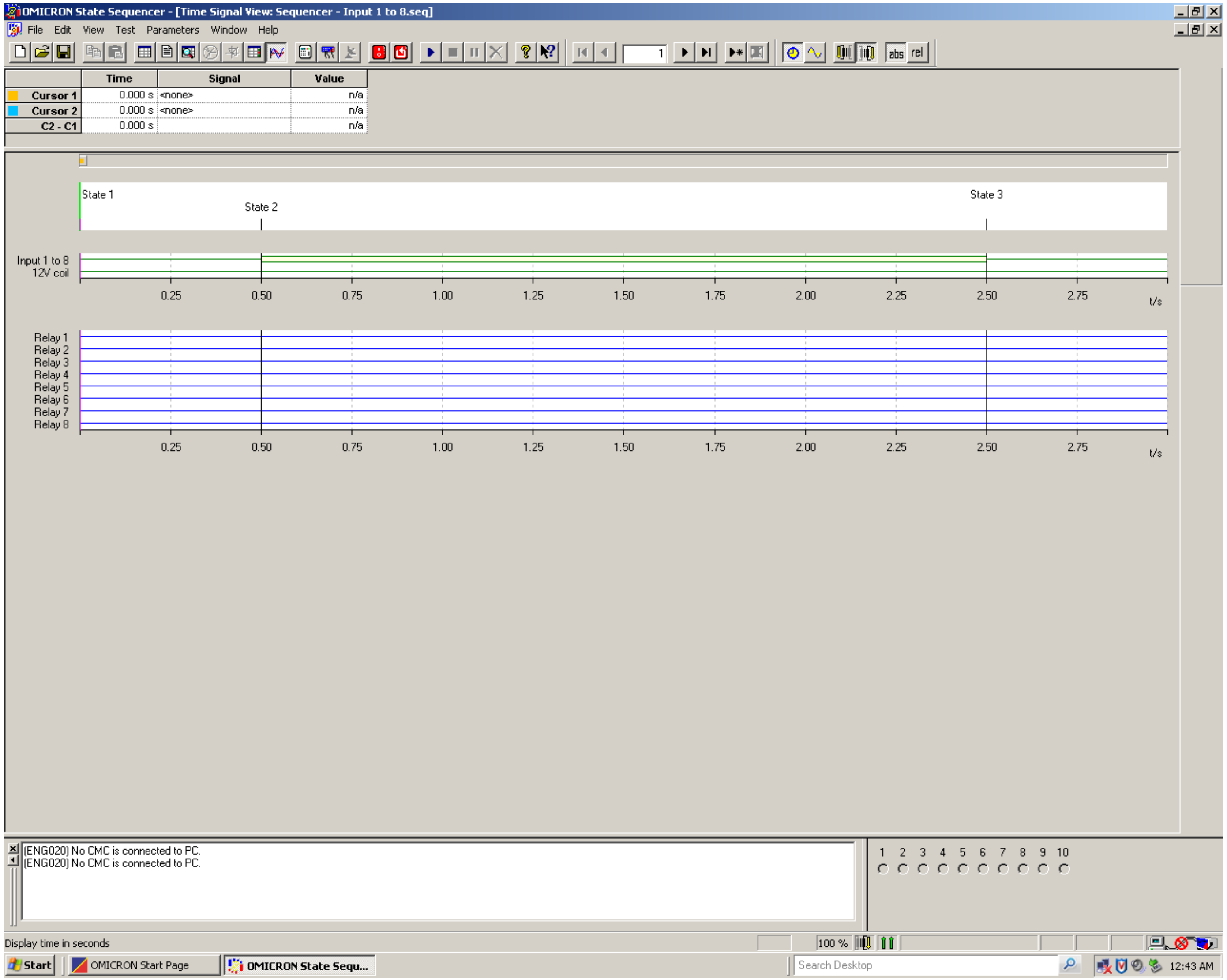


Figure E1 – Omicron State Sequencer (Input 1 to 8.seq) screen shot

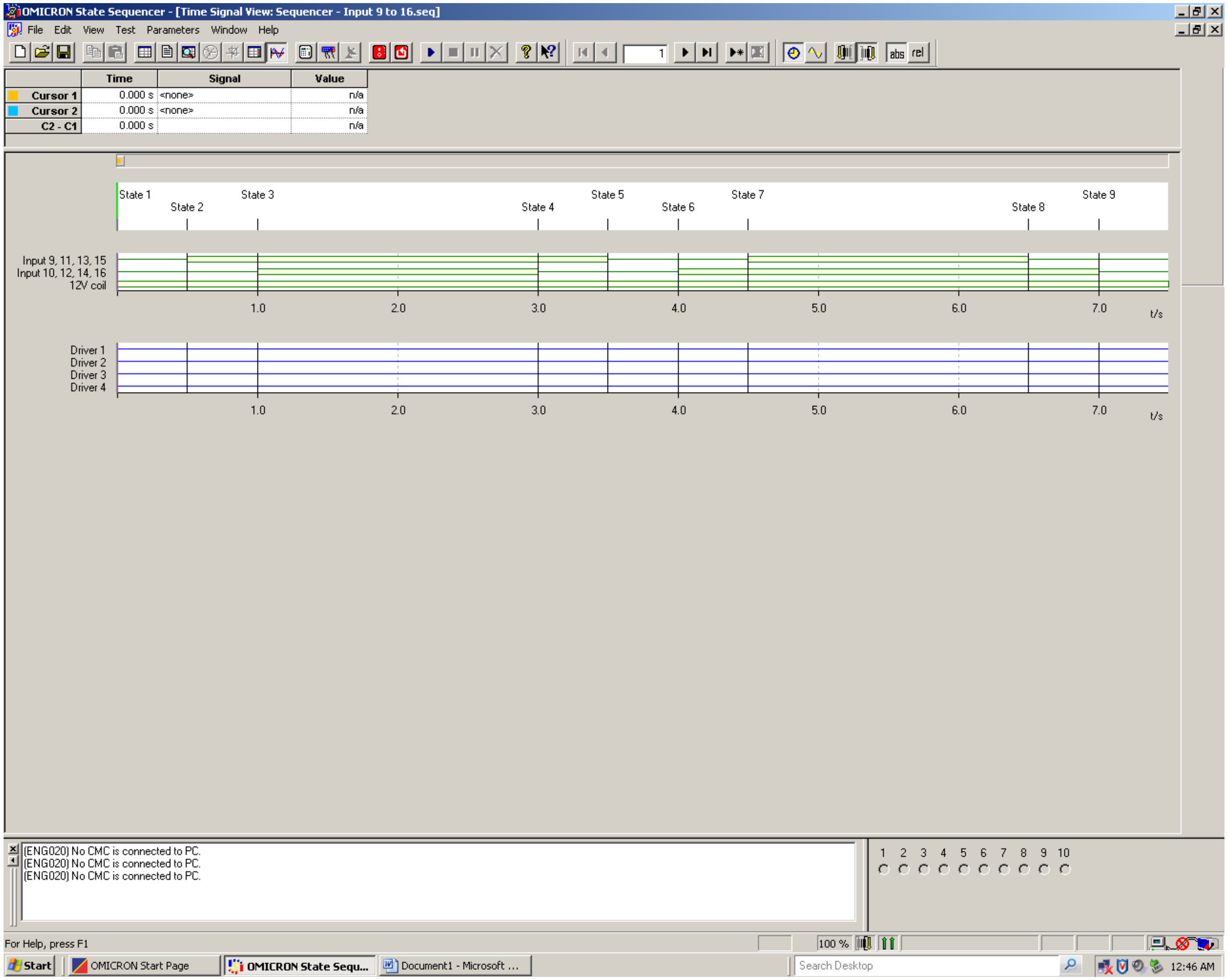


Figure E2 – Omicron State Sequencer (Input 9 to 16.seq) screen shot

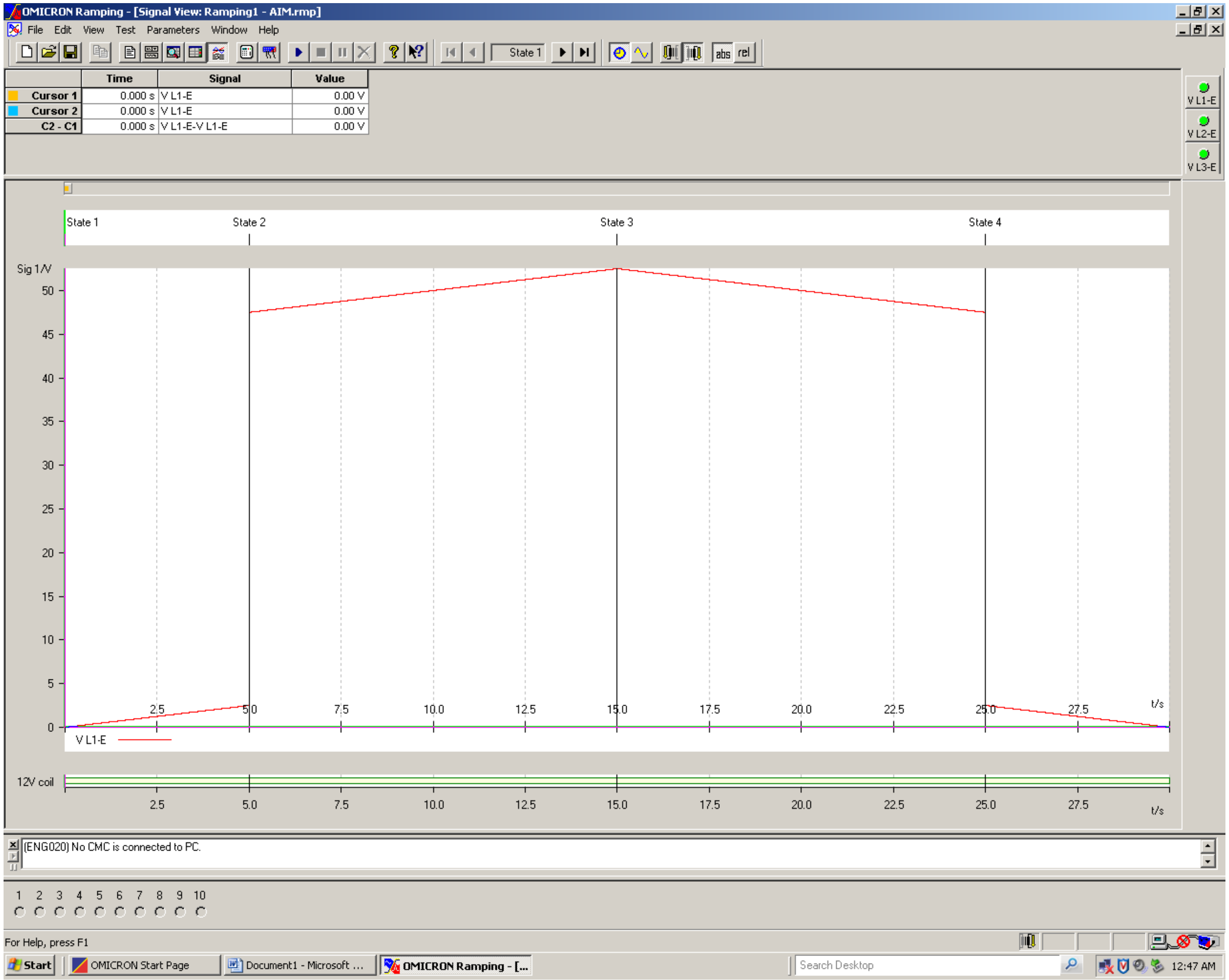


Figure E3 – Omicron Ramping (Ramping1 – AIM.rmp) screen shot

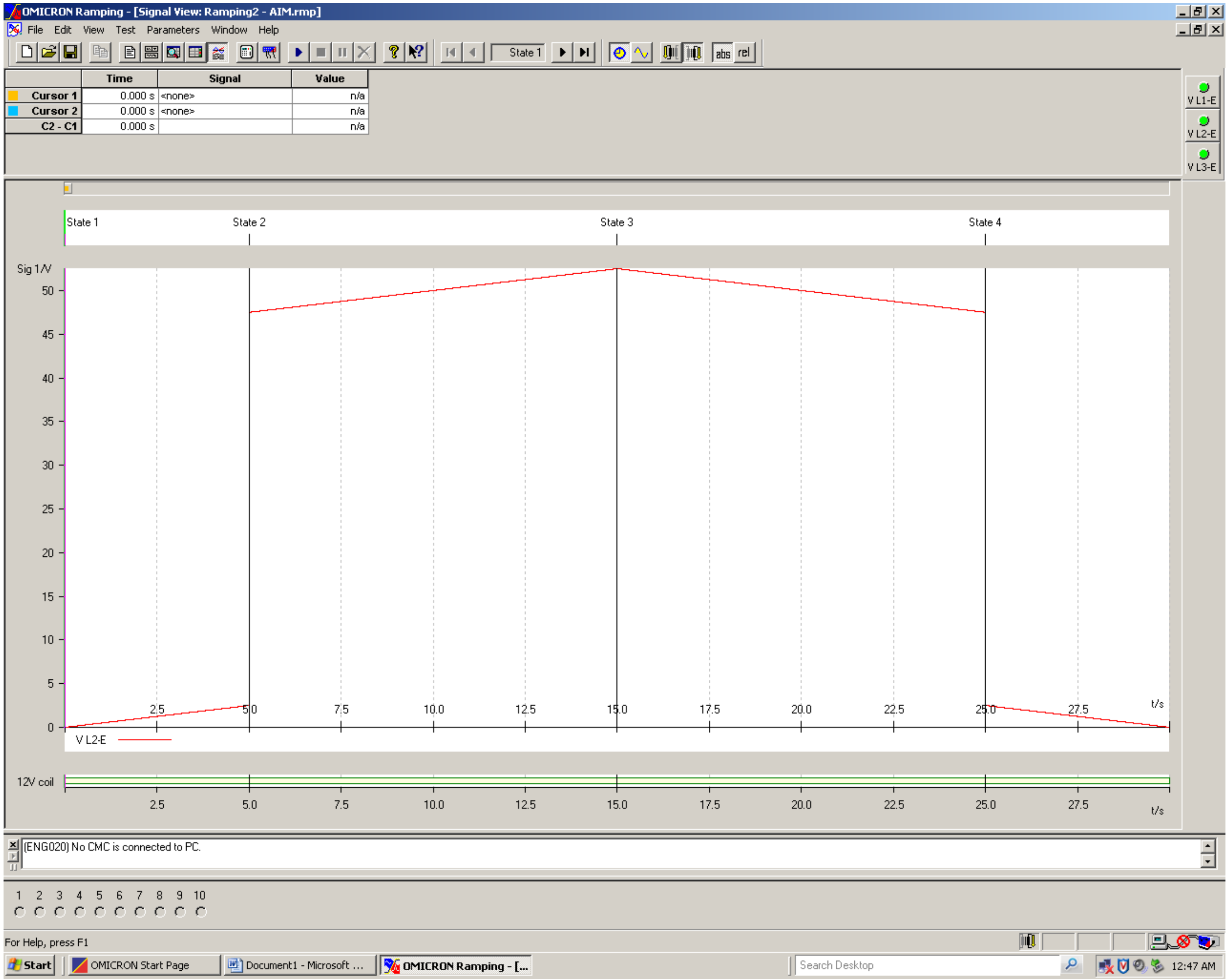


Figure E4 – Omicron Ramping (Ramping2 – AIM.rmp) screen shot

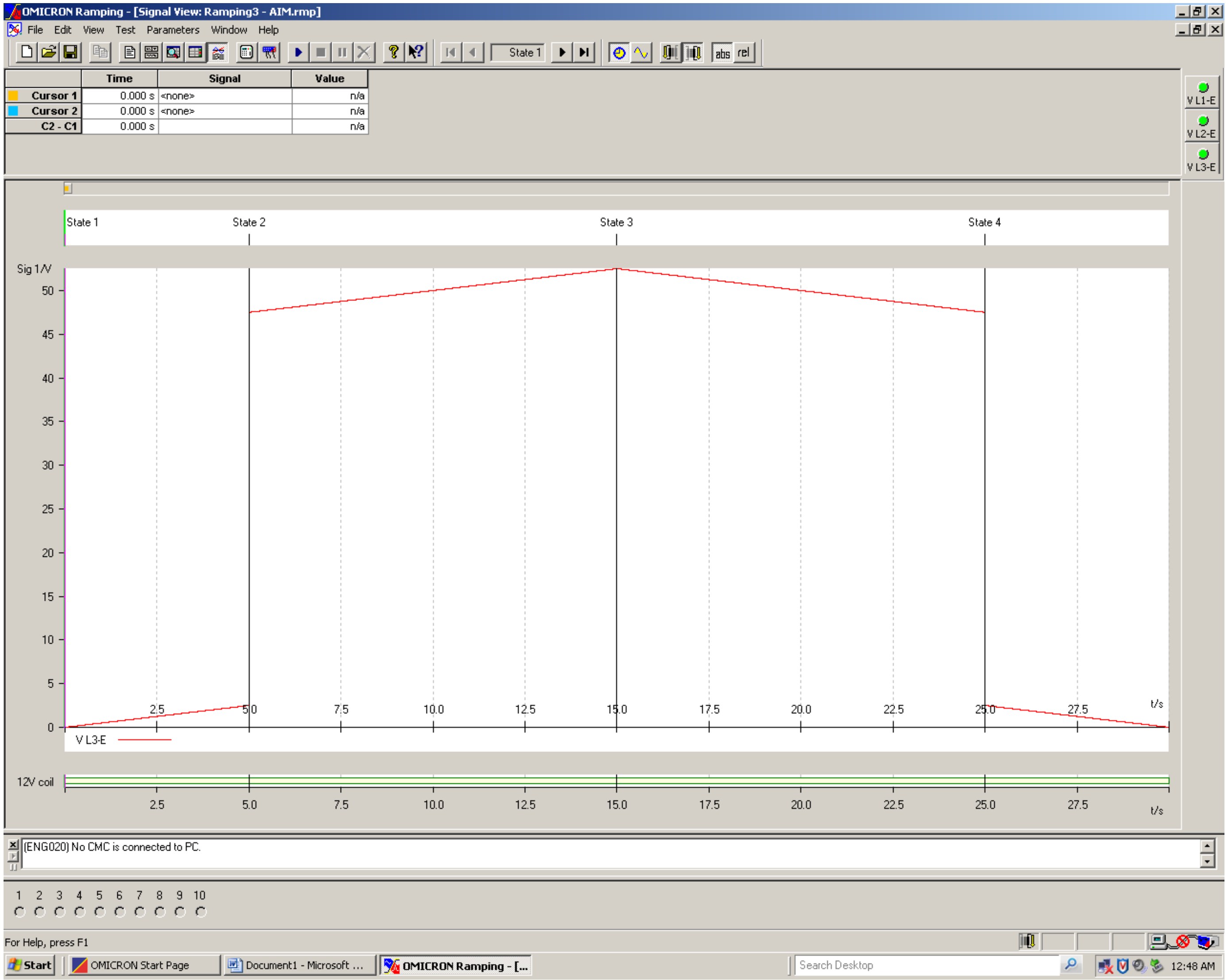


Figure E5 – Omicron Ramping (Ramping3 – AIM.rmp) screen shot

19 DISTRIBUTION

Mr Paul DiFilippo	–	Hydro One
Mr Charles Esendal	–	Hydro One
Mr Arend Koert	–	Kinectrics
Mr Tom Gough	–	Kinectrics
Kinectrics ISO File	–	Kinectrics

Ontario Energy Board (Board Staff) INTERROGATORY #047

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.3.3: Protection and Automation - Asset Assessment Details, Table 7 – Protection Systems Expected Service Life, pg. 24 (PDF 925); Section 2.3.3: Protection and Automation - Asset Assessment Details, Condition, pg. 27

Table 7: Protection Systems Expected Service Life

Protection Technology	*Expected Service Life*
Electromechanical	45 years
Solid State	25 years
Microprocessor	20 years

"Protection system condition is an important indicator of equipment reliability. Condition is primarily based on age and findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, which can alter the performance of the relay. This is primarily a concern with electromechanical systems, but component aging or defects and thermal cycling can also affect solid state and microprocessor based protection systems. Microprocessor based protections are a relatively new technology, detailed condition metrics and indicators are not as well established."

Interrogatory:

a) Please reconcile the claim in Table 7 that electromechanical systems have a significantly longer expected service life than solid state or microprocessor systems with the statement that they are the systems most affected by degradation over time.

b) Given that Microprocessor relays are relatively new technology, are not as affected by time degradation as electromechanical relays, and generally require less operational intervention, how did Hydro One determine the 20 year expected life value?

c) What is the likelihood that these relays may ultimately demonstrate effective service lives equivalent to or longer than electromechanical or solid state relay systems?

Response:

a) Electromechanical relays are of very robust construction based on a simple electromagnetic induction principle. Microprocessor and solid state are digital relays comprised of discrete components using integrated circuit technology. Electromechanical relays are fully analog in nature requiring calibration over time whereas microprocessor is digital in nature and once the analog signal is converted to low energy digital signal, it generally does not require periodic calibration. Please refer to Exhibit B1, Tab 2, Schedule 6, Section 2.3.1 for additional information on protection system technology.

b) The expected service life for microprocessor relays is based on manufacturers' statements of product support, average lifespans for similar devices adopted by peer utilities, further supported by a white paper prepared by an independent technical body which evaluated expected service life of a select group of microprocessor relays. Kinectrics conducted a study in 2012 - IED End of Life Study for Digital Relays (PR-90-028). Please see Attachment 1 of this response. The report suggests that EOL of digital relays is around 15 - 20 years.

c) It is uncertain if microprocessor based relays will demonstrate effective service life equivalent to electromechanical or solid state systems due to the complexity of the integrated circuit design with large amount of discrete components (Please refer to the Kinectrics study in (b) above). However, microprocessor relays can self-monitor and alarm when failures occur and have other features that can benefit the operation of the power system as outlined in Exhibit B1, Tab2, Schedule 6, Page 22.

IED End of Life Study for Digital Relays

Kinectrics Inc. Report No. K-015805-RA-001-R01
Hydro One Report No. PR – 90 – 028 – R0

November 2012

Fan Wang

Senior Engineer / Scientist
Transmission & Distribution Technologies Business
Kinectrics Inc.

LIMITATION OF LIABILITY AND DISCLAIMER

CONTACT/PUBLISHER

This document is the responsibility of the Transmission Projects Development Division, Hydro One Networks Inc. Please contact the Manager with any queries or suggestions.

Strategy
Transmission Projects Development Division
483 Bay Street (TCT15N)
Toronto, Ontario, M5G-2P5
www.HydroOne.com

IED End of Life Study for Digital Relays

Kinectrics Report No.: K-015805-RA-001-R01
Hydro One Report No.: PR-90-028-R0

	Prepared by	**Reviewed by**
Signature		
Name	**Fan Wang**	**Mansour Jalali**
Title	Senior Engineer / Scientist Transmission & Distribution Technologies Kinectrics	Service Line Leader of SAA Transmission & Distribution Technologies Kinectrics
Date	2012-11-08	2012-11-08

	Approved by	**Approved by**	**Approved by**
Signature			
Name	**Harpinder Gill**	**Dave Clarke**	**Paul DiFilippo**
Title	Department Manager of Substation Transmission & Distribution Technologies Kinectrics	General Manager Transmission & Distribution Technologies Kinectrics	Reliability Standards Manager P&C Strategies and Standards Hydro One
Date	Nov. 9, 2012	Nov 9, 2012	Nov. 12, 2012

REVISION HISTORY

DATE	VERSION	COMMENTS
Feb 27, 2012	xx	Initial Draft
Aug 31, 2012	R0	New

This page is intentionally left blank.

ACKNOWLEDGEMENTS

Special thanks to the following personnel, for their assistance during the project work as well as the valuable information they provided during critical meetings and discussions.

Andrea Valença	Hydro One
Paul DiFilippo	Hydro One
Arend Koert	Kinectrics
Mansour Jalali	Kinectrics

This page is intentionally left blank.

EXECUTIVE SUMMARY

The objective of this project is to study the end of life (EOL) for intelligent electronic devices (IED), especially digital protective relays. With the trend of implementing digital protective relays to replace the existing electromechanical or solid-state relays in the power system, knowledge of the expected EOL for such relay population is of vital importance for utilities to set up a maintenance schedule as well as an annual capital replacement.

It is necessary to clearly define the EOL in a mathematical way. Although EOL happens on a singular digital relay when its major functionality ceases to work, for the asset group of digital relays in a utility, the EOL is interpreted by means of probability and statistics.

Digital relays consist of various functionality modules and the involvement of hundreds of electronic components. Different ageing mechanisms exist among these components. This report attempts to highlight the major components that, compared with all other ones, are more likely to fail earlier. Specific ageing mechanisms are also explained in detail.

Different approaches in determining the EOL of digital relays are introduced. Depending on the available resources and schedules, a utility can determine the EOL based on historic failure records on the digital relays, by conducting an accelerating life test on sample units, or by approximate estimation of EOL based on theoretical formulas.

Both manufacturers and industrial end-users have publications on the life estimate of digital relays. Through literature review, it is found that the manufacturers’ lifetime data are mainly useful for annual failure rate estimates, rather than a true EOL. Meanwhile, the lifetime data from other industrial end-users provides useful information on EOL, which is, however, only applicable to specific operational environments.

It is recommended, in terms of determining the EOL for digital relays in the short-term, that Hydro One start with approximate estimation based on theoretical formulas applying the actual operational environment condition (e.g. temperature, humidity). In the mid-term, Hydro One might refine the EOL results by conducting accelerating life tests on sample units of digital relays. In the long-term, Hydro One needs to collect all the historic failure records so as to obtain the EOL results in a statistical way, which reflects the actual EOL at asset group level under the Hydro One operational environment.

TABLE OF CONTENTS

Page

1 PROJECT OBJECTIVE AND SCOPE 1

1.1 Project objectives 1

1.2 Scope of Work 1

2 RELIABILITY FEATURES IN DIGITAL IED EOL STUDY 3

2.1 Understanding reliability parameters 3

2.2 Mathematical models adopted in EOL study 6
2.2.1 Probability density function and IED life parameters 6
2.2.2 Different types of failure rate 8

3 DIGITAL IED AGEING MECHANISM 11

3.1 Analog/Digital Input Section 13

3.2 Processing section 14

3.3 Output section 15

3.4 Power supply section 17

3.5 Major ageing mechanisms 17

4 APPROACHES IN PREDICTING DIGITAL IED EOL 21

4.1 EOL approaches based on statistics 21

4.2 EOL approaches based on accelerating life test 24
4.2.1 Accelerating life test methodology 24
4.2.2 Quantification of accelerating life test results 26
4.2.3 Quantified accelerating life test for digital IEDs 28

4.3 EOL approaches based on modeling 32
4.3.1 EOL for electrolytic capacitors 33
4.3.2 EOL for power transistors and diodes 33
4.3.3 EOL for ZnO varistors 34
4.3.4 EOL for opto-couplers 34
4.3.5 EOL for microprocessors/controllers 34
4.3.6 EOL for output electromechanical relays 35

5 INDUSTRIAL DATA ON DIGITAL RELAY EOL 37

5.1 Publications from manufacturers 37

5.2 Publications from researchers and end users 38

5.3 Data records from Hydro One 39

6 CONCLUSIONS 41

7 RECOMMENDED APPROACHES FOR HYDRO ONE DIGITAL RELAYS 43

8 REFERENCES 47

GLOSSARY 51

INDEX 53

LIST OF TABLES

Page

TABLE 3-1 STATISTICAL DATA ON DIGITAL RELAYS FAILURE SURVEY [30] 12
TABLE 3-2 AGEING FACTORS FOR SIMPLE COMPONENTS IN DIGITAL IEDS 17
TABLE 4-1 MAXIMUM FAILURE NUMBER VS. SAMPLE SIZE [31] 26

LIST OF FIGURES

Page

FIGURE 2-1 TYPICAL BATHTUB CURVE [4] 3
FIGURE 2-2 PROBABILITY DENSITY FUNCTION AND USEFUL LIFE PARAMETERS 6
FIGURE 2-3 MODELLING OF BATHTUB CURVE FOR IED FAILURE CHARACTERS 9
FIGURE 3-1 DIGITAL IED ARCHITECTURE [8] 11
FIGURE 3-2 ANALOG INPUT MODULE OF EXAMPLE IED 13
FIGURE 3-3 DIGITAL INPUT MODULE OF EXAMPLE IED 14
FIGURE 3-4 CPU MODULE OF EXAMPLE IED 15
FIGURE 3-5 OUTPUT DRIVE MODULE OF EXAMPLE IED 16
FIGURE 3-6 OUTPUT RELAY MODULE OF EXAMPLE IED 16
FIGURE 3-7 POWER SUPPLY MODULE OF EXAMPLE IED 17
FIGURE 4-1 EXAMPLE OF PROBABILITY OF FAILURE VS AGE 22
FIGURE 4-2 EXAMPLE OF PROBABILITY DENSITY FUNCTION 23
FIGURE 4-3 EXAMPLE OF FAILURE RATE 23
FIGURE 4-4 ACCELERATED LIFE TEST BASED ON ARRHENIUS RELATIONSHIP [33] 27
FIGURE 4-5 EXAMPLE OF MULTI-STRESS ACCELERATED LIFE TEST [34] 30
FIGURE 4-6 EFFECTIVENESS COMPARISON --- THERMAL VS ELECTRICAL STRESSES [32] ... 31

1 PROJECT OBJECTIVE AND SCOPE

This project is funded by Hydro One to provide information related to the end-of-life for digital relays, and to identify the means with which to assess IED conditions. Data from industry (PSRC, IEC, CIGRE, CEATI, etc.), if available, should be reviewed. Several items can be observed such as typical MTBF provided by manufacturers, major failures in IEDs, external environmental and operating conditions that accelerate the aging process, identification of components which are more likely to fail, etc. The outcome of this project should help with the identification of mechanisms to effectively estimate the EOL of IEDs and therefore support strategic planning decisions with regards to IED replacements.

1.1 Project objectives

Overall, the objectives for this project are:

- To provide information related to the EOL for digital IEDs
- To identify the means with which to assess digital IED conditions
- To recommend approaches to effectively estimate EOL of digital IEDs so as to support strategic planning decisions with regards to digital IED replacements in Hydro One

1.2 Scope of Work

Starting from the requirements of Hydro One, the scope of work of this project falls into the following three major categories:

- Clear definitions of the major technical and statistic parameters that are related to the EOL of digital relays

- Analysis of the dominant ageing mechanisms of the major components inside digital relays
- Proposed quantitative approaches to determine the EOL of digital relays based on lab tests and statistical records

2 RELIABILITY FEATURES IN DIGITAL IED EOL STUDY

In decision-making by end-users regarding the replacement of a certain type of IED, the EOL value is one of the top priority factors that must be taken into account. The EOL of an IED is related to its reliability features, which are characterized based on the statistics of IED failures in practical operation.

In this chapter, detailed discussions address various types of reliability parameters as well as the mathematical models for depicting IED reliability features.

2.1 Understanding reliability parameters

Generically speaking, the population of a specific type of industrial product follows a "Bathtub Curve" for its failure rate. The following figure shows this typical curve.

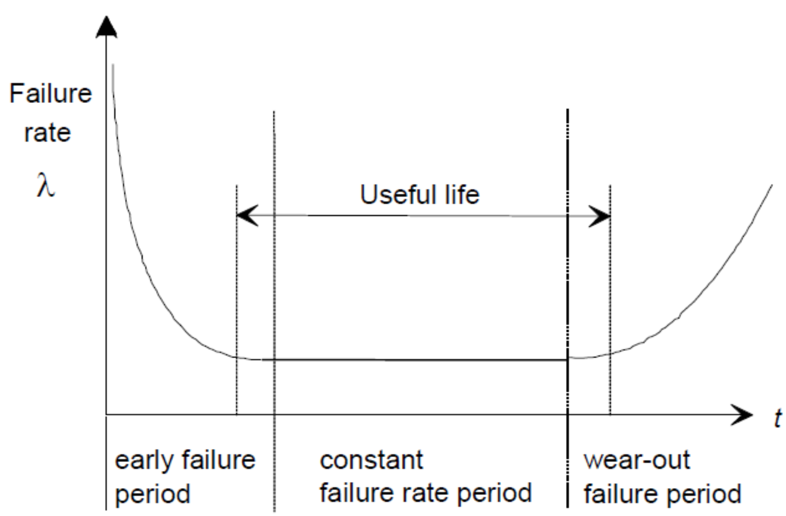


Figure 2-1 Typical Bathtub Curve [4]

The interpretation of the above curve can be summarized as follows:

- The entire population of a product shows different failure rates at different stages of the lifecycle
- The early failure period shows a decreasing failure rate with time elapses
- The wear-out failure period shows an increasing failure rate with time elapses
- The useful life period shows a relatively stable failure rate

The early failure period (also called the infant mortality period) consists of failures due to poor workmanship or weak components. In spite of using all available up-to-date design tools and manufacturing processes, there will still be some early failures due to the instability of the process control at the molecular level. Many components fail shortly after they are put into service. How long this takes depends on the component; for example, processors sometimes fail as soon as they are first put into a system. Many other parts fail within a week or a month of the usage start date. To tackle the issue, normally stress screening (also called the burn-in process) is applied to weed out some of the new products that are doomed to fail during the early failure period. In other words, all new products are intentionally aged by manufacturers. Only the ones that survive such a process and enter their useful life period are then delivered to end-users. This stress screening applies to both the component level and device level.

The product enters the wear-out period (also called the end-of-life period) when components begin to fatigue or deplete. In this area of the graph, the product shows a drastically increasing failure rate due to its own accelerated ageing mechanism after reaching its useful life limit. For example, wear-out in power supplies is usually caused by the breakdown of electrical components that are subject to physical wear, as well as electrical and thermal stress.

The useful life period represents the time when the failures are typically random and caused by “stress exceeding strength”. Under such a process, the failure rate is approximately low and constant, showing the so-called memory-less character (i.e. whether or not there has been a failure before does not impact the probability of failure right now).

While both ends of the Bathtub curve provide helpful information regarding the failure mechanism of the product, in most cases, only the useful life period is of primary concern to both the manufacturers and the end-users, as it is useful in predicting the annual product replacement and assessing product reliability.

The EOL of a product is, however, end-user dependent. For some utilities, this is the same as the useful life of a product. For some others, this refers to the time when the probability of failure (POF) reaches a pre-set limit. These two parameters are not necessarily equal to each other mathematically. In this project, EOL is defined to be the same as the useful life.

Also in the case of an IED product, a utility maintenance program normally requires replacement of the IED at failure (functional inability). This means in the study of this project, MTBF does not apply. To facilitate the quantification of the length of usage of an IED product, it is suggested that in this project only MTTF be studied and MTBF be ignored.

It is worth mentioning that in some cases, only the faulty component (e.g. an analog input card in an IED device) must be replaced upon IED failure. Utilities may argue that, in such a scenario, it is MTBF that is impacted since the IED is reusable after such component replacement. This is true. However in this project, the key question is how should utilities treat these “refurbished” IEDs in failure statistics?

To Kinectrics’ understanding, if an IED’s functionality cannot be restored following simple intervention onsite by maintenance staff within a reasonably short period of time, it will be determined a failure, and only once in failure statistics for EOL. Any failures after the refurbishment only contribute to reliability. The reason is that a mixture of old and new components in a refurbished IED deteriorates at the same pace as a new IED. Therefore, only the first failure provides useful information in determining EOL, while the failures after refurbishment provide information to determine the reliability during the useful life period.

2.2 Mathematical models adopted in EOL study

This section will address the mathematical models behind the parameters defined in section 1.3. To start with, the diagram of the probability density function is introduced for clarification of certain mathematical concepts.

2.2.1 Probability density function and IED life parameters

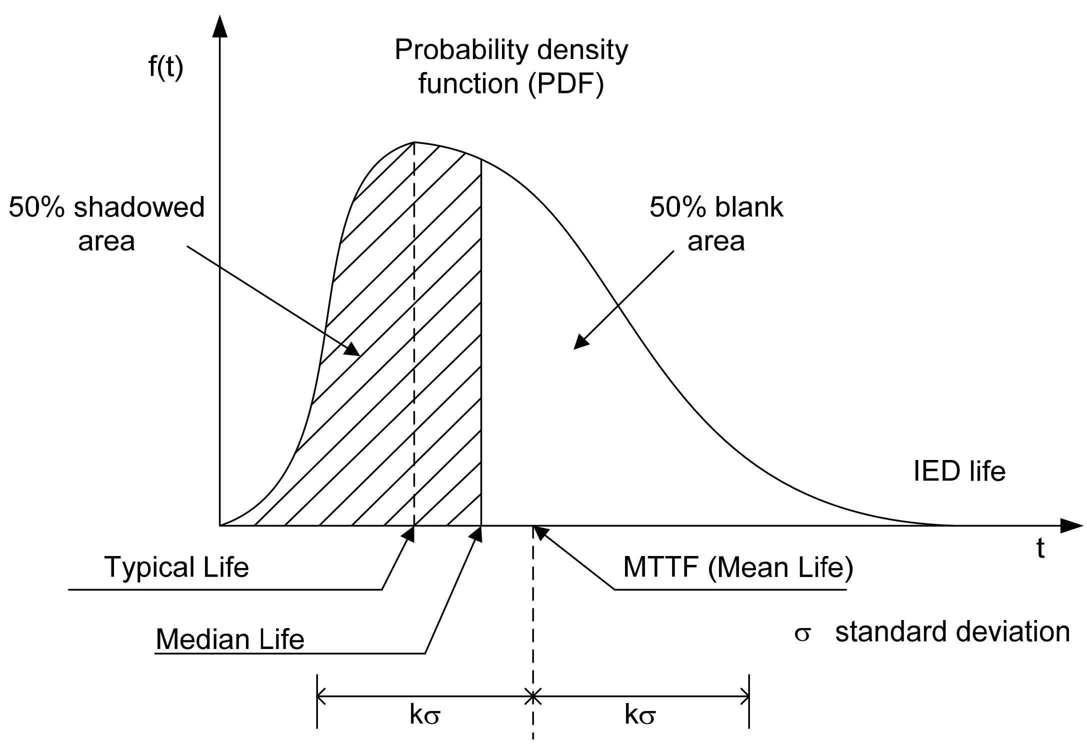


Figure 2-2 Probability density function and useful life parameters

The above diagram shows a generic product failure distribution. The curve is for the probability density function (PDF), expressed as f(t).

The cumulative probability of failure up to time t is defined as the area under the f(t) curve from 0 to time t, expressed as F(t).

$$F(t) = \int_0^t f(t)dt$$

The reliability is defined as the probability that a product can survive up to time t, expressed as R(t).

$$R(t) = 1 - F(t)$$

The failure rate is expressed as h(t).

$$h(t) = \frac{f(t)}{R(t)}$$

MTTF is calculated using the same expression as follows:

$$MTTF = \int_0^\infty tf(t)dt = \int_0^\infty R(t)dt$$

The following statements explain the physical meanings of the aforementioned three types of life data:

MTTF (Mean life) is the arithmetic average of life expectancy of the whole IED population.

Median life refers to the time when 50% of the whole IED population will fail before such an age.

The meaning of typical life is: there will be more singular IED sets that fail at this age than at any other time.

The following example demonstrates the difference between these three parameters.

Assume there are 10 IEDs that fail respectively at the age (years) of

17, 17, 17, 18, 20, 20, 22, 23, 35, 40.

Then $MTTF = \frac{17+17+17+18+20+20+22+23+35+40}{10} = 22.9$

Correspondingly, the median life is 20 and the typical life is 17.

2.2.2 Different types of failure rate

As can be observed from the mathematical expressions in the previous section, the failure rate is determined by probability density function. In probability theory and statistics, the Weibull distribution is adopted to describe various types of probability distribution. A generic formula for probability density function is:

$$f(t) = \frac{k}{\lambda}\left(\frac{t}{\lambda}\right)^{k-1} e^{-(t/\lambda)^k}$$

Where k > 0 is the shape parameter

λ > 0 is the scale parameter

The shape parameter k determines the slope of f(t), thus signifying the failure rate. When k<1, f(t) models a failure rate decreasing over time, which is the case of an early failure period. When k=1, f(t) models an exponential distribution in which failure rate is constant, which is the case of a useful life period. When k>1, f(t) models a failure rate increasing over time, which is the case of a wear-out period. For the cases of k>1, the higher k is, the faster the wear-out is. So one can say k=3 (corresponding to a normal distribution) to represent the early stage of a wear-out period and k=10 for a rapid wear-out stage.

Combining f(t) of various shape parameters yields a curve that is similar to the bathtub curve as defined in the previous section. The following diagram shows such an effect. Note that different scale parameters are applied for the single curves.

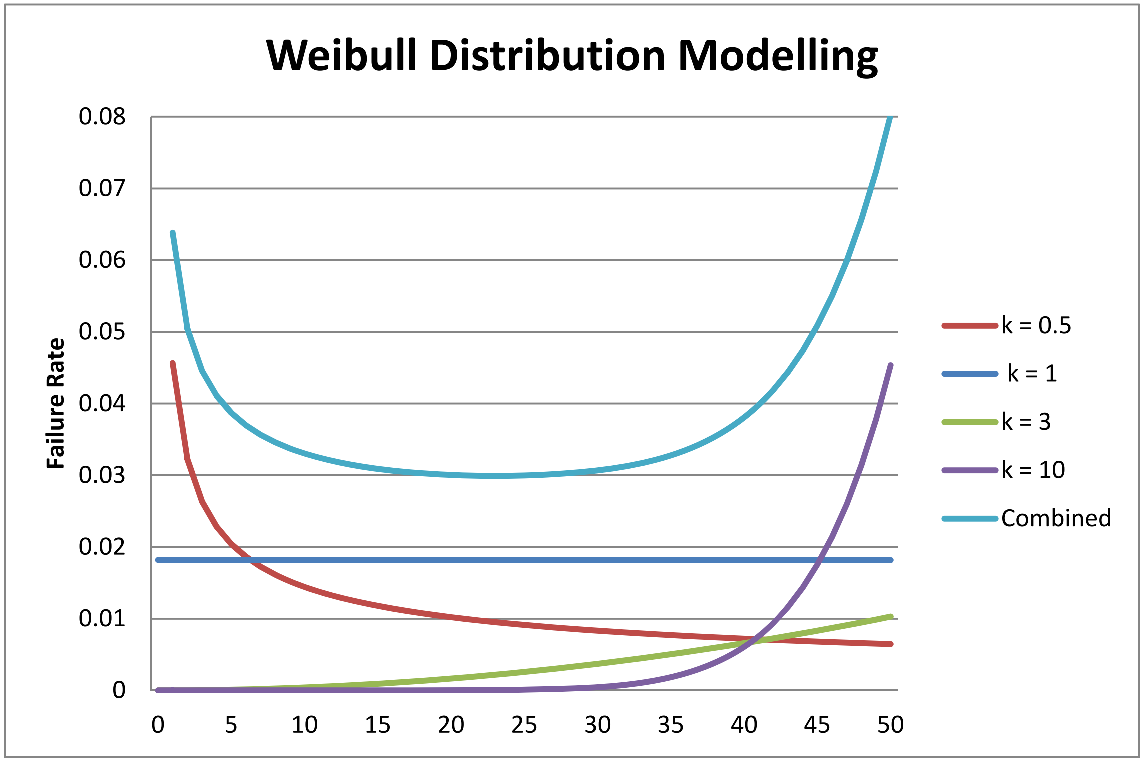


Figure 2-3 Modelling of Bathtub curve for IED failure characters

From the above, it can be observed that by combining various failure mechanisms with different Weibull functions, one can model the actual Bathtub curve for the IED failure rate. As in this project, the focus is on the useful life period, so one can use a Weibull function of k=1 to represent such a constant failure rate scenario.

The EOL is reached when statistical data show that the constant failure character does not hold any more.

This page is intentionally left blank.

3 DIGITAL IED AGEING MECHANISM

The following diagram shows the architecture of a typical digital IED.

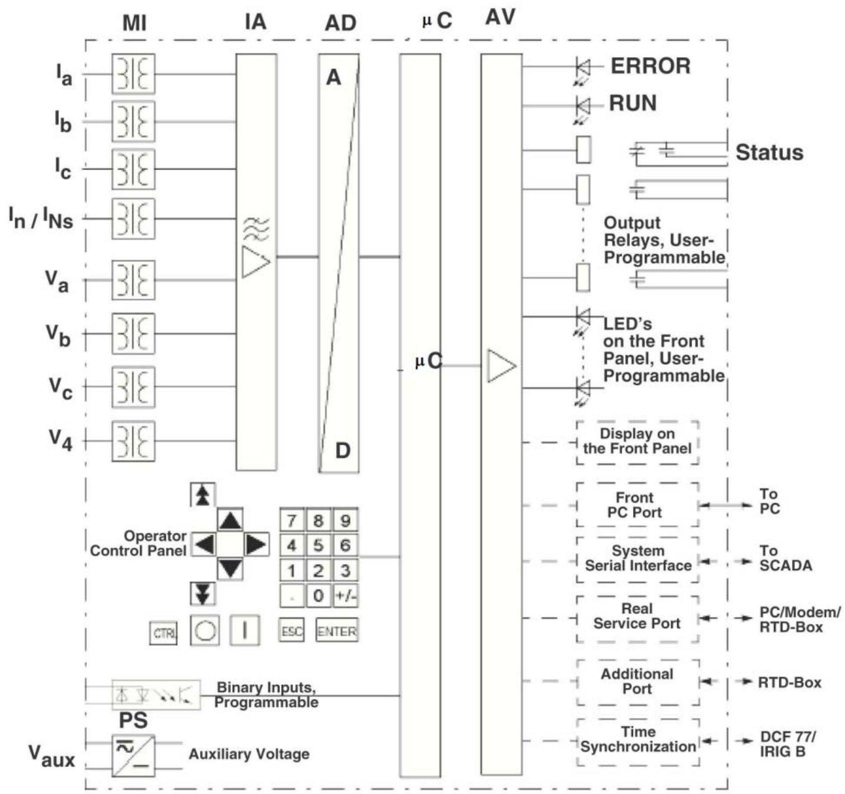


Figure 3-1 Digital IED architecture [8]

In this chapter, detailed discussions are made on various ageing mechanisms of digital IEDs at the component level.

In general, an Intelligent Electronic Device (IED) contains the following major ageing components:

- Analog/digital input section
- Processing section
- Output section
- Power supply section

As per existing studies, the following major categories of components used in digital IEDs are more sensitive to ageing effects than others [15]:

- Electrolytic capacitors
- Power transistors and diodes
- Varistors/Resistors
- Opto-couplers
- Microprocessors/controllers and memories
- Output auxiliary electromechanical relays

Other existing studies provide statistical surveys on the failure modes of digital relays. The results confirm that the major ageing components are as mentioned above. Details are shown in the following table. Note that the crystal oscillator in this table can be considered as a special type of transistor. This table does not include human errors, i.e. failures of the IED as a result of human mistakes during IED installation / operation / maintenance, which do not comply with procedures specified by manufacturers.

Table 3-1 Statistical data on digital relays failure survey [30]

Failure Root Cause	Percentage
Poor wiring contacts/foreign matter inclusion	4.3%
Soldering	5.9%
Resistors, Connectors etc	6.4%
Capacitors	5.3%
Transistors, Diodes, Opto-couplers	7.0%
Crystal oscillators	8.5%
Auxiliary relays	9.6%
ICs (Microprocessors/controllers and memories)	53%

For the purpose of this demo in order to disclose the detailed architecture of a typical IED, an Ontario Hydro developed device (Programmable Auxiliary Logic Controller, PALC) is adopted. Such a device represents the technique of the digital IED at an early stage. The aforementioned major components are highlighted in the following sections.

3.1 Analog/Digital Input Section

The major components in this section are resistors, varistors, opto-couplers, transformers, AC/DC converters and processor/memory chips.

The following diagram shows the analog input module of an example IED. Note that in practice, an analog input module may have both CTs and PTs depending on its functionality design.

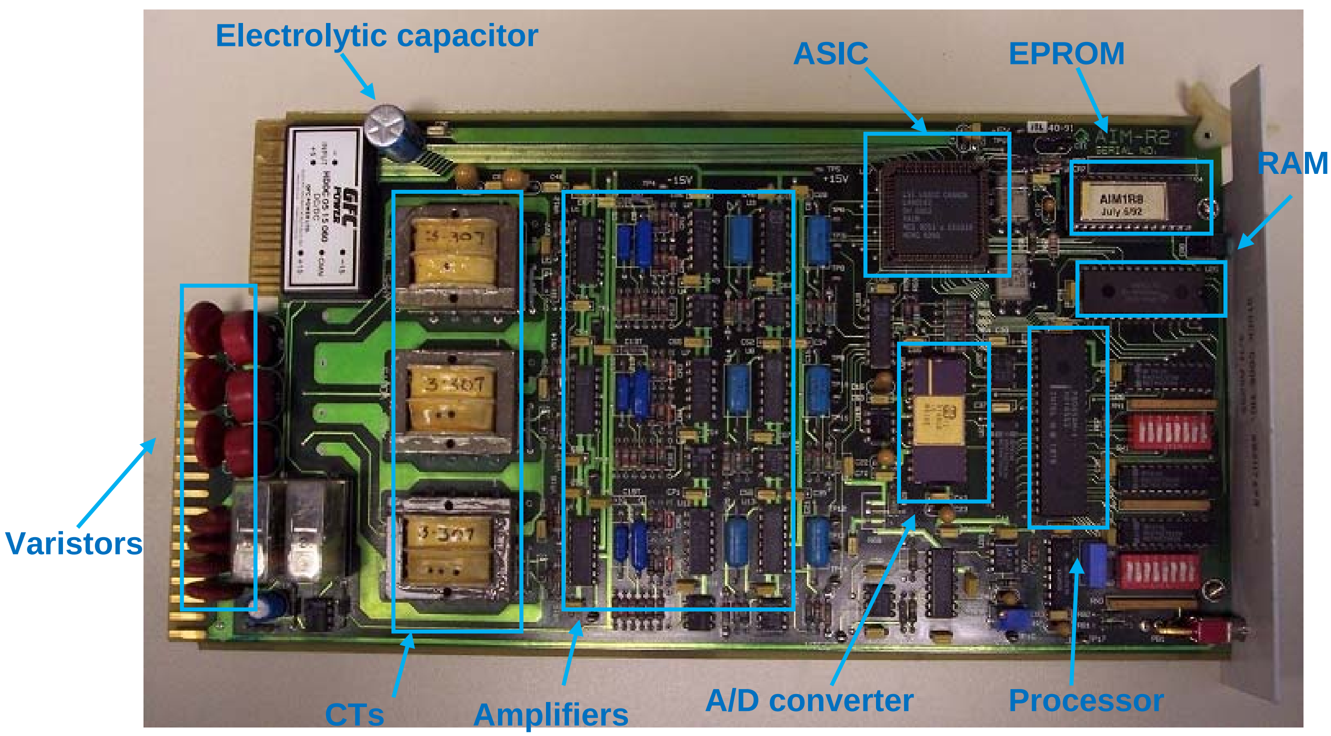


Figure 3-2 Analog input module of example IED

The following diagram shows the digital input module of an example IED.

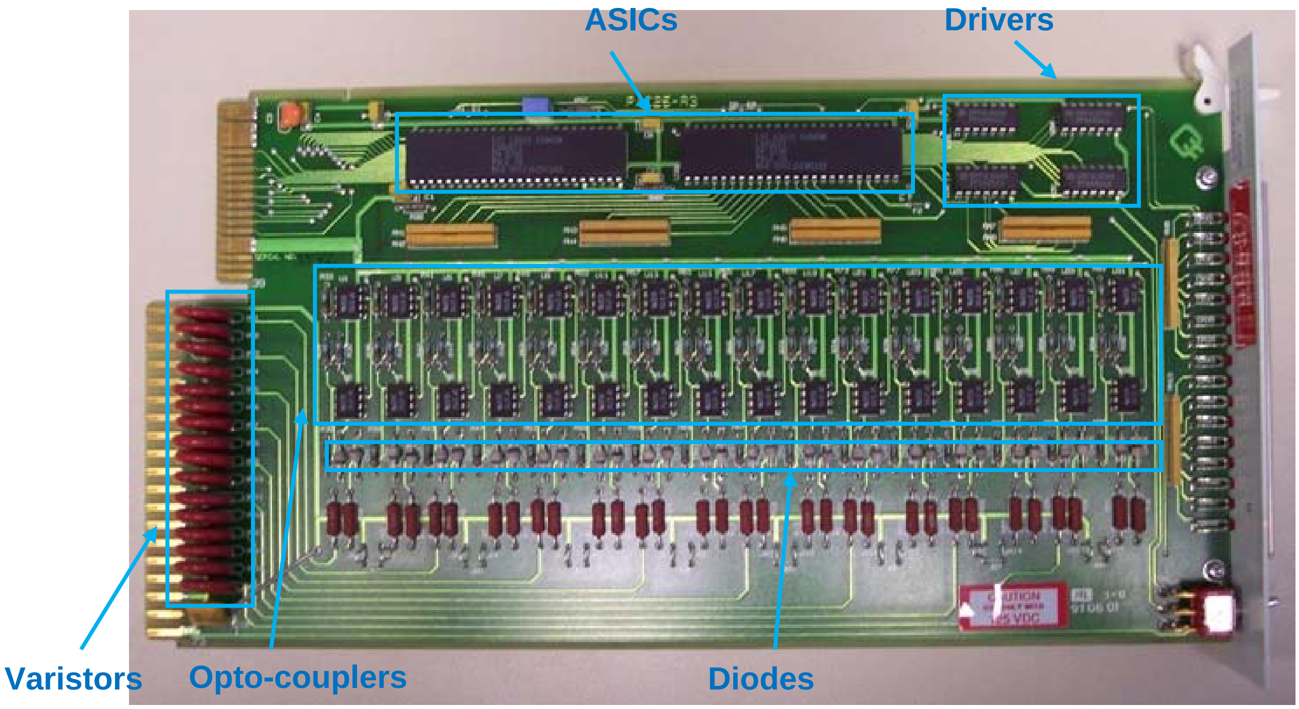


Figure 3-3 Digital input module of example IED

3.2 Processing section

This section consists of microprocessors/controllers (CPU) and memories (ROM, RAM, etc.).

The following diagram shows the CPU module of the example IED.

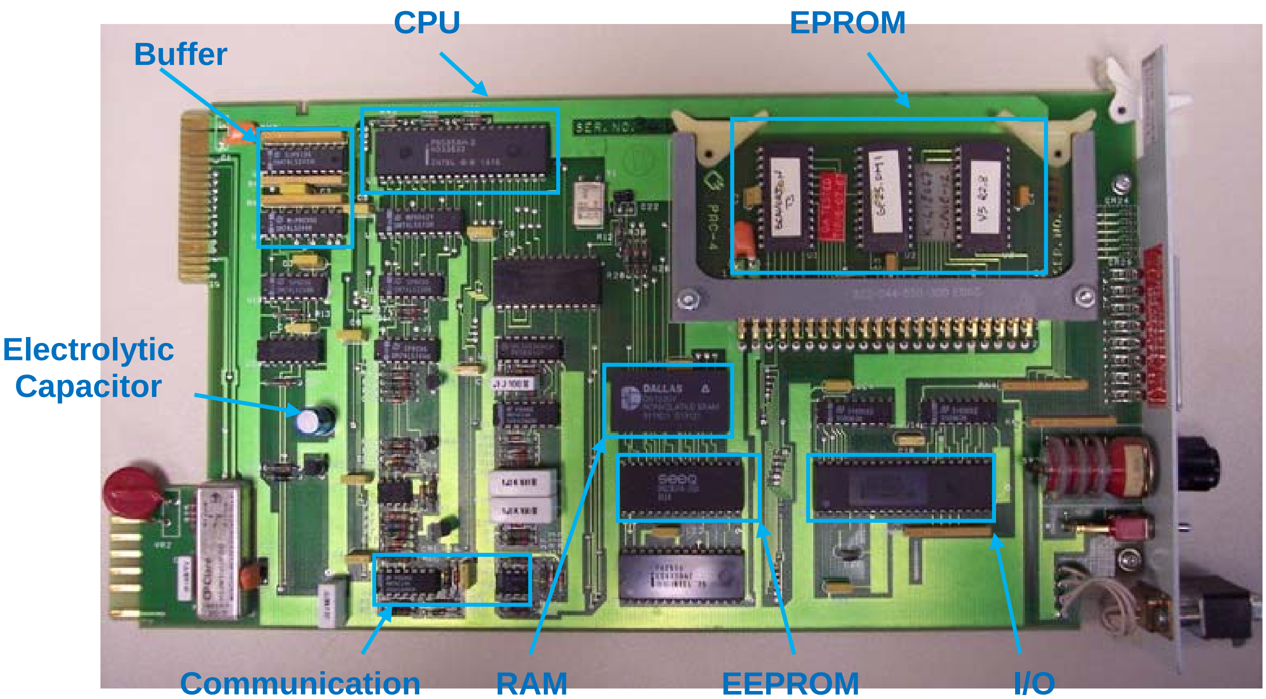


Figure 3-4 CPU module of example IED

3.3 Output section

This section consists of output elements, i.e. the contacts of the miniature electro-mechanical relays that directly control the trip coils of high-voltage circuit breakers or the coils of auxiliary relays with a significant overload.

Two modules are adopted for output in the example IED: an output driver module and an output relay module.

The following diagram shows the output drive module of the example IED.

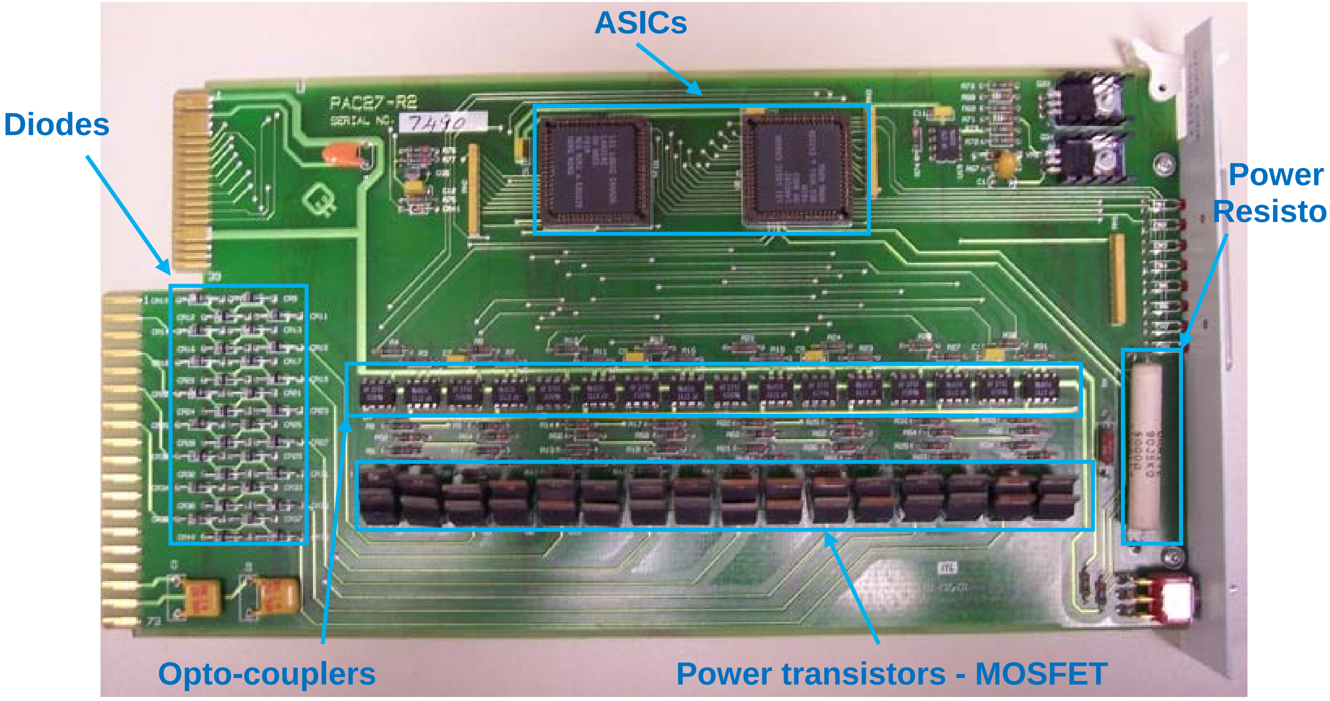


Figure 3-5 Output drive module of example IED

The following diagram shows the output relay module of the example IED.

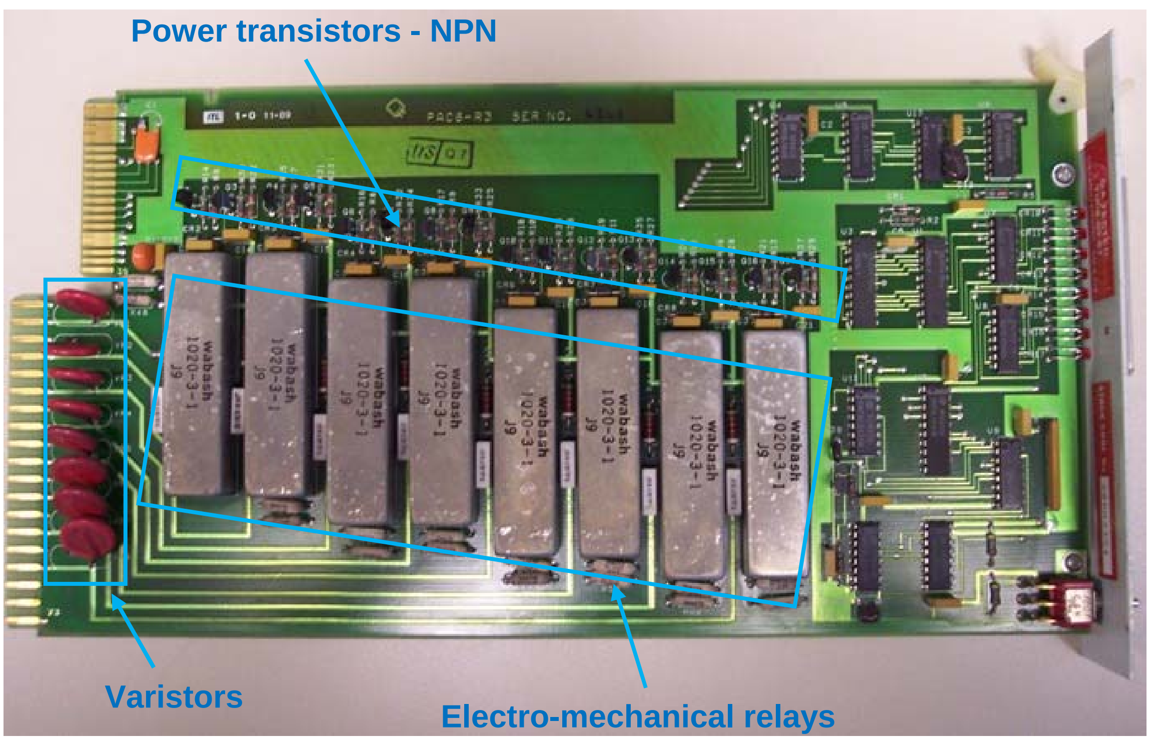


Figure 3-6 Output relay module of example IED

3.4 Power supply section

This section consists of the switching power supplies. The purpose of such supplies is to convert the input voltage (AC or DC) to a low DC voltage that feeds the circuits of IED device. A powerful high frequency switching transistor is required in such a design.

The following diagram shows the power supply module of the example IED.

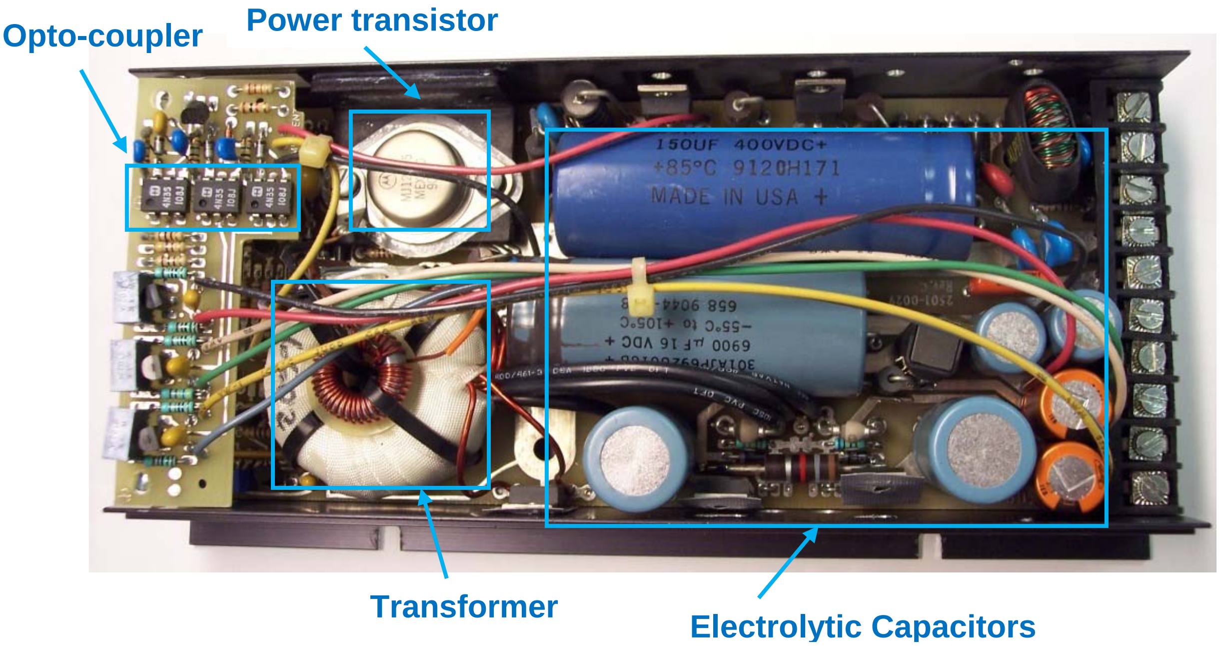


Figure 3-7 Power supply module of example IED

3.5 Major ageing mechanisms

For simple components such as the capacitor and diodes, the ageing mechanism is mainly due to thermal and electrical stresses. The following table shows the major contributing factors on the ageing of various components in digital IEDs.

Table 3-2 Ageing factors for simple components in digital IEDs

Component Type	Ageing Factors
Electrolytic Capacitors	Voltage, Current, Temperature
Diodes	Power, Temperature
Electromechanical Relays	Current, Load, Temperature
Transistors	Voltage, Power, Temperature

For other components (processors, memories, opto-couplers, other chips, etc.) that are based on micro-electronic techniques, their ageing mechanisms are somewhat complex. In general, the following factors determine their intrinsic wear-out:

- Electromigration (EM)
- Hot carrier degradation (HCD)
- Time-dependent dielectric breakdown (TDDB)
- Negative bias temperature instability (NBTI)

--- Electromigration (EM)

EM refers to the migration of metal atoms in a conductor through which large, direct-current densities pass. The following diagram shows the physics of this process. The so-called electron-wind force due to high current density can activate a large number of metal atoms and cause movement in the vacancies. Such movement can lead to a break or gap in the conducting material and can prevent the flow of electricity. This decreases the cross-sectional area of circuit metallization and increases local resistance and current density. In summary, the consequence of EM is a thermal runaway of interconnects.

--- Hot carrier degradation (HCD)

HCD refers to the hot electron effect occurring in semiconductor devices (e.g. MOSFET transistors) where electrons are excited to energy levels higher than those associated with the semiconductor's conduction band. These hot electrons can tunnel out of the semiconductor material—instead of recombining with a hole or being conducted through the material to a collector. Consequent effects of this phenomenon include heating of the device, and increased leakage current. Because hot electrons generally give off their excess energy as phonons, a common manifestation of the hot electron effect is an increase in the heat of the semiconductor device.

--- Time-dependent dielectric breakdown (TDDB)

TDDB is a wear-out phenomenon of SiO2, the thin insulating layer between the control gate and the conducting channel of the transistor. The general belief is that a driving force such as a high enough applied voltage can create a high electric field, providing enough energy for the conductor electrons above or below the oxide to jump the energy barrier separating the electrons from the oxide. The resulting tunneling electrons (the so-called Fowler-Nordheim tunneling current) create defects in the volume of the oxide film. The defects accumulate with time and eventually reach a critical density, triggering a sudden loss of dielectric properties. A surge of current produces a large localized rise in temperature, leading to permanent structural damage in the silicon oxide film [28]. This mechanism causes the dielectric to break down and become electrically shorted after a certain period of time has passed during operation.

--- Negative bias temperature instability (NBTI)

NBTI occurs to p-channel MOS devices under negative gate voltages at elevated temperatures. Bias temperature stress under constant voltage causes the generation of an interface trap between the gate oxide and silicon substrate, leading to a device threshold voltage shift and a loss of drive current.

For a micro-electronics based component, the dominant ageing mechanisms are in many cases a combination of the aforementioned factors. For each factor, there are various models developed to depict its physical process for simulation, failure statistics or the purpose of lifetime estimation. In a prediction of the digital IED EOL, a coordination supported by empirical data is needed in order to merge these competing models from a component level to a module level or device level.

This page is intentionally left blank.

4 APPROACHES IN PREDICTING DIGITAL IED EOL

The EOL of a digital IED can be predicted in three approaches:

- Statistics --- To set up failure distribution functions based on historic failure records of the digital IED population
- Test --- To apply accelerating stress tests on a new digital IED and calculate the EOL based on the test results
- Modeling --- To calculate the EOL by simulating an ageing mechanism

4.1 EOL approaches based on statistics

In this approach, one needs to collect sufficient information on the ages of the digital IEDs when they fail for a specific type of digital IEDs. Bear in mind that the failure here represents a loss of IED functionality, which is due to irreparable damage on the IED components.

Starting from the information retrieved on the IED failure date, one can calculate, for the failure of the digital IEDs, the cumulative distribution function F(t), which represents the relationship between the probability of failure and time. The POF at age t is calculated by:

$$POF\ (t) = \frac{number\ of\ units\ that\ have\ failed\ before\ age\ t}{number\ of\ units\ of\ the\ whole\ population}$$

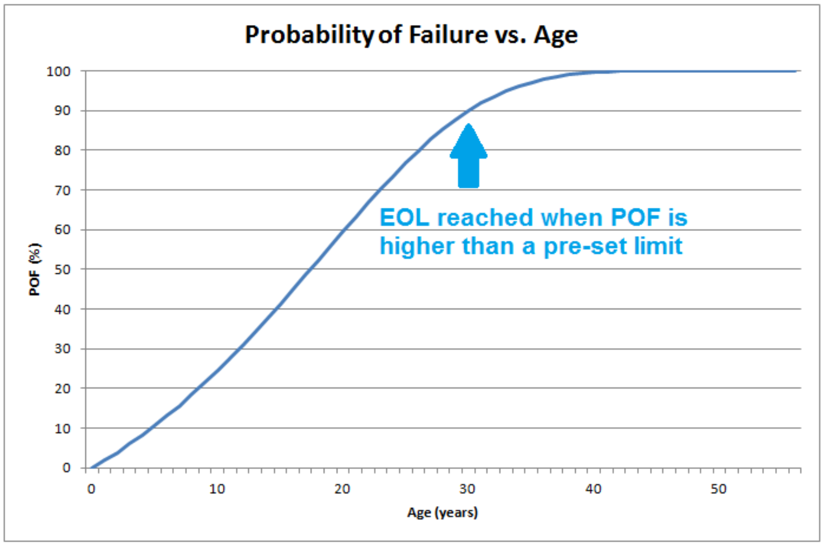


Figure 4-1 Example of probability of failure vs age

If the end-user determines the EOL based on the population probability of failure, the EOL can be obtained by checking the time when a pre-set POF limit is reached on the POF curve.

If the end-user determines the EOL based on the failure rate bathtub curve, then the following procedures are followed.

- Take the derivative at each point on the F(t) curve to yield a probability density function f(t), which represents the failure distribution.

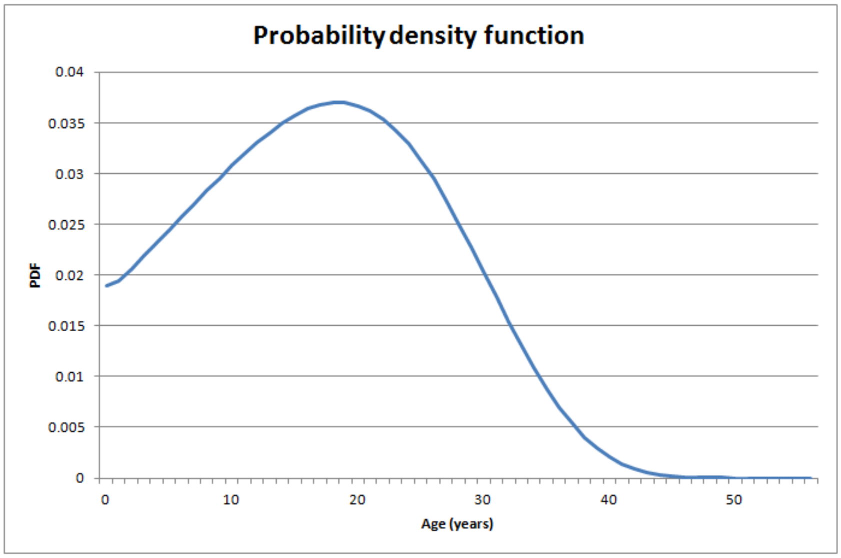


Figure 4-2 Example of probability density function

- The failure rate h(t) is obtained by h(t) =f(t)/(1-F(t))

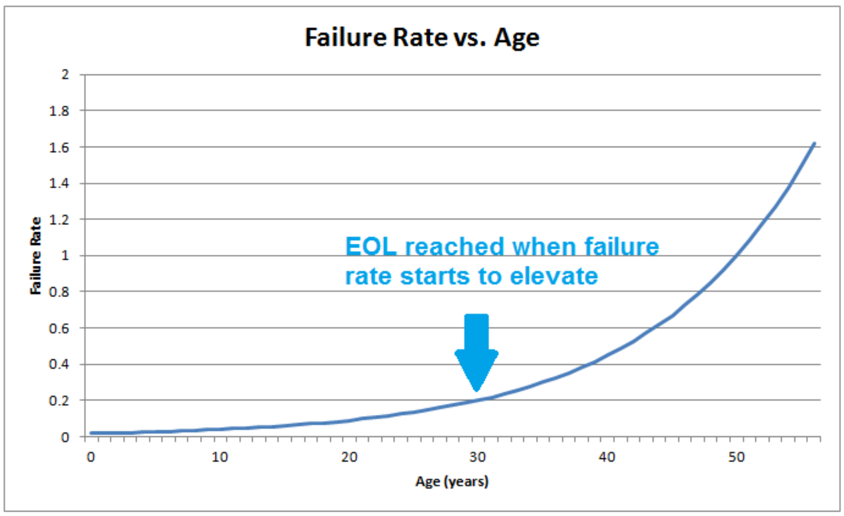


Figure 4-3 Example of failure rate

The EOL is obtained by looking up the failure rate curve for the time when the population failure rate starts to elevate.

Although statistically feasible, the implementation of this approach is challenging to utilities as it requires years or even decades of failure record tracking. Furthermore, utilities must make additional efforts to distinguish, through data mining on their work orders, the failures that are reparable (e.g. can be restored via rebooting, rewiring or re-calibration) from the ones that are irreparable (e.g. need to be replaced). Nevertheless, such an approach will definitely benefit utilities in the long run.

4.2 EOL approaches based on accelerating life test

In this approach, a device under study is exposed to an accelerating life test that lasts for a period of time substantially shorter than the useful life of the unit, so as to estimate the EOL by extrapolating the test results.

4.2.1 Accelerating life test methodology

In general, there are two major methods of acceleration: usage rate acceleration and overstress acceleration.

Usage rate acceleration is adopted for devices that do not operate continuously under normal conditions. In such a case, the accelerating life test puts a device into non-stop operation while keeping the other operating conditions (ambient temperature, load, etc.) unchanged.

Overstress acceleration is adopted for devices with high or continuous usage. In such a case, the accelerating life test is applied to a device by imposing elevated operation stress (temperature, voltage etc.).

In the case of digital IEDs, the overstress acceleration method is applicable. The operation stresses are the ageing mechanism factors discussed in previous sections.

With the applied overstress acceleration method, the appropriate test response approach must be determined as well. Typically there are two types of response approaches:

1) The accelerating life test is applied to a large quantity of sample devices for a fixed time period with a number of break points. At each break point during the test, the total number of failed devices is counted.
2) The accelerating life test is applied to only one sample device until it fails.
3) The accelerating life test is applied to a minimum number of sample devices for a pre-set time period. At the end of the test, count the total number of failed devices.

The first one might yield more valuable information for the EOL estimation as its results can be used for building up failure statistics for an asset population. However, the major challenge is that it is impractical to apply the accelerating life test on many digital IEDs of the same type.

In the second approach, the test duration is somewhat unpredictable unless one has knowledge on the design and destruct limits for a device. The underlying assumption in its application is that the sampled device is a typical unit that represents the mean (expected) value for the whole population.

Compared with the first 2 approaches, the third approach is more feasible in practice. In such an approach, both the sample size and the test duration are in control. This diminishes the uncertainty that the sample device is not typical, while minimizing the test time by limiting the sample size. Depending on the required confidence level and reliability target, a small sample size and its maximum failure number are determined, so that at the end of the accelerating life test, one can tell if a failure rate target is met or not. In Kinectrics' previous report [31], an example of the relationship between the sample size and maximum failure number is shown in the following table. The example studies whether or not an IED model has at least a 70% chance to survive after being in service for 20 years, with a confidence level of 90%. In this specific case, the minimum sample size is 7.

Table 4-1 Maximum failure number vs. sample size [31]

Sample Size	Maximum Failure Number
7	0
12	1
16	2
20	3

In all the cases, theoretically, at least two different levels of higher-than-normal stress must be applied in order to extrapolate the EOL at normal operation stress. However, in specific situations, only one stress level is needed if certain parameter information is known as priority. This is addressed in the following section.

4.2.2 Quantification of accelerating life test results

In the quantification of accelerating life test results, the most popular model is based on the so-called Arrhenius relationship, a procedure which predicts the long-term performance characteristics of non-metallic (may also apply to certain products made of metal) materials. Such a technique has been described in the following standards or guides: UL Standard 746B, IEEE Standard 101 and IEC Publication 216-.1. A typical expression of an Arrhenius relationship is shown in the following formula:

$$L(s) = Ce^{\frac{B}{S}}$$

(Equation 4-1)

Where L(s) Lifetime at stress level S

S Stress level

B Model parameter to be determined

C Model parameter to be determined, >0

In accelerating life tests, the above relationship is normally linearized and plotted on a life vs. stress plot, also called the Arrhenius plot. The following expression shows the linearized form:

$$\ln(L(s)) = \ln(C) + \frac{B}{S}$$

(Equation 4-2)

The following diagram depicts the application of an accelerated life test based on an Arrhenius relationship. Note the Life axis is a scaled natural logarithm. R stands for reliability.

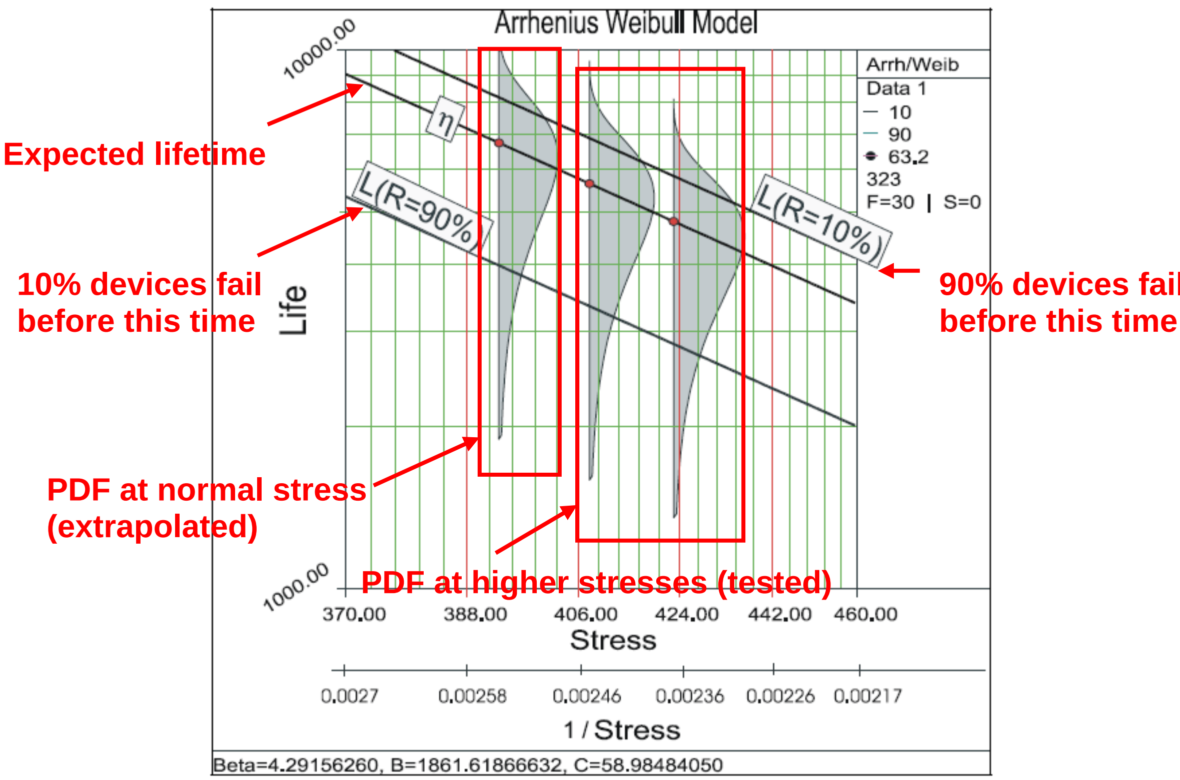


Figure 4-4 Accelerated life test based on Arrhenius relationship [33]

The procedures to apply an Arrhenius-based accelerated life test can be summarized as follows:

1) A higher-than-normal stress level is applied to a population of devices under testing. At different break points during the test, count the number of devices that fail. Work out the probability density function f(t) at such stress levels.

2) Repeat the same steps as in 1), but at different higher-than-normal stress. Work out the f(t) at the second stress level.
3) Plot the two groups of Life vs Stress data on the diagram as shown in Figure 4-4. Draw a family of straight lines based on this data (take one point from each of the two groups). Extrapolate the corresponding f(t) at a normal stress level (or any wanted stress level) to obtain the lifetime values.

The above procedures are based on the assumption that a large number of sample devices are used in the test. However, as mentioned in the previous section, in practice, people tend to take only a few sample devices for the accelerated life test. In such a case, the above procedures are to be modified as follows:

1) A higher-than-normal stress level is applied to one sample device under testing. The test is run until the sample device fails. Record the lifetime when the device fails.
2) Repeat the same steps as in 1), but at different higher-than-normal stress levels. Record the lifetime of the sample device at the second stress level.
3) Plot the two Life vs. Stress points on the diagram as shown in Figure 4-4. Draw a straight line with the two points. Extrapolate the corresponding expected lifetime (mean value) at a normal stress level.

This is based on the assumption that a typical sample device is used in this test, so that the lifetime test result is the same as the expected lifetime for the whole population. Such an approximation makes it feasible to estimate the device's EOL when there are only a limited number of sample devices available.

4.2.3 Quantified accelerating life test for digital IEDs

In the cases of digital IEDs there are two scenarios that require further discussion:

a) Digital IED components where a thermal effect is the dominant ageing factor
b) Digital IED components where there are more than one dominant ageing factor

For scenario a), the accelerated life test approach discussed in the previous section can be further simplified by replacing parameter B with:

$$B = \frac{E_A}{K} = \frac{activation\ energy}{Boltzman's\ \ constant} = \frac{activation\ energy}{8.623\ \times\ 10^{-5}}$$

(Equation 4-3)

If the activation energy is known (unit: eV), one can obtain the B parameter value. As a consequence, one needs to conduct an accelerated life test at only one higher-than-normal stress level to extrapolate the lifetime at a normal stress level.

For scenario b), a model other than Arrhenius relationship may need to be considered, as there exist non-thermal ageing factors for digital IEDs. A few typical models are listed as follows:

- Inverse power law relationship, used for non-thermal accelerating stresses (e.g. voltage) where the underlying life distribution is Weibull
- Eyringmodel, used for non-thermal fatigue
- Coffin Manson relationship, used when voltage variation ∆V is the stress

It is beyond the scope of work in this project to address the above models in detail. A sample diagram is provided below to depict the way one must tackle two ageing factors in one model.

Assume a device has two dominant ageing factors: temperature (thermal) and voltage (non-thermal). Arrhenius and the inverse power models can be combined to yield a so-called temperature-non-thermal (T-NT) model [33]. This model is given by:

$$L(U,T) = \frac{C}{U^n e^{\frac{B}{T}}}$$

(Equation 4-4)

where	U	voltage
	T	temperature (in absolute unit, K)
	B	ratio of activation energy over Boltzmann's constant

C and n parameters to be determined

In the acceleration life test, the same steps are followed as described in the previous section except that, at any test step, there is only one higher-than-normal stress applied while the other stress is kept constant. One must study two separate Life vs. Stress curves as shown below:

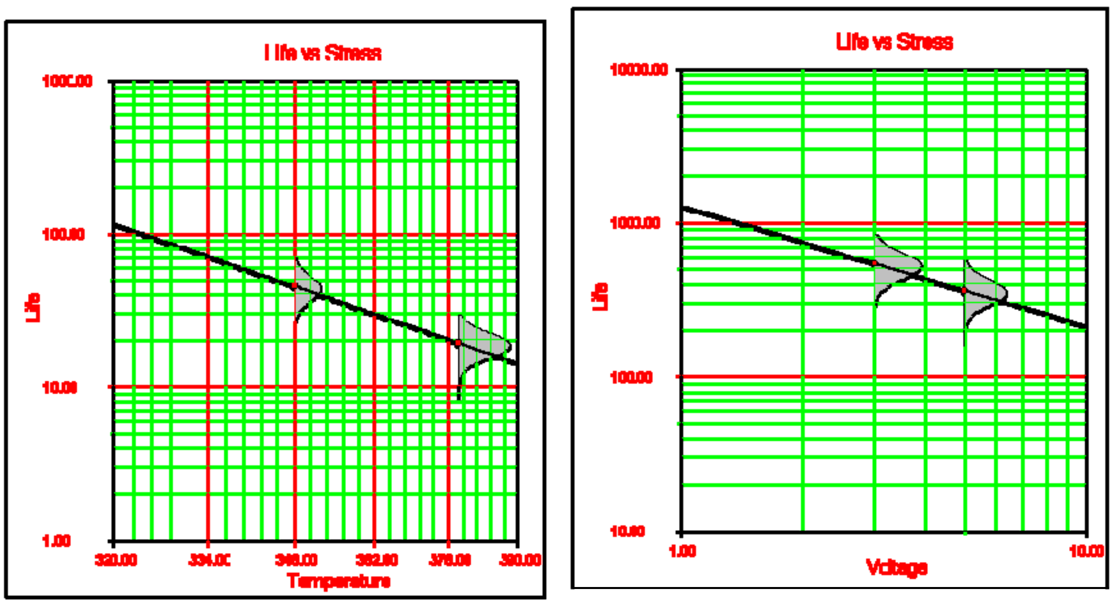


Figure 4-5 Example of multi-stress accelerated life test [34]

Note that in the above diagrams, for the temperature stress, the plot is on a log-normal scale, whereas the voltage stress is plotted on a log-log scale. Since there are a total of three unknown parameters in the above model, one possible test approach is to try a different combination of the 2 stresses as (U1, T1), (U1, T2) and (U2, T1), so as to obtain B, C and n in the formula.

Many practitioners use a term called the “acceleration factor”, which refers to the ratio of the life (or acceleration characteristic) between the use level and a higher test stress level:

$$A_F = \frac{L_S}{L_a}$$

(Equation 4-5)

Where L_s Ageing time at normal service stress

L_a Ageing time at accelerated stress

This ratio actually indicates the lifetime reduction percentage due to higher-than-normal applied stress. It has a direct impact on the failure rate of a specific type of device under testing.

Although for some components there are multiple stress factors, they are not necessarily of the same scale of importance. In practical testing, it is found that when it comes to effectiveness, it is reasonable to stick to only one major stress factor without sacrificing much of the result accuracy. In most cases, the thermal effect is the dominant stress factor. A publication from Envirotronics shows the comparison between thermal stress (temperature cycling) and electrical stress (voltage, current, power etc.).

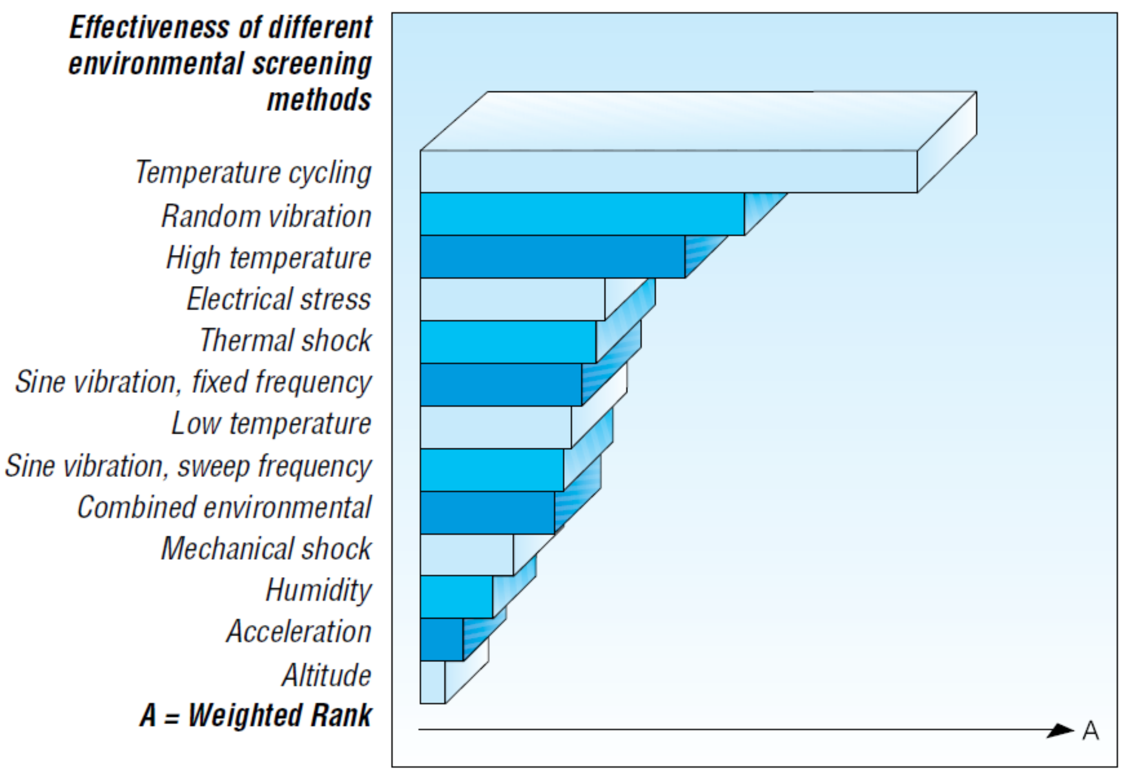


Figure 4-6 Effectiveness comparison --- thermal vs electrical stresses [32]

If a thermal effect is confirmed to be the major factor contributing to the ageing process, the acceleration factor can be deduced from (Equation 4-1) and (Equation 4-3):

$$A_F = \frac{L_s}{L_a} = \frac{C \cdot e^{\frac{B}{T_s}}}{C \cdot e^{\frac{B}{T_a}}} = e^{\frac{E_a}{8.623\times10^{-5}} \cdot \left(\frac{1}{T_s} - \frac{1}{T_a}\right)}$$

(Equation 4-6)

The above formula indicates that the proper selection of activation energy is very important, as it determines how fast the ageing process is.

4.3 EOL approaches based on modeling

Various models are developed to simulate the ageing mechanisms of components inside digital IEDs. These models are set up based on the physics-of-failure of the components. In this approach, the root cause of an individual failure mechanism is studied and corrected to achieve some determined lifetime.

The following sections introduce the mathematical formulas adopted by Schneider Electric [15] to estimate the approximate EOL at the component level, for the major ageing components as discussed in previous chapters.

Bear in mind that even if the end users have sufficient information to obtain the EOL for each major component, it is not recommended that the EOL be calculated at the device level based on this, as it requires a complex reliability study on the entire topology of the device functionality.

A practical way to obtain the EOL at the device level is to look for the weakest components that, if they fail, do have a major impact on the functionality of the device. The shortest EOL of such components can be used as the device's EOL.

4.3.1 EOL for electrolytic capacitors

For the ageing of chemical high power capacitors, the following equation is applicable:

$$L = L_0 \cdot 2^{\left(\frac{T_g + \Delta T - T_a}{10}\right)}$$

(Equation 4-7)

Where L EOL

L_0 base lifetime (or guaranteed) at the base temperature

T_g internal operating base temperature

T_a ambient temperature

ΔT 10 K (Kelvin) internal temperature increase (linked to T_g and L_o)

The above equation is based on the assumptions that:

- Actual current is the rated current and there is negligible ripple current
- Actual voltage is the rated voltage

4.3.2 EOL for power transistors and diodes

For the ageing of power transistors and diodes, the following equation is applicable:

$$L = (t_{on} + t_{off}) \cdot 10^7 \cdot e^{-0.05 \cdot \Delta T_j}$$

(Equation 4-8)

Where L EOL

ton time at ON position in an operating cycle

toff time at OFF position in an operating cycle

ΔT_j operating junction temperature variation in an operating cycle, from ON to OFF positions

4.3.3 EOL for ZnO varistors

For the ageing of ZnO varistors, the following equation is applicable:

$$L = e^{\left(-24+\frac{13129.7}{T_a}\right)}$$

(Equation 4-9)

Where L EOL

T_a ambient temperature (in Kelvin)

4.3.4 EOL for opto-couplers

For the ageing of opto-couplers, the following equation is applicable:

$$L = \frac{20}{I_f} \cdot K_1 \cdot K_2 \cdot K_3 \cdot e^{\frac{4640}{T_j}}$$

(Equation 4-10)

Where L EOL

I_f direct current of the emitting diode, normally 5 mA

T_j junction temperature (in Kelvin)

K_1 equals to 1, with 50% reduction of transfer factor at EOL

K_2 coefficient related to If, equals to 2.227 for I_f = 5 mA

K_3 equals to 0.4, with 15 defective units at EOL

4.3.5 EOL for microprocessors/controllers

For the ageing of microprocessors/controllers, the following equation is applicable:

$$L = L_0 \cdot e^{\left(\frac{E_a}{K} \cdot \left(\frac{1}{T_0} - \frac{1}{T_a}\right)\right)}$$

(Equation 4-11)

Where L EOL (time of data retention)

L_0 1000 hours, reference time of the test according to MIL STD 883 method 1008

E_a 0.7 eV activation energy

K 8.617 x 10^{-5} ev °C Boltzmann constant

T_0 temperature at L_o, equals to 150 °C + 273 = 423 (Kelvin)

T_a operating temperature (Kelvin)

4.3.6 EOL for output electromechanical relays

For electromechanical relays, the electrical EOL is normally measured by a number of daily operation cycles. In the case of output electromechanical relays in IEDs, the following is the number of maneuvers of their trip/close coils at different loads:

- 3. 10^5 maneuvers under 1 A resistive load
- 10^5 maneuvers under 8 A resistive load

Schneider Electric study shows that at ambient temperature in normal operation, the EOL of power transistors, ZnO varistors and opto-couplers is much longer than that for electrolytic capacitors and microprocessors/controllers. Meanwhile, in a normal scenario, the number of output electromechanical relays is limited (less than 100 times per day). It is suggested that in EOL estimation for digital relays, a utility rely on the calculated results from electrolytic capacitors and microprocessors/controllers.

This page is intentionally left blank.

5 INDUSTRIAL DATA ON DIGITAL RELAY EOL

There is limited industrial data available on digital relay EOL. As per the author, this phenomenon may be explained through the following reasons:

- Although introduced in the 1980's, digital relays had wide applications only after the mid 1990's. Due to its relatively short history compared with electromechanical relays and solid state relays, the statistical EOL information is limited.
- Due to the quick development in IT techniques, firmware and software upgrading is conducted at fast pace for the digital relays in operation. This changes the way data is processed and the way communication by the processors and memory units inside digital relays is conducted, thus affecting the operation environment (e.g. temperature). As a consequence, the EOL of such components (as can be seen in the previous section, one of the 2 components that have a shorter lifetime) is somewhat unpredictable.
- Utilities might have different ways in interpreting the EOL of digital relays. There is a common agreement regarding whether a digital relay reaches its EOL as long as it has to be sent to the manufacturer for repair/module replacement, or only when its major component (e.g. CPU rather than LED) requires a fix. In the latter case, extra effort is needed to track the root cause of the issue.

The following sections summarize the released digital relay lifetime data from both manufacturers and utilities.

5.1 Publications from manufacturers

In a normal case, it is difficult to obtain the lifetime data from the brochure or instruction manuals of digital relay manufacturers. For some manufacturers, they can provide reliability data regarding their digital relays, such as MTBF, etc. This data is, however, not of much help in determining the EOL. In fact it simply tells end-users how much of the total digital relay population might fail each year, before the EOL of a specific type of digital relay.

However, as in some cases, MTBF is expressed in years by manufacturers, so it is important to distinguish such “year” data from EOL year data.

An example might be: a digital relay manufacturer claims that its digital relays have MTBF = 100 years. This does not mean the relays can operate for 100 years on average, as the actual lifetime of digital relays is far shorter than that. It only means that its annual failure rate is 1% (1/100), or in any given 12-month period before the EOL, on average 1% of the whole population of such digital relays might fail.

Some manufacturers do provide a warranty period for their digital relays (e.g. 10 years). Although no one claims that this is the useful lifetime for digital relays, it does show that the manufacturers are confident that the failure rate within this period is low enough and under control, which in other words, implies that the EOL should be at least not shorter than it.

5.2 Publications from researchers and end users

According to the CIGRE study [35], for electromechanical relays, the mean EOL is around 30 years, with a standard deviation of 9 years. Digital relays will have a shorter EOL in comparison, due to the complexity and numerosity in its components.

Other study [36] suggests that 15 years is a reasonable value for the EOL of any electronic protection device.

5.3 Data records from Hydro One

GE and SEL digital relays are the main force in Hydro One substation protection. So far, there is no Hydro One statistical data on the EOL of these two types of digital relays. However, Hydro one receives reliability information regarding their digital relays from both GE and SEL.

As per the GE report in 2010 [22], all UR series digital relays have an MTBF = 150 years. This means that before the GE digital relays reach their EOL, every year 0.66% (1/150) of their population may fail, on average. There is no data on EOL.

As per the SEL report in 2010 [21], the SEL digital relays have an actual MTBF = 260 years. This means that before the SEL digital relays at Hydro One reach their EOL, every year, on average, 0.38% (1/260) of their population may fail based on the track record. There is no data on EOL, but a 10-year warranty period is offered.

In the above cases MTBF rather than MTTF data is provided. This means that the failures here may include scenarios which are reparable and of no major functionality issue. As mentioned in earlier chapters, MTTF rather than MTBF must be used when determining the EOL point on the Bath-tub failure rate curve.

This page is intentionally left blank.

6 CONCLUSIONS

The EOL of digital relays refers to the time when the failure rate of digital relays starts to escalate drastically. It indicates that on average, at such an age, digital relays will have major functionality failure that will lead to replacement of the relays.

The EOL of digital relays is determined by the ageing mechanisms of various components inside the digital relays. These mechanisms are mainly driven by thermal or electrical stresses, or a combination of both.

The estimation of the EOL of digital relays can be made using three different approaches: statistical analysis, a sample unit accelerating life test or model simulation. All three have their appropriate application depending on the actual data availability of the addressed digital relays.

In statistical analysis, the EOL of digital relays is determined based on historic failure records. This means that such an EOL is a representative value for the specific digital family on a specific utility site. The EOL here results from the combined commitment of various factors, including not only the relay components, but also the utility operation environment and operation modes. To work out the failure demography, utilities should only track the functionality failures that require major intervention, e.g. replacement by manufacturers. Minor fix or routine calibration should not be counted since these do not represent the intrinsic deterioration process inside the digital relays.

In the accelerating life test, the Arrhenius theory is applied to estimate the ageing process due to both thermal and electrical stresses. Based on the run-to-failure lifetime at a limited number of accelerated stresses, the lifetime at other stresses can be extrapolated. In this approach, the accuracy of the EOL estimation is very much dependent on the correct value of activation energy, which requires expertise and a profound understanding of the ageing mechanisms. There is more than one proposed model. The proper choice of model is also vital for EOL estimation, especially when there are both thermal and electrical stresses involved.

In model simulation, different formulas are developed for the major ageing components inside digital relays. Among the ageing components studied in this project, electrolytic capacitor and processor/memory chips have shorter lifetimes compared with the other components. In EOL estimation, utilities need to know operating temperature values, which might be either the ambient temperature or the temperature at some special locations in the circuits. Due to the limitations in obtaining the accurate temperature readings, it is suggested that this approach be adopted only if the other two approaches discussed above are not applicable.

The MTBF data provided by digital relay manufacturers does not indicate the EOL. This data is in fact mainly useful for reliability studies. The warranty period data, however, does provide some clue on the possible EOL of digital relays.

So far, there is not much EOL information published by industrial researches or studies. A commonly accepted point is that, in general, the EOL of digital relays is around 15 years.

7 RECOMMENDED APPROACHES FOR HYDRO ONE DIGITAL RELAYS

Based on the studies in the previous sections, it is recommended that for Hydro One digital relays:

1) In the short-term, when there are neither historic failure records nor sample accelerating life test results available, Hydro One could use 15 years as a generic EOL value for its digital relays.

2) If Hydro One has access to some detailed operating information, such as operating temperature as well as the manufacturer specified base lifetime for major components, Hydro One can estimate the EOLs at the component level using the formulas in section 4.3 and then use the shortest value as the EOL at the device level. To simplify the calculation, only an electrolytic capacitor in a power supply module and the processors in a CPU module need to be addressed in the calculation, as these two have shorter lifetimes in a normal case.

   This can be interpreted in an alternative way: if EOLs for different components are known, Hydro One can set up the routine maintenance/calibration test cycles based on such information.

3) In the mid-term, to better estimate the actual EOL for Hydro One digital relays, an accelerating life test is recommended. Hydro one must utilize a couple of sample digital relays that are representative of the entire population in terms of both functionality and operation. The accelerating life test is destructive as higher-than-normal thermal and electrical stresses are applied. The challenge in this approach is that Hydro One must determine the appropriate activation energy for the thermal process.

Although electrical stresses such as voltage, current and power do contribute to IED ageing, in practical testing it is found that thermal stress is the dominant ageing factor and applying thermal stress only can yield valuable results without sacrificing accuracy.

Activation energy is not generic and needs to be determined by experiments, though it is possible that different IED models might have similar activation energies for the same major components, thanks to a similar manufacturing technique. If no test data is available, one could use the standard activation energy data listed in [37].

Without any knowledge on a detailed model design, it is recommended that the ageing process for each model be conducted.

4) In the long-term, it is recommended that Hydro One estimate the EOL of its digital relays based on its own historic failure record. This requires that Hydro One start to collect such information on a routine basis and in a timely manner. Before such data collection, an internal agreement should be reached on the definition regarding major functionality failure of digital relays. After years and decades of tracking records, Hydro One can work out the failure demography for its digital relays. Such data can be useful in asset management and capital replacement for the asset group of digital relays.

   The minimum data requirement is: the survival percentages at 2 monitored age points of IED ages based on failure statistics. For example, if one estimates that the EOL of a specific IED is around 15 years, the survival percentages should be recorded at an age earlier than 15 years, as well as at an age later than 15 years. Starting from these two points, the failure rate curve can be interpolated.

   It is recommended that the information from manufacturers be broken down, e.g. GE vs SEL. Sub-categorization on the IEDs from the same manufacturer is not necessary, as presumably the same manufacturing process and techniques are applicable to all IEDs from the same manufacturer.

This page is intentionally left blank.

8 REFERENCES

1. IEEE Std 100-2000, Standard Dictionary of Electrical and Electronics Terms, New York, NY: IEEE

2. Military Handbook, "Reliability Prediction of Electronic Equipment", U.S. Department of Defense, Washington DC, MIL-HDBK-217F, 1991

3. D. J. Wilkins, "The Bathtub Curve and Product Failure Behavior: Part Two – Normal Life and wear-Out", Reliability HotWire, Issue 22, December 2002

4. European Power Supply Manufacturers Association, "Reliability – Guidelines to Understanding Reliability Prediction", EPSMA report, Edition 24, June 2005

5. M. Wiseman and D. Lin, "Reliability-Centered Knowledge Appendix 6", Optimal Maintenance Decisions (OMDEC) Inc.

6. S. Speaks, "Reliability and MTBF Overview", Vicor Reliability Engineering Inc report

7. H. Kameda and K. Yamashita, "Reliability Analysis for Protection Relays", 16th Power System Computation Conference (PSCC), Glasgow, Scotland, July 2008

8. J. Sharkey, "Protective Relays – Numerical Protective Relays", EPRI report, 2004

9. R. Kirby and R. Schwartz, "Microprocessor-based Protective Relays Deliver More Information and Superior Reliability with Lower Maintenance Costs", Schweitzer Engineering Laboratories Inc, 2009

10. E. Schweitzer III and P. Anderson, "Reliability Analysis of Transmission Protection Using Fault Tree Methods", Schweitzer Engineering Laboratories Inc, 1998

11. V. Gurevich, “Reliability of Microprocessor-based Protective Devices Revisited”, Journal of Electrical Engineering, Vol. 60, No. 5, 2009

12. V. Gurevich, “Reliability of Microprocessor-based Relay Protection Devices: Myths and Reality”, Serbian Journal of Electrical Engineering, Vol. 6, No. 1, May 2009.

13. J. Kumm et al., ”Assessing the effectiveness of self-tests and other monitoring means in protective relays”, PEA Relay Committee Spring Meeting, PA, May 1995

14. C. Heising et al., “Digital Relay Software Quality”, GE Power Management report

15. P. Montigies et al., “Digital Protective Relays Are Designed for Long Life”, 4th European Conference on Electrical and Instrumentation Applications in the Petroleum and Chemical Industry (PCIC Europe 2007), June 2007

16. D. Welton, “Testing Advanced Digital Relay Systems”, Electric Energy Online, 2011

17. H. Livingston, “SSB-1: Guidelines for Using Plastic Encapsulated Microcircuits and Semiconductors in Military, Aerospace and Other Rugged Applications”, G-12 Solid State device Committee of the Government Electronics & Information technology Association

18. S. Parler, “Deriving Life Multipliers for Electrolytic Capacitors”, IEEE Power Electronics Society Newsletter, Vol. 16, No. 1, Feb 2004, pp. 11-12

19. A. Albertsen, “Electrolytic Capacitor Lifetime Estimation”, Jianghai Europe GmbH report 2010

20. J. Benatti, “MTBF and Power Supply Reliability”, Astrodyne Corporation report

21. A. Fowler, “SEL Product Reliability Report for Hydro One”, Schweitzer Engineering Laboratories Inc, Apr, 2010

22. GE Digital Energy Multilin, “Product Reliability & Availability – UR”, Mar, 2010

23. W. Vigrass, “Calculation of Semiconductor Failure Rate”, Intersil Corporation report

24. Renesas Electronics Corporation, “Semiconductor Reliability Handbook”, 2008

25. International SEMATECH, “Semiconductor Reliability Failure Models”, 2000

26. M. White et al., “Product Reliability Trends, Derating Considerations and Failure Mechanisms with Scaled CMOS”, 2006 IEEE Integrated Reliability Workshop (IIRW), pp 156 – 159

27. J. Slama et al., “Study and Modelling of Optocouplers Ageing”, Journal of Automation & Systems Engineering”,

28. M. White and J. Bernstein, “Microelectronics Reliability: Physics-of-Failure Based Modeling and Lifetime Evaluation”, National Aeronautics and Space Administration, 2008

29. L. Escobar and W. Meeker, “A Review of Accelerated Test Models”, Statistical Science 2006, Vol. 21, No. 4, 552-577

30. T. Matsuda et al., “Experience with Maintenance and Improvement in Reliability of Microprocessor-Based Digital protection Equipment for Power Transmission Systems”, Report 34-104, CIGRE Session 30 August – 5 September 1992, Paris

31. A. Koert, “Accelerated Life Test – Programmable Auxiliary Logic Controller (PALC)”, Kinectrics Report No. k-418047-RA-0001-R00, Hydro One Report No. PR-90-027-R00

32. Envirotronics, “Stress Screening Systems – Rapid Temperature Change Rates for Environmental Stress Screening Applications”,

33. P. Vassiliou and A. Mettas, “Understanding Accelerated Life-Testing Analysis”, ReliaSoft Corporation, 2003 Annual Reliability and Maintainability Syposium

34. ReliaSoft Corporation, “Temperature-NonThermal Relationship”, 1998

35. CIGRE working group 37.27, “Ageing of the system impact on planning”, December 2000.

36. ElectraNet, *ElectraNet Consultance Services: Assessment of Asset Lives*, May 2007

37. IEC 61709:2010, Electronic components – Reliability – Reference conditions for failure rates and stress models for conversion, Ed 2.0, Committee Draft for Vote 56/1323/CDV, International Electrotechnical Commission.

GLOSSARY

Accelerated Life Test

A lab-based experimental method adopted for the quantitative prediction of a product's useful life. It expedites the ageing process of the product under testing by simulating higher than normal stress and usage, so as to fail the product within a substantially reduced service period.

Digital Relay

Also called a microprocessor-based relay or numerical relay. It refers to a microprocessor-based device that utilizes sampling techniques for input data processing and numerical algorithms for multi-function features of protection, control and data communication.

EOL

Abbreviation for End-of-Life. It refers to the time when the POF of a specific type of product reaches a limit expected by the end-user, i.e. when it is considered unable to physically perform its major functions as designed. It is case dependent and might appear during either the product's useful life period or wear-out period.

Failure Rate

Also called a hazard rate, instantaneous failure probability, or conditional failure rate. It refers to the POF at a specified time in a product's service life, with a condition that the product has not failed before that specified time.

IED

Abbreviation for Intelligent Electronic Device. It refers to a microprocessor-based device that performs electrical protection functions, advanced local control intelligence, has the ability to monitor processes and can communicate directly to a SCADA system.

MTBF

Abbreviation for Mean Time Between Failures. It refers to the average elapsed time between 2 consecutive failures, for the products that are to be repaired at failure and returned to service.

MTTF

Abbreviation for Mean Time To Failure. It refers to the average time for a device or component to run to failure. It applies to the products that are to be discarded at failure, or that require major overhaul and refurbishment.

POF

Abbreviation for Probability of Failure. It refers to the likelihood that, given the operating mode and failure mechanism, a product will fail to perform its major functionality before its in-service life reaches a specified length of time.

Useful Life

Also called service life. It refers to the time in a product’s service when the constant failure rate period is over and the wear-out failure period takes effect.

INDEX

A

accelerating life test .... *VI, VII, 24, 25, 26, 28, 41, 43*
activation energy.............................. *29, 32, 35, 41, 43*
ageing.... *VI, 2, 4, 11, 12, 17, 18, 19, 21, 24, 28, 29, 32, 33, 34, 41, 42, 51*
Analog/Digital input section *13*
Arrhenius *26, 27, 29, 41*

B

Bathtub Curve... *3, 47*

C

capacitors *12, 33, 35*

D

demography *41, 44*
digital relays..... *VI, VII, 1, 2, 12, 35, 37, 38, 39, 41, 42, 43, 44*

E

Electromigration *18*
EOL . *VI, VII, 1, 2, 3, 5, 6, 9, 19, 21, 22, 23, 24, 25, 26, 28, 32, 33, 34, 35, 37, 38, 39, 41, 42, 43, 44, 51*

F

failure rate .... *VI, 3, 4, 7, 8, 9, 22, 23, 31, 38, 41, 51, 52*
functionality.......................... *VI, 13, 21, 41, 43, 44, 52*

H

historic failure records .... *VI, 21, 41*
Hot carrier degradation *18*

I

IED 11
IEDs...... *I, 2, VI, 3, 5, 6, 7, 9, 11, 12, 19, 21, 28, 51*

L

long-term .... *VII, 26, 44*

M

mid-term... *VII, 43*
MTBF.................................. *1, 5, 38, 39, 42, 47, 48, 52*
MTTF *5, 7, 39, 52*

N

Network 1

O

operation environment.. *41*
Output section *11, 15*

P

Power supply section... *11, 17*
Probability of Failure
POF *52*
Processing section *11, 14*
processors.. *18, 37, 43*
microprocessors *4*

R

reliability *3, 5, 7, 27, 39, 42*

S

short-term .... *VII, 43*
stress level
stress *26, 27, 28, 30*

T

temperature.. *VII, 18, 19, 24, 29, 30, 33, 34, 35, 37, 42, 43*
thermal *4, 17, 18, 28, 29, 32, 41, 43*
Time-dependent dielectric breakdown *18, 19*

U

useful Life *52*

Ontario Energy Board (Board Staff) INTERROGATORY #048

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.3.3: Protection and Automation - Asset Assessment Details, Other Influencing Factors, pp. 28-29

"Technology Obsolescence – Many protection systems are no longer available, limiting the availability of spares and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid state systems."

Interrogatory:

Why is this a significant factor for electromechanical and solid state systems, but not for microprocessor based protection systems as well?

Response:

Electromechanical relays and solid state relays are no longer supported today as relay vendors are focusing their efforts on microprocessor based relays. Technology obsolescence is also a valid concern for microprocessor based relays. However, as this technology is in the midst of its development cycle, with wide range of manufacturers, fully supported in terms of technical expertise, spare parts, repair capabilities, and etc., microprocessor based relays are not considered technologically obsolete and we are readily able to deal with microprocessor relays failures.

Microprocessor based relays have all protection functions fully programmable within a single unit. Such a relay has a significantly smaller form factor with a modular design adhering to industry standards. Protection setting modification as well as replacement of microprocessor based protections has less impact on outage planning and overall system reliability compared to electromechanical and solid state systems.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #049

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.3.3: Protection and Automation - Asset Assessment Details, Other Influencing Factors, pg. 29

"Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. Modern microprocessor protection systems can be deployed with pre-tested configuration settings to facilitate fast and efficient system protection changes to accommodate dynamic changes to the configuration of the transmission system. Extended maintenance intervals for microprocessor based systems help contain OM&A expenditures and reduce life cycle costs."

Interrogatory:

Please reconcile the above statement with Hydro One's claim on page 27 that microprocessor based protections are a relatively new technology, and that detailed condition metrics and indicators are not as well established. In addition, it appears that that the expected life of microprocessor based protection systems is much shorter than the other two protection technology types.

Response:

A Microprocessor based relay has the capability to capture voltage and current waveforms allowing system transients to be monitored and the amount of energy to be measured for individual station equipment. This information helps to provide insight into a station's power equipment performance and allows for early detection of problems with breakers, transformers, capacitors, reactors, etc.

In terms of condition metrics for microprocessor itself, it is not well established due to the complexity all of the electronic components it is composed of. However, since microprocessor relays have some degree of self-monitoring failed or suspect relays can be identified immediately rather than be discovered during routine maintenance or during system events. Microprocessor based relay issues are often communicated by the relay manufacturer prompting remedial investigation and action.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #050

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 3.1.1: Transmission Overhead Conductor and Hardware - Asset Overview, pg. 31; Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Demographics, pg. 33

"9% of the conductor population falls within the high risk category. Hydro One expects population of this category to increase as additional condition assessment programs are carried out during the test years.

The number of forced outage from conductors has declined slightly in recent years while the duration of outages has remained flat."

"Although there have been recent increases in replacement rates to deal with immediate risks, Figure 21 demonstrates that by 2025 the number of conductors beyond their expected service life will increase by over 90%. Hence an increase in future replacements is required to maintain acceptable fleet demographics."

Interrogatory:

a) Please reconcile the two statements cited in the excerpts from Section 3.1.1 above; if 9% of the conductor population falls within the high-risk category and that percentage is continually increasing, why is performance improving?

b) Has Hydro One tracked conductor failures by age of asset? If so, please provide this information.

c) What are the primary modes and relative frequencies of actual conductor failure, in comparison with the failure modes and frequencies of items such as conductor suspension and splicing hardware?

Response:

a) The poor condition of transmission conductors does not directly translate to outage frequency and duration. Please refer to Exhibit I, Tab 1, Schedule 22, Part d) for a detailed explanation.

b) Please refer to Exhibit I, Tab 1, Schedule 22, Part d).

Witness: Chong Kiat Ng

c) The primary failure mode for conductors is mechanical only. Conductor failures are mainly due to the loss of metal caused by corrosion, resulting in a loss of tensile strength and/or loss of torsional ductility which can result in breakage of the conductor when subjected to external factors such as extreme weather condition or tree contacts. Additional information is available in Exhibit I, Tab 1, Schedule 22, Part d).

Ontario Energy Board (Board Staff) INTERROGATORY #051

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 3.1.2: Transmission Overhead Conductor and Hardware – Asset Strategy, pg. 31

"Hydro One intends to replace approximately 0.6% of conductor in 2017 and 1.5% in 2018, in order to manage risks associated with the declining condition of the conductor population."

Interrogatory:

Exhibit B1, Tab 2, Schedule 4, Figure 5 shows approximately 3000 circuit kms of anticipated conductor sustainment work volume in 2018. Please reconcile the anticipated conductor work volumes shown in Figure 5 with the replacement values provided in the cited excerpt from Section 3.1.2.

Response:

Exhibit B1, Tab 2, Schedule 4, Figure 5 shows the potential conductor replacement needs based on age demographics and average life expectancy for conductors. Hydro One proposed conductor replacement plans are based on confirmed laboratory condition tests, on those circuits that have been assessed, as Hydro One does not replace conductors based on age only. Figure 24 in Exhibit B1, Tab 2, Schedule 6 provides information regarding condition assessment for conductors.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #052

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Demographics, pg. 32

"Hydro One uses an expected service life ("ESL") of 70 years for conductors; although this can vary based on several factors, with environmental conditions being the primary factor."

Interrogatory:

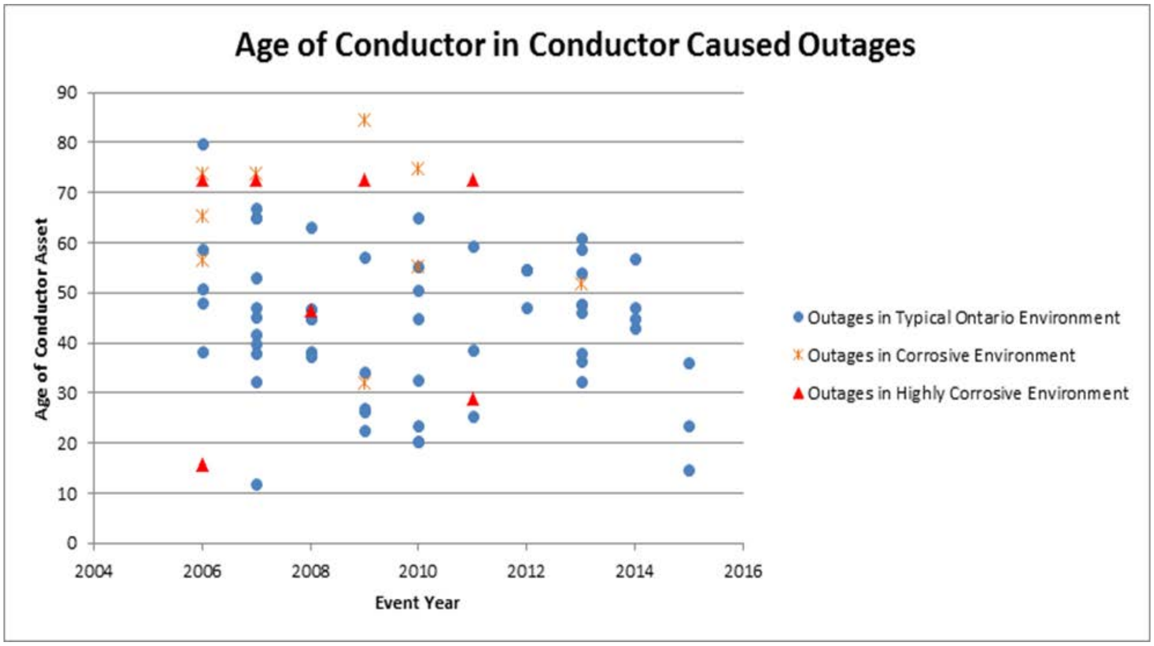
a) Please quantify the relationship between the different environmental conditions evaluated by Hydro One and the impact on conductor ESL.

b) Please provide any analysis conducted by Hydro One that correlates conductor age in regions exhibiting these different environmental conditions with the frequency of outages caused by conductor failure.

Response:

a) Hydro One has recently conducted an environmental condition correlation study for conductor ESL. As part of this study end of life conductors verified by laboratory tests were mapped into various corrosion zones in Ontario. The result of the correlation study was not conclusive. As explained in Exhibit B1, Tab 2, Schedule 6, page 36, there are many influencing factors contributing to actual service life of a conductor.

b)


Age of Conductor in Conductor Caused Outages
Age of Conductor Asset
Event Year
Outages in Typical Ontario Environment
Outages in Corrosive Environment
Outages in Highly Corrosive Environment

Ontario Energy Board (Board Staff) INTERROGATORY #053

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Performance, Figure 22 – Forced Outage due to Conductor & related Hardware Failures, pp. 33-35

"The number of forced outages due to conductor failures has improved over the past 10 years, as outlined in Figure 22.Outage frequency and duration performance is anticipated to deteriorate based on the results of condition assessment derived from actual aged conductor sample testing."

Interrogatory:

a) Please reconcile the above statement that forced outages due to conductor failures have improved over the past 10 years with Hydro One's claim that an aggressive conductor replacement program (e.g.: 3000 circuit kms of anticipated conductor sustainment work volume in 2018) must be implemented in the Test Years and forecast years to mitigate material future increases in conductor failure frequency.

b) Please explain the results shown in Figure 22 given Hydro One's aging conductor fleet demographics.

Response:

a) For above questions, please refer to the answer provided in Exhibit I, Tab 1, Schedule 22, Part d).

b) Figure 22 provides statistics concerning conductor outage frequency. A line drop (conductor failure) is a low probability but high consequence event, which depends on two factors; condition of the conductor which Hydro One can control and adverse environmental condition which Hydro One cannot control. Therefore, Hydro One aims to mitigate this safety risk by proactively identifying end of life conductors through condition assessments, and then replacing these conductors in order to maintain reliability. The increasing end of life conductor demographic results in deteriorated condition, requiring increased levels of replacement.

Ontario Energy Board (Board Staff) INTERROGATORY #054

Reference:

Exhibit B1/Tab2/Sch6/ – Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Performance, Figure 23 – Forced Outage Duration due to Conductor Failure, pg. 34

"The forced outage duration due to conductor failure, displayed in Figure 23, demonstrates that conductor outage duration has been relatively stable over the last 10 years with the exception of the abnormality in 2009 and 2015."

Interrogatory:

Please explain in detail the causes of the apparently abnormal conductor outage durations in 2009 and 2015.

Response:

The abnormal outage duration in 2009 is mainly due to near conductor failures on circuits B10 and B20H. The conductors were in such poor condition that upon a detailed helicopter inspection the circuits were forced out of service under emergency due to public safety concerns. It took several weeks before these conductors could be replaced.

The abnormal outage duration in 2015 is mainly due to down conductors on railway tracks and a municipal road on the A6R. This required extensive coordination with the railway company and other organizations such as Ottawa Hydro and Transalta Cogen to restore the circuit.

Ontario Energy Board (Board Staff) INTERROGATORY #055

Reference:

Exhibit B1/Tab2/Sch6/ and Exhibit B1/Tab3/Sch2
Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Demographics, Figure 35 – Projection of Steel Structures Requiring Coating, pp. 49-50 and Section 5.2.2: Investment Plan, Table 16 – Overhead Lines Component Replacement Programs ($ Millions), pg. 35

"Based on the historical data, the average rate for structure renewal is about 200 towers per year. As outlined in Figure 35, at historic tower coating rates, the steel structures requiring coating in high corrosion zones will increase by 34% in 10 years. However, with planned coating plan, all structures requiring coating will be coated in the next 10 years."

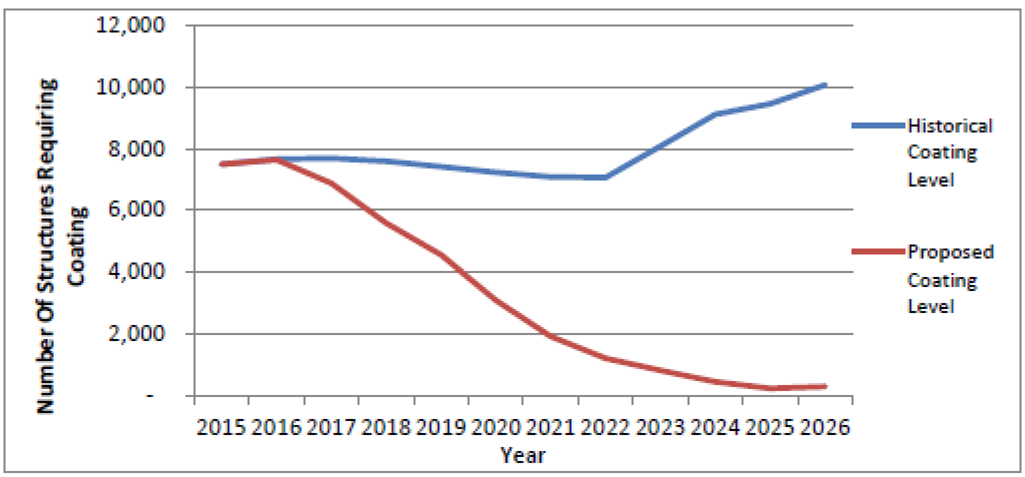


Figure 35: Projection of Steel Structures requiring Coating

Table 16: Overhead Lines Component Replacement Programs ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Wood Pole Replacements	26.9	32.7	43.6	38.5	38.3	35.3	35.3
Steel Structure Coating	1.6	5.7	5.1	4.6	8.8	42.5	54.4
Steel Structure Foundation Refurbishments	3.3	4.5	3.6	1.6	3.9	7.8	7.8
Shieldwire Replacements	4.4	2.9	8.2	4.3	5.2	7.0	7.1
Insulator Replacements	3.3	6.9	3.8	2.8	26.1	63.9	61.4
Transmission Lines Emergency Restoration	8.0	8.2	8.7	8.8	8.3	8.7	8.8
Other Line Component Replacements	3.4	5.6	5.7	6.0	3.2	5.0	5.2
Total	**50.9**	**66.5**	**78.7**	**66.6**	**93.8**	**170.2**	**180.0**

Interrogatory:

a) Please show the expected rate of failure if the steel structure re-coating rate is maintained at the present rate rather than being increased by 34%.

b) Please provide a quantified rationale for the increase in Steel Structure Coating program investments in 2017 and 2018 relative to historic years. What, if any, change does this increased level of investment indicate in Hydro One's Steel Structure Coating sustaining capital investment philosophy?

c) Please provide a quantified rationale for doubling Steel Structure Foundation Refurbishment investments in 2017 and 2018 relative to historic years? What, if any, change does this increased level of investment indicate in Hydro One's Steel Structure Foundation sustaining capital investment philosophy?

d) Please provide a quantified rationale for the increased Insulator Replacements in 2017 and 2018 relative to historic years. What, if any, change does this increased level of investment indicate in Hydro One's Insulator Replacement sustaining capital investment philosophy?

e) Regarding "Other Line Component Replacements" investments, if the potential costs associated with emergency restoration are unpredictable, please explain how Hydro One selected investment values of $3.2M in 2016, $5.0M in 2017, and $5.2M in 2018?

Response:

a) The main objective of structure coating program is to extend the life of steel structures in the most economical way. Structure coating program is not intended to prevent immediate structure failures. The rate of failure for structures is dependent on the condition of the structures and the impact of adverse environmental factors which is not predictable, such as wind and ice. If structures are not coated at the optimum time, they will require more expensive mitigation measures such as structure member replacement or even complete structure replacement. Therefore, structure coating is a cost effective alternative approach to replacement, as further explained in part (b) below.

b) In the past 10 years, Hydro One's structure coating program was significantly below the required levels to preserve the condition of these assets. Hydro One's structure coating philosophy has not changed. This was due to safety and work method constraints. The average recoating cost of the steel structures identified for the test years is approximately \$34k per structure. The first structure coating typically needs to occur when the structure is approximately 60 years old and again every 30 to 40 years thereafter. However the cost of replacing a steel structure is approximately \$250k to \$350k, depending on the type of structure. Even with repeated coatings, the life of the steel structures can be extended indefinitely achieving a significant savings. Hydro One has estimated the present value savings of structure coating (over structure replacement) for 115 kV and 230 KV structures to be approximately \$62K and \$65K respectively.

c) The steel structure foundation refurbishment program is intended to assess, repair or replace the problematic steel structure foundations and mitigate the risk of foundation failure. Based on current available information, there are still approximately 16,000 steel structures requiring foundation assessment. The inspection reports from recent line refurbishment program show that the number of failed foundations is increasing and those failed foundations must be replaced with significantly higher cost than to inspect, clean and coat them in a timely manner. One example of excessive foundation deterioration is the D2L line refurbishment project. Hydro One anticipated approximately 20 to 30 of the foundations will require replacement, but the actual number exceeds 52 after inspecting the foundations. There is no change in Hydro One's Steel Structure Foundation sustaining capital investment philosophy, which is to arrest foundation deterioration before failure occurs.

d) Hydro One has asked Electrical Power Research Institute (EPRI) to conduct an independent evaluation of current condition of these defective insulators. The result of this investigation confirms that many tested insulators did not meet the standard electrical mechanical tests. In

March 2015, the centre phase insulator on V76R failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. This type of failure represents a public safety risk. As a result, in 2016 Hydro One implemented an accelerated insulator replacement strategy which aims to address this public safety risk. Please refer to Exhibit I, Tab 1, Schedule 106, Part a), Subsection i) for more information.

e) “Other Line Component Replacements” and “Transmission Lines Emergency Restoration” are two separate line items in table 16. Hydro One selected investment values of $3.2M in 2016, $5.0M in 2017, and $5.2M in 2018 are for the other line component replacements, which are separate from emergency restoration. Other line component replacement are selected and forecasted based on condition assessments.

Ontario Energy Board (Board Staff) INTERROGATORY #056

Reference:

Exhibit B1/Tab2/Sch 7 – Section 1: Introduction, pg. 1

"The investment planning process draws upon the previous year's efforts to identify investment needs, evaluating and prioritizing proposed individual investments that address these needs, based on the business objectives. The end product is a fully prioritized investment plan."

Interrogatory:

a) Please confirm that the list of "investment needs" projects carries over from year to year until all identified projects are refurbished or replaced.

b) Have Hydro One's business objectives changed from year to year or from filing to filing? Is it accurate to say that the prioritization of projects taken from the investment needs list would be very similar regardless of Hydro One's business objectives?

Response:

a) Yes, the previous, and remaining, investment needs are part of the information included in each year's investment planning process. Additionally, new information is included, particularly with respect to Development investments which are largely influenced by factors external to Hydro One, such as load/generation connection requests/forecasts and broader regional planning considerations.

b) Hydro One's business objectives have not materially changed from year-to-year or from filing-to-filing. It is not accurate to say that the prioritization of projects would be similar regardless of Hydro One's business objectives. Depending on the magnitude of change to the business objectives and the relative importance placed upon each objective, the prioritization of projects could change.

Ontario Energy Board (Board Staff) INTERROGATORY #057

Reference:

Exhibit B1/Tab2/Sch 7 – Section 2: Strategic Context, pg. 2

"The business drivers are assigned weights by Hydro One's investment management group, based on their relative importance to the company."

Interrogatory:

Please provide concrete examples of the set of risk-based and outcome-based factors that Hydro One employed in assigning weights to the business drivers.

Response:

Hydro One's business objectives are *measured* by a set of risk-based and outcome-based factors, as shown in Table 1 of Exhibit B1, Tab 2, Schedule 7. However, these factors can impact the weighting assigned to a business driver. For example the weighting assigned to the business driver "Customer Focus" was increased in 2014 to reflect Hydro One's desire to improve the outcome-based factor of "Customer Satisfaction."

Ontario Energy Board (Board Staff) INTERROGATORY #058

Reference:

Exhibit B1/Tab2/Sch 7 – Section 3: Economic Assumptions, pg. 3

"An economic outlook and customer load forecast are developed and used as basic assumptions in developing the investments. The load forecast is discussed in Exhibit E1, Tab 3, Schedule 1."

Interrogatory:

a) How does economic outlook impact decisions on sustaining capital, operations, and common corporate costs? Specifically, why does economic outlook, customer load forecasts and business objectives alter forecasts of non-discretionary items such as sustaining capital and operations which are based primarily on assets already in the ground?

b) Are the assumptions within the economic outlook identical to the assumptions that are taken into account when undertaking the various Regional Plans?

c) How does Hydro One differentiate between non-discretionary investments and discretionary investments to ensure that only those projects that represent truly non-discretionary investments are identified before prioritizing discretionary spending? Please provide examples of the most common investment types that Hydro One categorizes as discretionary and non-discretionary.

Response:

a) The economic outlook affects investment decisions. The economic indicators for construction costs, CPI and exchange rate directly affect the cost estimates of work. For example, approximately 25% of capital spending on transport and work equipment is conducted in U.S. dollars.

To address the specific request, the key objectives of non-discretionary Sustainment capital is to maintain the safe and reliable transmission of electricity to all customers within Ontario and to address the needs of customers and the broader transmission system. There is often a correlation between customer load forecasts and economic outlook, as seen in the Hamilton and Niagara regions over the last 15 years. Both regions have experienced a reduction in customer demand. While focused on the currently installed asset base, Sustainment capital investments are developed to mitigate reliability risk and meet customer needs and preferences as detailed in Exhibit B1, Tab 3, Schedule 2 which are driven by customer load forecasts and the economic outlook. Using the Hamilton and Niagara regions as examples, it would not be fiscally prudent to replace all assets in a 'like-for-like' manner as the customer needs and forecasts have evolved, primarily with the reduction in industrial customers. Non-discretionary Sustainment capital investments would therefore be modified to be in line with the evolving customer needs. For example, transmission facilities could be eliminated, consolidated, or reconfigured to better suit connected customers in a more fiscally prudent manner.

b) No, the assumptions are different. The load forecast assumptions for regional plans are different as they are developed for a different purpose. The forecast for regional planning is intended to identify capacity issues at a regional or sub-regional level rather than at a provincial level and reflect local economic conditions.

c) Hydro One differentiates between discretionary and non-discretionary investments on the basis of whether the investment need is beyond the control of the company. Where the investment need is beyond the control of Hydro One, the investment is classified as non-discretionary. Non-discretionary investments are driven by requirements to satisfy legal and regulatory obligations; connect new generation; address equipment condition, loading or voltage/short circuit stresses; and address needs identified in system and regional plans. To ensure investments are suitably aligned to this classification during the investment prioritization process, a multi-level review is undertaken to guard against inconsistencies.

Common types of non-discretionary investments include like-for-like equipment replacements, investments to comply with NERC cyber security standards, and new load/generation customer connection requests.

Discretionary investments enhance the transmission system beyond a minimum standard such as increasing reliability and adding flexibility to the operation and maintenance of the transmission system. Examples of discretionary investments previously planned, but subsequently deferred, include enhancements to telecommunications operating infrastructure.

Ontario Energy Board (Board Staff) INTERROGATORY #059

Reference:

Exhibit B1/Tab2/Sch 7 – Section 4.4: Risk Treatment and Options Analysis, pg. 14

"These identified options and flexible timing arrangements are, at least in the short term, considered to be viable candidate investments, and are included in the optimization process for potential selection."

Interrogatory:

Are the risk ratings given for the various scenarios based upon subjective judgment?

a) If yes, how does Hydro One guard against judgment bias that may be contrary to objective evidence?

b) If no, please provide the methodology for determining the quantitative risk ratings based on objective evidence.

Response:

a) Risk ratings of candidate investments reflect the exercise of professional judgment based on the application of a defined risk matrix to objective evidence as described in Exhibit B1, Tab 2, Schedule 7. Objective evidence varies depending on the nature of the investment area and availability of supporting data.

   To guard against judgment bias, Hydro One has developed training modules to drive a consistent assessment of risk across business units, guiding planners to identify the risk sources (hazards or threats) and the strength of existing controls and, ultimately, to define the risk event that the investment is intended to mitigate or prevent, as outlined in section 4.3 of Exhibit B1, Tab 2, Schedule 7.

   As described in section 4.5 of the same Exhibit, Hydro One employs a multi-level managerial review during the investment development process. The initial managerial review is focused on the investment justification and the reasonableness of the investment's risk and value assessment. These initial reviews aim to ensure risk ratings within an investment area are reasonable.

In an effort to continuously improve its investment planning process, for the next cycle of investment planning, Hydro One has implemented an additional control factor: a cross-functional peer review session. This review focuses on cross-business unit calibration of risk assessments to ensure that risk is not being understated or overstated. The process allows investments to be compared on a risk value basis across different business units in the prioritization and risk optimization process. Business units are incented to scrutinize their peers, ensure that risk assessments are appropriately calibrated, and that the resulting optimized investment portfolio adequately reflects Hydro One's priorities.

b) See above.

Ontario Energy Board (Board Staff) INTERROGATORY #060

Reference:

Exhibit B1/Tab2/Sch 7 – Section 6.2: Re-direction of Funds, pg. 17

"The re-direction of funds allows appropriate and prudent adjustments to be made to the work originally identified in the investment plan. As an example, the emergency restoration work needed to repair equipment failures or storm damage to a transmission line can be significant. Such events may necessitate the re-direction of funds and field resources from other investment areas."

Interrogatory:

a) What percentage of overall capital funds have been redirected from the investment plans in each year, from 2012 to 2015? Please identify the recipient and donor investment categories to and from which the funds were transferred, respectively, along with the rationale for the transfer.

b) For each project originally identified in the original investment plan but not executed as planned, please identify the rationale for re-directing funds to another project.

Response:

a) Between 2012 and 2015, redirection was not required to stay within the approved capital envelope as Hydro One underspent its capital budget.

b) Hydro One has project governance for variances that requires documentation and approval of material variances. The cost materiality threshold set by the governance structure is a forecasted cost increase of either: (a) more than 10% of currently approved funding and greater than $500,000; or (b) a variance greater than $2,000,000. There are also variances for scope changes or schedule changes, which are subject to the same governance structure, but with different thresholds. Below is a list of all projects, from 2012 to 2015 that met the materiality threshold in any combination of scope change, cost change or schedule change.

Project Name	**Variance Type**	**Result of**
Telematics	Schedule variance	Changing asset priorities based on new information
OMA Enterprise Content Management ECM	scope variance and Schedule variance	Changing customer needs and requirements

Witness: Mike Penstone

Project Name	Variance Type	Result of
Enhanced Asset Management Analytics (AA)	scope variance and cost increase	Changing asset priorities based on new information
IT Business Solutions Development SAP GIS Integration Project	Schedule variance and cost increase and scope variance	Changing asset priorities based on new information
customer Operations Mobile Phase 2B	Schedule variance and cost increase	Changing asset priorities based on new information
Domtar Green Transformation Generation Project (DC LINK)	Schedule variance and cost increase and scope variance	Changing external requirements
Terry Fox MTS Build New 230kV Line Tap	Schedule variance and cost increase	Changing customer needs and requirements
Lower Mattagami Generation Connections	Schedule variance and cost increase and scope variance	Undervalued estimate and scope increase
Leaside x Bridgman Transmission Expansion Project	Schedule variance and cost increase	Major unforeseen events
Lambton TS station Upgrade	Schedule variance and cost increase and scope variance	Changing customer needs and requirements
Port Arthur TS No 1 Install Series Reactors	Schedule variance and cost increase and scope variance	Unforeseen delay and cost increase in project component
H7L and H11L Mitigate 115kV Overvoltages Main TS Install 2 115kV Cct Breakers	Schedule variance and cost increase	Undervalued estimate
NetScaler Replacement Project	Schedule variance and cost increase and scope variance	Changing external requirements
H7L and H11L Mitigate 115kV Overvoltages	scope variance and cost increase	Undervalued estimate and scope increase
Uprate Short Circuit Capability of 15 115kV Breakers at Allanburg TS	Schedule variance and cost increase	Changing asset priorities based on new information
Manby TS Uprate 115 kV Station Short Circuit Capability	Schedule variance and cost increase	Undervalued estimate
Lambton TS Station Upgrade	Schedule variance and cost increase and scope variance	Changing asset priorities based on new information

Project Name	**Variance Type**	**Result of**
Basin TS 115kV Shunt Reactors and Arresters	Schedule variance and scope variance and cost increase	Undervalued estimate and scope increase, unforeseen delay in project component
Extreme Space Weather Readiness	Schedule variance and cost increase and scope variance	Changing customer needs and requirements
Crystal Falls SS Bulk	Schedule variance and cost increase and scope variance	Changing external requirements
D9H_D10S Line Refurbishment	Cost increase	Undervalued estimate
Kent TS DESN 1 Feeder M15 DG 274 Distance Limitation	Schedule variance and cost increase	Undervalued estimate
Orangeville TS Breaker Replacement	Schedule variance and cost increase	Undervalued estimate and scope increase
London Nelson TS EOL Replacement	Cost decrease and scope variance	Changing customer needs and requirements
Class EA Process Update	Cost decrease and schedule variance	Changing external requirements
Bridgman TS PCT Equipment Replacement	Scope variance and cost increase	Changing customer needs and requirements and changing external requirements
Hanmer TS Transmission Station Re Investment Project	Schedule variance and cost increase	Major unforeseen events
BSPS Replacement of End of Life Equipment Project	Schedule variance and cost increase and scope variance	Changing external requirements
Red Rock to Nipigon Hwy 11 17	Cost decrease and schedule variance	Scope decrease
2004 Monitoring Bruce GS add SER and Decommission (Bruce A and B RTUs)	Schedule variance and cost increase	Unforeseen delay and cost increase in project component
St Lawrence x Moses NYPA Tie Line Protection Replacement L33P and L34P	Schedule variance and cost increase and scope variance	Changing external requirements

Ontario Energy Board (Board Staff) INTERROGATORY #061

Reference:

Exhibit B1/Tab3/Sch 1 – Section 2.4: Common Corporate Capital, pg. 5

"Common Corporate capital spending levels in the test years are forecast to be higher than historical levels due to: (a) higher capital spending on information technology development projects, which aim to improve productivity in Hydro One's operations; (b) increased facility needs for expanding Sustainment, Development and Operations work programs; and (c) incremental capital investments in transport and work equipment, primarily, a new helicopter. The capital spending levels are forecast to be relatively stable through the test years."

Interrogatory:

Please provide the business case for the decision to acquire a new helicopter rather than pursue other alternative options (e.g., drones, subcontracting, etc.).

Response:

Please see Exhibit B1, Tab 3, Schedule 11 - #CC2 (Investment Summary Document – Transport & Work Equipment), which describes the capital replacement requirements for fleet vehicles. Hydro One does not treat helicopters differently from other fleet investments.

Historically, and in keeping with industry standards, Hydro One has replaced helicopter equipment on a 15-year service or 10,000 flight hour life cycle. Currently, Hydro One has three machines past these milestones. The benefits of buying a new helicopter include improved safety, vehicular efficiency, reduced maintenance costs, manufacturer's warranties, and extending the time before component parts need to be overhauled.

The purchase of a new helicopter is needed to meet Hydro One's long-term program requirements, which cannot be met with Hydro One's current eight aircraft. Over time, Hydro One has increased its use of helicopters for construction, refurbishing, and sling work as well the transportation of people and equipment, and decreased use for patrolling and reconnaissance purposes. Over the past five years, work in Hydro One's lines, forestry, and construction organizations has increased significantly as has their helicopter usage due to the operational efficiencies offered by helicopters.

Hydro One's shield-wire bonding work demonstrates the efficiencies gained by helicopter use. For work spanning Thunder Bay to Marathon, conventional methods were estimated to take three years, large crew numbers and approximately three million dollars to complete. With the use of one helicopter and two regional line maintainers, Hydro One completed this work within seven weeks for less than one million dollars. Use of helicopters decreases travel time for work crews and has minimal environmental impact compared to road transport, which involves road construction, bridge building, crop damage and environmental assessments. Time and cost savings are also associated with avoiding these activities.

Hydro One uses helicopters for higher risk, specialized work, such as aerial platforms, aerial construction in energized environments, mid-span conductor and shield-wire repairs, storm thermo-vision patrols to identify and prevent unplanned outages, transport to and from transmission and distribution corridors, storm restoration and trouble calls. Subcontractors are used for overflow lower risk helicopter work when internal resources are occupied. In the last several years, subcontracted helicopter work has increased significantly as internal resource utilization is at capacity.

The use of drones is still in early stages. Currently Hydro One has eight unmanned aerial vehicles, which it uses in for the following applications: structure inspection, storm response management, area/asset inspection, determining access points, and 3D mapping.

Ontario Energy Board (Board Staff) INTERROGATORY #062

Reference:

Exhibit B1/Tab3/Sch 1/ Attachment 1 – Comparison of Net Capital Expenditures by Major Category – Historic, Bridge and Test Years, pg. 1-3

Interrogatory:

a) What is the benefit to ratepayers of Hydro One's decision to change practice between 2012-2013 and 2017-2018 and group most substation spending into Integrated Station Investments? Please provide quantified evidence of the benefit to ratepayers.

b) Hydro One claims in Exhibit B1/Tab3/Sch2 – Section 3.3 that one of the benefits of Integrated Capital Investments is cost avoidance, thereby resulting in reduced overall capital expenditures. Please reconcile this claim with the forecast investment increase in Transmission Stations Capital from $322.5 million in 2012 to an annual average in excess of $500 million for the years 2014 to 2018.

c) What is the rationale for increasing the level of overhead lines investments by a factor of 5 from 2012 to 2018 despite acceptable line performance statistics? Please explain in detail.

d) What is the rationale for the order of magnitude step increase in underground cable refurbishment and replacement investment levels from 2017 to 2018?

e) Overall Sustaining Capital investments are forecast to increase from less than $400 million per year in 2012 to over $800 million per year in 2018. Please provide a cost-benefit analysis to justify more than doubling the level of Sustaining Capital Investments over this period.

Response:

a) Please refer to Exhibit B1, Tab 3, Schedule 2, Section 3.3 for details relating to the quantified benefits from Integrated Station Investments. This approach enables delivery of a large volume of investments driven by asset needs to maintain top quartile reliability and addresses customers' needs and preferences. A few examples of these are:

   i) Wanstead TS (ISD-S17): Reduction of transformers from 3 to 2 units, standardization of design for operational efficiency, and reconfiguration to dual supply from 230kV connection to meet customer needs for improved reliability.

ii) Nelson TS (ISD-S15): Reduction of transformer from 4 to 2 units for operational efficiency, and upgrading of distribution voltage to 27.6kV to meet customer's needs.

iii) Aylmer TS (ISD-S20): Standardization of design to improve operation efficiency, replacing outdoor switchyard with medium voltage gas insulated switchgear to improve reliability and adding new feeder positions to meet customer's needs.

b) The saving from cost avoidance to reduce overall capital expenditure stems from reduction in asset footprint such as reducing 4 transformers to 2 transformers, or reconfiguring a switchyard to eliminate breakers. The increase in Transmission Station Capital is a result of undertaking a larger investment portfolio to maintain reliability performance. The level of investment is correlated to the large, aging and deteriorating asset fleet managed by Hydro One. Exhibit B2, Tab 2, Schedule 1 describes the Total Cost Benchmarking study that supports capital expenditure needs to increase to maintain reliability.

c) Due to historic low level of investment in this area, aging demographics and emerging information about asset conditions, such an increase in capital expenditure is needed to ensure safety, maintain reliability and extend asset life:

i) A sizeable subset of Hydro One's installed suspension insulators is deemed to be in poor condition due to a manufacturing defect. The urgency of this problem came to light upon completion of an Asset Event Investigation as a result of an impactive line drop incident in 2015. When these insulators fail and separate, the conductor will drop to ground, which is both a safety and reliability concern. An increase in investment to accelerate replacement program is a necessary step to ensure safety and reliability. ISD-S79 describes this investment in detail.

ii) Nineteen percent (19%) of Hydro One's conductor fleet is currently beyond ESL. Based on historic rate of replacement, by 2025 the subset of conductor operating beyond ESL will almost double. In order to maintain safety and reliability, minimize reliability risk and allow for a manageable execution pace, it is necessary to increase the conductor replacement rate. The conductors selected for line refurbishment investments are supported by actual conductor sample testing results to verify either at or near end of life conditions. When a conductor arrives at or is near end of life condition, it would have low remaining strength and low ductility, resulting in an increased probability of failure. ISD from S62 through S74 describe these investments.

iii) A subset of Hydro One transmission line structures requires application of zinc-based coating to extend life. A new steel structure comes with a layer of galvanized zinc to protect itself against corrosion. As this protective layer wears off over time, bare carbon steel is exposed to the atmosphere and corrodes at an increased rate. Corrosion erodes structural integrity, which leads to safety and reliability concerns. The eventual outcome of structure corrosion is costly structure replacement. Application of a zinc-based coating is an efficient and cost effective approach to extend asset life. (See Board Staff IR #55) ISD-S76 provides details of this investment.

Hydro One is observing a large portion of SAIDI that in recent years is attributed to line related failures. These failures contributed to 69% of Hydro One's total interruption minutes from 2011-2015 (see Exhibit B1, Tab 2, Schedule 2, Attachment 2, page 13). When a conductor has deteriorated to, or near end of life condition as verified by laboratory testing, it cannot be relied upon to operate in a safe and reliable manner. It will break under adverse weather loading conditions, which is a risk to safety and reliability. While historical performance has been acceptable, SAIDI and SAIFI or other lagging indicators are not indicative of future performance. In contrast, asset condition is indicating performance is likely to worsen in the future. Hydro One is therefore proposing to increase capital expenditure to maintain safety and reliability.

d) The reason for this step increase is H7L/H11L Cable Replacement project (ISD-S83). The project execution schedule requires $1.3M and $21.1M to be spent in 2017 and 2018 respectively.

e) The increase from $400 million per year in 2012 to over $800 million per year in 2018 is driven by asset needs to ensure safety and maintain reliability performance which is supported by Exhibit B2, Tab 2, Schedule 1, Total Cost Benchmarking Study. Cost benefit analysis is completed as part of the business case approval process of the individual projects which comprise the Sustainment capital investments.

Ontario Energy Board (Board Staff) INTERROGATORY #063

Reference:

Exhibit B1/Tab3/Sch 2/– Section 3.2: Fundamentals of Integrated Investments, pg. 5

"The three year window aligns with the typical three to five year project execution duration required for scope development, design, construction and commissioning of integrated investments projects. This approach minimizes the potential for repeated mobilization of work crews to replace individual assets. Assets that are not in need of replacement or refurbishment are maintained until the next investment cycle when they are reassessed.

This approach provides opportunities to reduce the number of assets through reconfiguration, utilize modern technology and implement safety by design, to improve reliability, safety and productivity."

Interrogatory:

Please provide quantitative evidence to demonstrate that Hydro One's incremental asset replacements are incrementally improving reliability and/or incrementally lowering O&M costs.

Response:

Hydro One does not perform incremental asset replacements. Assets are replaced due to deteriorating condition, poor performance, safety concerns, compliance or station reconfiguration. Refer to Exhibit B1, Tab 2, Schedule 5.

Ontario Energy Board (Board Staff) INTERROGATORY #064

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 3.3: Benefits from Integrated Capital Investments, pg. 7

"Cost Avoidance – An integrated capital investment approach enables the system to be reconfigured and standardized, thereby reducing the number of assets within the system. For example, in the 2017 and 2018 test years, Hydro One plans to eliminate 10 transformers and 24 breakers from the system through reconfiguration. This results in avoided capital expenditures of $57 million during the test years."

Interrogatory:

a) Please reconcile the claim that the methodology described above avoided capital expenditures of $57 million in the Test Years when sustaining capital costs have more than doubled over the past 5 years.

b) Please provide detailed explanations of the $57 million savings and the base case against which those savings were calculated.

Response:

a) Integrated capital investment planning allows for holistic station planning as detailed in Exhibit B1, Tab 3, Schedule 2. Asset reduction achieved through design standardization and reconfiguration directly results in avoided capital cost, regardless of an increase in overall sustaining capital requirements that are driven by asset needs, as it results in a direct reduction of assets that would have otherwise been replaced under an asset-centric investment approach. For example, where condition and other risk factors described in Exhibit B1, Tab 2, Schedule 5, have identified a need to replace transformers at a station that presently operates in a non-standard configuration with three transformers, integrated capital planning facilitates the standardization of design in which the preferred alternative would be to replace three transformers with two units of a larger capacity. The reconfiguration of the station to reduce one transformer eliminates the need to replace each transformer individually resulting in avoided capital cost. Refer to Exhibit B1 Tab 3, Schedule 11, Investment Summary Documents S09, S11, S12, S13, S14, S16 and S17, etc.

b) The $57 million in avoided capital expenditure is directly related to the reduction of 10 power transformers and 24 breakers from the transmission system over the 2017 and 2018 test years. Historically, Hydro One has spent approximately $5 million for the planned capital replacement of a step-down transformer and approximately $300 thousand for the planned capital replacement of a low voltage circuit breaker. Through planned reconfiguration, the elimination of 10 step-down transformers and 24 low voltage circuit breakers translates to approximately $50 million in avoided capital expenditures for transformers and approximately $7 million in avoided capital expenditures for circuit breakers. The base case against which these savings were calculated was that in which each of the 10 transformers and 24 circuit breakers would have undergone a direct “like-for-like” replacement under an asset-centric investment approach.

Ontario Energy Board (Board Staff) INTERROGATORY #065

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 3.3: Benefits from Integrated Capital Investments, pg. 7

"Operation & Maintenance Cost Reduction – The reduction of assets through the reconfiguration and standardization of design described above results in less equipment to maintain in the system, reducing maintenance expenses. For example the transformers and breakers eliminated in the test years will result in savings of approximately $2 million in operating and maintenance expenses that would have been required over the life of the assets."

Interrogatory:

a) Please provide detailed explanations of the actual O&M savings resulting from the eliminated transformers and breakers, and the base operational costs against which those savings were calculated.

b) Are there other examples of reconfiguration and standardization of design that have resulted in O&M savings? If yes, please provide detailed explanations of the actual O&M savings for these examples and the base operational cost against which those savings were calculated.

Response:

a) O&M savings for the eliminated transformers and breakers are derived from the present value (PV) of the avoided O&M expenditure over the life of assets within three categories; Preventative Maintenance, Corrective Maintenance and Transformer Refurbishment. Detailed explanations of these categories can be found in Exhibit C1, Tab 2, Schedule 2, Section 3.3. The calculated PV of O&M expenditures over the ESL of a step-down transformer and low voltage circuit breaker are $180 thousand and $10 thousand, respectively. The planned elimination of 10 power transformers and 24 circuit breakers over the test years, result in an avoided O&M commitment of $1.8 million and $240 thousand over the test years, respectively. The O&M savings will be realized in subsequent years as the reduced maintenance is realized.

b) Station reconfiguration projects have only been implemented since 2014. There is insufficient history at this point to validate the expected savings because many projects are still in progress and newly installed equipment does not require initial maintenance.

Ontario Energy Board (Board Staff) INTERROGATORY #066

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 4.1.1: Integrated Station Investments – Introduction, pg. 11

"As noted in Section 3.0 above, efficiency gains are achieved in many cases by replacing all end of life (EOL) components within the station as part of the same project."

Interrogatory:

a) Please explain how Hydro One balances the advantages of early replacement against the additional costs involved in this approach when initiating integrated station projects.

b) Please confirm that the business cases for integrated station projects filed with this application with total costs over $20M include a Present Value analysis of the full-life cycle capital and operating costs of each alternative being considered, and quantify the performance consequence costs attributable to implementing each of the different alternatives evaluated.

c) If detailed business cases have not been prepared for all integrated station projects with total costs over $20M, please provide quantified details of the evaluation methodology that was used to select each of these projects for this application.

Response:

a) Since Hydro One is only bundling EOL assets and their associated systems which would require replacement within a 3 year time frame, the most an asset could be advanced for replacement is 2 years. The majority of station assets have life cycles ranging from 20-60 years so 2 years represents a very small percentage of the overall assets lifecycle. The advantages of work bundling are significant considering construction mobilization and demobilization, efficiencies in planning, reduced maintenance costs associated with asset renewal, engineering, equipment commissioning, reduced outages which result in a reduction in customer interruptions.

b) Business cases for projects include a Net Present Value analysis for considered feasible alternatives. Quantitative as well qualitative performance consequences are analyzed for each project alternative.

c) Not applicable.

Witness: Mike Penstone

Ontario Energy Board (Board Staff) INTERROGATORY #067

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 4.1.3: Summary of Expenditures, pg. 16

"In general, Hydro One's fleet of stations has deteriorated to the point of requiring significant investment to maintain and operate a safe and reliable transmission system."

Interrogatory:

a) Please explain if the situation described above has arisen unexpectedly, or if this situation was expected, please provide the justification for allowing the situation to develop.

b) Did Hydro One conduct cost-benefit analysis in past years to evaluate the long-term rate impact of deferring required Sustaining Capital Investments versus increased operational costs? If yes, please provide documentation of this analysis.

Response:

a) No, this situation has not arisen unexpectedly. The expected service life profile of Hydro One's asset base (reference Exhibit B1, Tab 2, Schedule 4, Section 6) clearly shows that a sizable portion of the asset base is currently operating beyond their normal expected service lives; specifically: 28% of transformers, 9% of breakers and 19% of conductors. Over the next ten years, this will significantly increase to 58% of transformers, 40% of breakers and 42% of conductors operating beyond their normal expected service lives with a looming bow wave of assets reaching their ESL starting in 2030. As such, significant sustainment capital investment will be needed between 2016 and 2030 to address the assets that are at end of life in order to maintain and operate a safe and reliable transmission system. Exhibit B1, Tab 2 Schedule 4, Section 6, outlines the justification for allowing this situation to develop.

b) No, Hydro One has not carried out a cost benefit analysis in past years to evaluate the long term rate impact of deferring required Sustaining capital investments. Hydro One always balances the needs of the assets with available resources.

Ontario Energy Board (Board Staff) INTERROGATORY #068

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 4.1.3: Summary of Expenditures, pg. 17

"A reduction in this program will result in an increase in the length of time required to address degrading performance of air blast circuit breakers at critical network stations, and the integrated rebuild of these stations delivering load to customers. Negative impacts to both system and customer reliability would be a result."

Interrogatory:

Please quantify the claims made in the cited reference, showing the relevant performance history and the calculations used to develop the forecast system and customer reliability degradation that would be caused by reduced levels of capital investment in each major investment category.

Response:

As per the results of the Reliability Risk Model in Exhibit B1, Tab 2, Schedule 4, page 8, the increase in reliability risk are provided in *Table 1: Relative Change in Reliability Risk* which shows a 23% and 16% degradation in reliability risk from the sustainment investment plan proposed under this rate filing as compared to Do Nothing for transformers and breakers, respectively. The customer impacts associated with these unplanned outages (reference Exhibit B1, Tab2, Schedule 4, Section 5) are also exacerbated and directly proportional to the degradation in reliability. This is contrary to customer feedback provided and concern with reliability and power quality (Exhibit B1, Tab 2, Schedule 2). Please refer to Board Staff IR #15a for calculations.

Ontario Energy Board (Board Staff) INTERROGATORY #069

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 4.2.3: Investment Plan, pg. 19

"The purchase of operating spare transformers is in line with Hydro One's probabilistic approach to determine the number of spare requirements. The analysis considers performance trends and supply chain considerations of Hydro One's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spares requirement is intended to replenish inventory that is expected to be drawn down for future failures."

Interrogatory:

Please provide a table showing historic in-stock spares, annual draw-down and annual replenishment for 2012-2016, broken down into the following components:

- Autotransformers (>125 MVA);
- Large Transformers (>42MVA);
- Mid-size Transformers (15 to 42 MVA);
- 500 kV Breakers;
- 345 kV Breakers;
- 230 kV Breakers; and
- 115 kV Breakers.

Response:

The inventory of spare transformers and breakers specifying the draw-down and replenishment levels for each the years 2012 to 2016 is provided in the table below.

In Stock Spares as of Aug 18.	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	9	10	10	7	6
Large Transformers (>42MVA)	31	26	23	23	24
Mid-size Transformers (15 to 42 MVA)	19	18	13	16	16
500kV Breakers	3	3	4	4	5
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	17	18	20	19	18
115kV Breakers	4	6	9	14	13

Annual Draw-Down	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	1	0	1	1	2
Large Transformers (>42MVA)	0	3	2	3	1
Mid-size Transformers (15 to 42 MVA)	1	1	2	0	0
500kV Breakers	0	0	0	0	0
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	0	0	0	1	1
115kV Breakers	0	0	0	0	1

Annual Replenishment	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	0	1	0	0	0
Large Transformers (>42MVA)	3	1	1	3	2
Mid-size Transformers (15 to 42 MVA)	0	1	0	1	0
500kV Breakers	0	0	1	0	1
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	8	1	2	0	0
115kV Breakers	0	2	3	5	0

Ontario Energy Board (Board Staff) INTERROGATORY #070

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 5: Lines, pp. 31-32

"The overall Lines Sustaining Capital spending requirement for the 2017 and 2018 test years are considerably higher than historic years. These spending increases are required to address the overhead lines refurbishment, tower coating needs and insulator replacement needs as described in the Asset Needs Overview found in Exhibit B1, Tab 2, Schedule 6."

Interrogatory:

In Hydro One's risk assessment for projects falling under Lines Sustaining Capital, how much flexibility does Hydro One have in terms of the timing of implementation? Please provide quantified calculations showing the impact of investment timing changes.

Response:

The Lines capital spending requirements for the 2017 and 2018 test years have increased mainly to address the condition of following three transmission line components. Please also refer to Board Staff 15, part (e).

1. **Conductors:** Hydro One's transmission lines refurbishment program is driven by condition of the conductor(s). All conductors on selected circuits for refurbishment have been assessed through laboratory tests. Those selected for 2017 and 2018 refurbishment programs are confirmed to be at end of life, with low remaining strength or low torsional ductility, increasing the probability of catastrophic line drop incidents. Given the confirmed condition of the assets and associated safety and reliability risks, Hydro One does not have flexibility in timing of these projects.

2. **Tower Coating:** Hydro One's strategy for its steel structures is to extend the life of these assets in the most economical way. The steel structures identified for coating are in areas highly corrosive to the towers' protective coating. Failure to recoat the towers before corrosion sets in will require replacement of the entire tower, as described in Exhibit B1, Tab 2, Schedule 6. Hydro One has determined approximately 7,500 towers need to be coated over the next 5 years, (with an additional 4,700 in the following 5 years), as identified within this application. Hydro One believes the 5 years in the transmission system plan and in particular the test years, to be the optimal time to proceed with this project, given the number of towers and their condition.

3. **Insulators:** Insulator replacement requirements are due to defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) and installed in Hydro One system between 1965 and 1982. In the next 5 years, the insulator replacement program is targeting critical structures such as publicly accessible locations or road crossings. In 2017 and 2018, Hydro One is particularly targeting the replacement of these defective insulators at elevated safety risk locations such as 400 series highways. Given the confirmed condition of the assets and associated safety and reliability risks, Hydro One does not have flexibility in timing of these projects.

Ontario Energy Board (Board Staff) INTERROGATORY #071

Reference:

Exhibit B1/Tab3/Sch 3 – Section 2: Development Capital Investments, Table 1 – Development Capital, pg. 4

Interrogatory:

With regard to this table, please explain what drove the increased spending levels for Inter Area Network Transfer Capability, Local Area Supply Adequacy, and Load Customer Connection investments in 2012.

Response:

The increased spending in 2012 for Inter Area Network Transfer Capability is mainly due to the New 500 kV Bruce to Milton Double Circuit Transmission Line project with a 2012 expenditure of $100 million.

The increased spending in 2012 for Local Area Supply Adequacy is mainly due to the Toronto Area Station Upgrades for Short Circuit Capability projects (Hearn SS, Leaside TS, and Manby TS) with a combined 2012 expenditure of $54 million.

The 2012 expenditure for Load Customer Connection is higher compared to the other historic years mainly due to the new Commerce Way TS with a 2012 expenditure of $25 million.

Ontario Energy Board (Board Staff) INTERROGATORY #072

Reference:

Exhibit B1/Tab3/Sch 3 – Section 2.1.1: Description of Inter-Area Network Transfer Capability Investments, Table 2 – Inter-Area Network Transfer Capability: Summary of Development Capital Projects in Excess of $3 Million, pg. 7

Table 2: Inter-Area Network Transfer Capability:

Summary of Development Capital Projects in Excess of $3 Million

ISD #	Investment Description	Capital Project Category[1]	Gross Capital Expenditures ($ Millions)										In-Service Years
			Historic				Bridge	Test		Gross Total Cost[2]	Capital Contribution[3]	Net Total Cost[4]	
			2012	2013	2014	2015	2016	2017	2018				
D01	Clarington TS: Build new 500/230kV Station	2	6.8	4.5	30.1	79.3	76.7	68.6	14.8	280.7	0.0	280.7	Q4 2018
D02	Nanticoke TS: Connect HVDC Lake Erie Circuit	3	0.0	0.0	0.0	0.0	1.0	5.0	13.0	36.0	36.0	0.0	Q4 2019
D03	Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade	4	0.0	0.0	0.0	0.0	0.3	2.5	8.0	20.0	0.0	20.0	Q1 2020
D04	East-West Tie Expansion: Station Work	3	0.0	0.0	1.0	0.1	0.0	3.0	30.0	166.1	0.0	166.1	Q4 2020
D05	Milton SS: Station Expansion and Connect 230kV Circuits	4	0.0	0.0	0.0	0.0	0.1	2.0	5.0	250.0	0.0	250.0	Q2 2022
	Other Projects <$3M (2017-18 Cash flows)[5]		0.0	0.1	0.1	6.9	16.9	3.7	2.0				
	Other Historical Projects (pre-2017)[6]		111.0	37.1	15.2	0.0	0.0	0.0	0.0				
		Total Gross	**117.8**	**41.7**	**46.4**	**86.3**	**94.9**	**84.8**	**72.8**				
		Capital Contribution	*0.0*	*0.0*	*(0.5)*	*0.0*	*(1.0)*	*(5.0)*	*(13.0)*				
		Total Net	**117.8**	**41.7**	**45.9**	**86.3**	**93.9**	**79.8**	**59.8**				

Interrogatory:

a) Please provide the forecast spending trend to project completion for the projects listed in Table 2 that have in-service years that extend past 2018.

b) Does Hydro One consider that the scope, schedule and cost of all projects shown in Table 2 above are non-discretionary? If yes, please provide a detailed explanation showing why each project is considered to be non-discretionary during the test years.

c) Does Hydro One or ratepayers face any cost overrun risk if the Nanticoke TS project final costs exceed the customer contribution amount of $36 million?

Response:

a) Hydro One is only seeking Board approval for projects with an in-service date in the test years (2017 or 2018) within this rate application. Board approval for the projects with an in-service date beyond the test years will be sought in either a future Leave to Construct or

Transmission Rate application. The five year forecast spending for total Development capital is presented in Table 1 in Exhibit B1, Tab 3, Schedule 1.

b) All of the projects identified in Table 2 are non-discretionary as defined in the OEB Filing Requirements for Electricity Transmission Applications; explanations for this classification are provided in the table below. For further details on the projects please refer to Exhibit B1, Tab 3, Schedule 11, Investment Summary Documents Ref. #: D01 to D05.

ISD #	Non-Discretionary Trigger	Explanation of Non-Discretionary Classification
D01	- Satisfy an obligation specified by the IESO - Need to address levels of supply security	In a letter dated February 8, 2016, the IESO confirmed the need for completing the Clarington TS project to provide the required levels of supply security and restoration capability by 2018 and also to mitigate a very high impact risk should OPG not receive approval from the CNSC when their current license expires in August 2018. The expenditures in the test years are necessary to meet the 2018 in-service date.
D02	- Need to connect new customer connection	Hydro One is obligated to under its electricity transmission license to connect any customer that requests connection to Hydro One's transmission system. The expenditures shown in the test years are required to meet the 2019 in-service date.
D03	- Required to achieve provincial government objectives	This project is required to increase the loading capability of the 230 kV circuits (M30A/M31A) in order to facilitate firm import capacity from Quebec as per the November 2014 Memorandum of Understanding on the Seasonal Capacity Exchange agreement between the Provinces of Ontario and Quebec. The expenditures shown in the test years are required to meet the 2020 in-service date.
D04	- Required to achieve provincial government policy objectives	The Ministry of Energy, in a letter dated March 10, 2016, informed the Ontario Energy Board that under the authority of section 96.1 (1) of the Ontario Energy Board Act, 1998, the Lieutenant Governor in Council made an order declaring that the construction of the East-West Tie transmission line is needed as a priority project. The expenditures shown in the test years are required to meet the 2020 in-service date.
D05	- Satisfy an obligation specified by the IESO	This project was recommended by the IESO in the Northwest GTA Integrated Regional Resource Plan. The expenditures in the test years are required to meet the 2022 in-service date.

c) No. The Nanticoke TS: Connect HVDC Lake Erie Circuit is a transmission interconnection project that is fully funded by the proponent; therefore there is no risk to Hydro One or ratepayers for cost overruns.

Ontario Energy Board (Board Staff) INTERROGATORY #073

Reference:

Exhibit B1/Tab3/Sch 3 – Section 2.2.1: Description of Local Area Supply Investments, Table 3 – Local Area Supply Adequacy: Summary of Development Capital Projects in Excess of $3 Million, pg. 14

Table 3: Local Area Supply Adequacy: Summary of Development Capital Projects in Excess of $3 Million

ISD #	Investment Description	Capital Project Category	Gross Capital Expenditures ($ Millions)										In-Service Years
			Historic				Bridge	Test		Gross Total Cost[1]	Capital Contri-bution[2]	Net Total Cost[3]	
			2012	2013	2014	2015	2016	2017	2018				
D06	Galt Junction: Install In-Line Switches on M20D/M21D Circuits	2	0.0	0.0	0.0	0.2	0.7	3.6	0.1	4.5	0.0	4.5	Q2 2017
D07	York Region: Increase Transmission Capability for B82V/B83V Circuits	2	0.0	0.0	0.2	1.2	7.5	22.6	0.2	31.8	0.0	31.8	Q4 2017
D08	Hawthorne TS: Autotransformer Upgrades	2	0.0	0.0	0.0	0.2	2.0	8.0	5.8	16.0	0.0	16.0	Q2 2018
D09	Brant TS: Install 115kV Switching Facilities	3	0.0	0.0	0.0	0.0	0.2	5.0	6.0	12.0	12.0	0.0	Q1 2019
D10	Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits	3	0.0	0.0	0.0	0.0	1.0	2.4	4.2	8.7	4.3	4.4	Q2 2019
D11	Southwest GTA Transmission Reinforcement	4	0.0	0.0	0.0	0.0	0.1	0.9	5.0	30.0	0.0	30.0	Q2 2020
D12	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	4	0.0	0.0	0.0	0.0	1.0	4.0	20.0	80.0	0.0	80.0	Q4 2020
	Other Projects <$3M (2017-18 Cash flows)[4]		0.5	1.1	13.3	42.1	18.8	3.9	13.0				
	Other Historical Projects (pre-2017)[5]		95.2	60.8	47.7	52.1	27.3	0.0	0.0				
		Total Gross	**95.7**	**61.9**	**61.2**	**95.8**	**58.5**	**50.5**	**54.3**				
		Capital Contribution	*(9.2)*	*(7.9)*	*(12.1)*	*(30.9)*	*(10.3)*	*(6.7)*	*(8.6)*				
		Total Net	**86.4**	**54.0**	**49.1**	**64.9**	**48.2**	**43.8**	**45.7**				

Interrogatory:

Are any of the "Other Projects < $3M" discretionary? If yes, please identify those projects.

Response:

No. All of the projects included in "Other Projects < $3M" are non-discretionary.

Witness: Bing Young

Ontario Energy Board (Board Staff) INTERROGATORY #074

Reference:

Exhibit B1/Tab3/Sch 3 – Section 2.3.1: Description of Load Customer Connection Investments, Table 4 – Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million, pg. 21

Table 4: Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

ISD #	Investment Description	Capital Project Category	Gross Capital Expenditures ($ Millions)										In-Service Years
			Historic				Bridge	Test		Gross Total Cost[1]	Capital Contri-bution[2]	Net Total Cost[3]	
			2012	2013	2014	2015	2016	2017	2018				
D13	Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D	2	0.0	0.0	0.1	1.1	0.4	10.0	5.9	17.5	14.0	3.5	Q1 2018
D14	Supply to Essex County Transmission Reinforcement	1	0.2	0.3	0.2	0.8	3.7	33.0	31.4	72.3	21.0	51.3	Q2 2018
D15	Horner TS: Build 230/27.6kV Transformer Station	2	0.0	0.0	0.0	0.0	3.0	16.0	13.0	32.0	26.9	5.1	Q2 2018
D16	Lisgar TS: Transformer Upgrades	2	0.0	0.0	0.0	0.1	1.0	10.3	2.5	13.9	3.9	10.0	Q2 2018
D17	Seaton MTS: Provide 230kV Line Connection	4	0.0	0.1	0.0	0.0	0.7	3.3	3.0	7.1	4.8	2.3	Q2 2018
D18	Hanmer TS: Build 230/44kV Transformer Station	3	0.0	0.0	0.0	0.0	0.2	9.5	18.5	30.0	5.6	24.4	Q1 2019
D19	Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits	4	0.0	0.0	0.0	0.0	5.0	23.0	17.0	47.0	21.8	25.2	Q1 2019
D20	Toyota Woodstock: Upgrade Station	4	0.0	0.0	0.0	0.0	0.5	3.0	2.5	6.0	6.0	0.0	Q1 2019
D21	Enfield TS: Build 230/44kV Transformer Station	3	0.0	0.0	0.0	0.0	0.5	10.0	15.0	33.1	22.4	10.7	Q2 2019
D22	TransCanada: Energy East Pipeline Conversion	3	0.0	0.0	0.8	0.6	1.0	1.9	10.2	175.6	175.6	0.0	Q4 2021
	Other Projects <$3M (2017-18 Cash flows)[4]		0.3	3.4	16.9	5.9	12.6	6.0	2.5				
	Other Historical Projects (pre-2017)[5]		75.3	38.5	32.2	11.6	9.1	0.0	0.0				
		Total Gross	**75.8**	**42.3**	**50.2**	**20.1**	**37.7**	**126.0**	**121.5**				
		Capital Contribution	*(15.2)*	*(17.6)*	*(35.6)*	*(12.4)*	*(21.6)*	*(67.9)*	*(64.1)*				
		Total Net	**60.6**	**24.7**	**14.6**	**7.7**	**16.0**	**58.1**	**57.4**				

Interrogatory:

a) Please provide Capital Contribution calculations for all projects with Net Total Cost above $10 million.

b) Please compare these customer contribution calculations with the customer contribution calculations for the planned transformer station additions at Milton and Halton Hills.

Response:

a) Please refer to Appendix A for the capital contribution calculations for all projects with a net total cost exceeding $10 million. Please note that the capital contribution calculations for projects outside of the test years were originally filed as high level budgetary estimates;

however calculations in accordance with Section 6.5 of the Transmission System Code have since been undertaken and provided in Appendix A.

Furthermore, Hydro One has received a letter from the customer Hydro Ottawa as documented in Appendix A to cancel the Lisgar TS Transformer Upgrades project (Ref #D16); therefore no capital contribution calculation is provided.

b) Hydro One’s 2017 to 2018 capital expenditure plan does not include transformer station additions at either Milton or Halton Hills; therefore there are no capital contributions for Hydro One to compare.

Appendix A

The Capital Contribution Calculations for Projects with Net Total Cost >$10 million

Project D14 - Supply to Essex County Transmission Reinforcement

Date:	7-Apr-16
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

hydro one

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Line Pool Capital Contribution
Customer:	Hydro One Distribution

		Month / Year	In-Service Date Jun-30 2018	<------- Project year ended - annualized from In-Service Date -------> Jun-30 2019	Jun-30 2020	Jun-30 2021	Jun-30 2022	Jun-30 2023 (1st true-up)	Jun-30 2024	Jun-30 2025	Jun-30 2026	Jun-30 2027	Jun-30 2028 (2nd true-up)	Jun-30 2029	Jun-30 2030
			0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast															
Load Forecast (MW)				96.3	99.5	102.8	103.6	104.4	105.2	106.1	106.9	107.7	108.5	109.4	110.2
Load adjustments (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				96.3	99.5	102.8	103.6	104.4	105.2	106.1	106.9	107.7	108.5	109.4	110.2
Tariff Applied ($/kW/Month)				0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Incremental Revenue - $k				1,005.0	1,039.0	1,073.1	1,081.6	1,090.1	1,098.7	1,107.3	1,115.9	1,124.5	1,133.1	1,141.8	1,150.4
Removal Costs - $k			0.0												
On-going OM&A Costs - $k			0.0	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)
Municipal Tax - $k				(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)
Net Revenue/(Costs) before taxes - $k			0.0	863.5	897.5	931.5	940.0	948.6	957.1	965.7	974.3	983.0	991.6	1,000.2	1,008.9
Income Taxes - $k			0.0	19.8	239.5	192.3	154.9	120.3	88.3	58.7	31.2	5.8	(17.8)	(39.7)	(60.0)
Operating Cash Flow (after taxes) - $k			0.0	883.2	1,137.0	1,123.8	1,094.9	1,068.9	1,045.4	1,024.4	1,005.6	988.7	973.8	960.5	948.9
		Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $k	(A)	13,243.7	0.0	858.8	1,045.1	976.6	899.6	830.2	767.7	711.1	659.9	613.5	571.2	532.6	497.4
Capital Expenditures - $k															
Capital cost before overheads & AFUDC - $k			(25,858.5)												
- Overheads - $k			(3,826.4)												
- AFUDC - $k			(943.4)												
Total upfront capital expenditures - $k			**(30,628.4)**												
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0												
Total capital expenditures - $k			**(30,628.4)**												
PV CCA Residual Tax Shield - $k			**115.0**												
PV Working Capital - $k			**0.0**												
PV Capital (after taxes) - $k	(B)	(30,513.3)	**(30,513.3)**												
Cumulative PV Cash Flow (after taxes) - $k	(A) + (B)	(17,269.6)	**(30,513.3)**	**(29,654.5)**	**(28,609.4)**	**(27,632.8)**	**(26,733.2)**	**(25,903.0)**	**(25,135.4)**	**(24,424.2)**	**(23,764.3)**	**(23,150.9)**	**(22,579.7)**	**(22,047.0)**	**(21,549.6)**

	Jun-30 2031	Jun-30 2032	Jun-30 2033 (3rd true-up)	Jun-30 2034	Jun-30 2035	Jun-30 2036	Jun-30 2037	Jun-30 2038	Jun-30 2039	Jun-30 2040	Jun-30 2041	Jun-30 2042	Jun-30 2043
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	111.0	111.8	112.7	113.5	114.3	115.1	116.0	116.8	117.6	118.5	119.3	120.1	121.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	111.0	111.8	112.7	113.5	114.3	115.1	116.0	116.8	117.6	118.5	119.3	120.1	121.0
Tariff Applied ($/kW/Month)	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Incremental Revenue - $k	1,159.0	1,167.7	1,176.3	1,184.9	1,193.5	1,202.1	1,210.7	1,219.4	1,228.0	1,236.7	1,245.4	1,254.2	1,262.9
Removal Costs - $k													
On-going OM&A Costs - $k	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)	(13.3)
Municipal Tax - $k	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)	(128.2)
Net Revenue/(Costs) before taxes - $k	1,017.5	1,026.1	1,034.8	1,043.4	1,052.0	1,060.6	1,069.2	1,077.8	1,086.5	1,095.2	1,103.9	1,112.6	1,121.4
Income Taxes - $k	(78.9)	(96.4)	(112.8)	(128.0)	(142.1)	(155.3)	(167.7)	(179.2)	(190.0)	(200.2)	(209.7)	(218.6)	(227.0)
Operating Cash Flow (after taxes) - $k	938.6	929.7	922.0	915.4	909.9	905.3	901.5	898.6	896.5	895.0	894.2	894.0	894.4
PV Operating Cash Flow (after taxes) - $k (A)	465.2	435.6	408.4	383.4	360.2	338.8	319.0	300.6	283.5	267.6	252.8	238.9	225.9
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(21,084.4)**	**(20,648.8)**	**(20,240.4)**	**(19,857.0)**	**(19,496.8)**	**(19,158.0)**	**(18,839.0)**	**(18,538.4)**	**(18,254.8)**	**(17,987.2)**	**(17,734.5)**	**(17,495.6)**	**(17,269.6)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.78%**

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		15,168.2		15,168.2	
PV OM&A Costs		(179.2)		(179.2)	
PV Municipal Tax		(1,721.7)		(1,721.7)	
PV Income Taxes		(3,515.8)		(3,515.8)	0.0
PV CCA Tax Shield		3,607.3		1,301.8	(2,305.5)
PV Capital - Upfront	(30,628.4)		(30,628.4)		
Add: PV **Capital Contribution**	**0.0**	(30,628.4)	**19,575.1**	(11,053.3)	19,575.1
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		(17,269.6)		(0.0)	17,269.6
Profitability Index*		**0.4**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2018	19,575.1		19,575.1
Total		**19,575.1**	**0.0**	**19,575.1**
Contribution Required (before HST)				**19,575.1**
HST @ 13%				2,544.8
Contribution Required (including HST)[1]				**22,119.9**

Notes:
1) Payment from customer must include HST.

Other Assumptions		**Notes:**
In-Service Date:	30-Jun-18	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income tax
Ontario Corporation Income Tax	11.50%	2016 provincial corporate income tax
Working cash net lag days	-1.04	As per Lead Lag Study as prepared by Navigant for 2015/2016 rates
CCA Rate for Class 47 Assets	8%	100% Class 47 assets except for Land

Calculation Time Stamp: 07-Apr-16, 9:02 PM

Date:	7-Apr-16
Project #	17503

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

hydro one

Facility Name:	Supply to Essex County Transmission Reinforcement
Description:	Transformation Pool Capital Contribution
Customer:	Hydro One Distribution

<----- Project year ended - annualized from In-Service Date ----->

Month / Year	Cumulative PV @ 5.78%	In-Service Date Jun-30 2018 (0)	Jun-30 2019 (1)	Jun-30 2020 (2)	Jun-30 2021 (3)	Jun-30 2022 (4)	Jun-30 2023 (5) 1st true-up	Jun-30 2024 (6)	Jun-30 2025 (7)	Jun-30 2026 (8)	Jun-30 2027 (9)	Jun-30 2028 (10) 2nd true-up	Jun-30 2029 (11)	Jun-30 2030 (12)
Revenue & Expense Forecast														
Load Forecast (MW)			96.3	99.5	102.8	103.6	104.4	105.2	106.1	106.9	107.7	108.5	109.4	110.2
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			96.3	99.5	102.8	103.6	104.4	105.2	106.1	106.9	107.7	108.5	109.4	110.2
Tariff Applied ($/kW/Month)			2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k			2,333.4	2,412.4	2,491.5	2,511.2	2,531.1	2,550.9	2,570.9	2,590.9	2,610.9	2,630.9	2,651.0	2,671.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(251.7)	(251.7)	(251.7)	(251.7)	(251.7)	(503.4)	(503.4)	(503.4)	(503.4)	(503.4)	(503.4)	(503.4)
Municipal Tax - $k			(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)
Net Revenue/(Costs) before taxes - $k		0.0	1,975.0	2,054.0	2,133.1	2,152.9	2,172.7	1,940.9	1,960.8	1,980.8	2,000.8	2,020.8	2,040.9	2,061.0
Income Taxes - $k		0.0	(258.0)	(34.8)	(96.5)	(139.3)	(179.0)	(149.3)	(183.8)	(216.0)	(246.0)	(274.0)	(300.3)	(324.8)
Operating Cash Flow (after taxes) - $k		0.0	1,717.0	2,019.2	2,036.6	2,013.6	1,993.7	1,791.5	1,777.0	1,764.8	1,754.8	1,746.8	1,740.6	1,736.1
PV Operating Cash Flow (after taxes) - $k (A)	24,091.9	**0.0**	**1,669.5**	**1,856.1**	**1,769.8**	**1,654.3**	**1,548.5**	**1,315.5**	**1,233.6**	**1,158.2**	**1,088.8**	**1,024.6**	**965.2**	**910.2**
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(21,616.6)												
- Overheads - $k		(3,177.6)												
- AFUDC - $k		(699.3)												
Total upfront capital expenditures - $k		**(25,493.6)**												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		**(25,493.6)**												
PV CCA Residual Tax Shield - $k		**122.8**												
PV Working Capital - $k		**0.9**												
PV Capital (after taxes) - $k (B)	**(25,369.9)**	**(25,369.9)**												
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(1,277.9)**	**(25,369.9)**	**(23,700.4)**	**(21,844.3)**	**(20,074.4)**	**(18,420.2)**	**(16,871.7)**	**(15,556.2)**	**(14,322.6)**	**(13,164.4)**	**(12,075.6)**	**(11,051.0)**	**(10,085.8)**	**(9,175.7)**

Month / Year	Jun-30 2031 (13)	Jun-30 2032 (14)	Jun-30 2033 (15) 3rd true-up	Jun-30 2034 (16)	Jun-30 2035 (17)	Jun-30 2036 (18)	Jun-30 2037 (19)	Jun-30 2038 (20)	Jun-30 2039 (21)	Jun-30 2040 (22)	Jun-30 2041 (23)	Jun-30 2042 (24)	Jun-30 2043 (25)
Revenue & Expense Forecast													
Load Forecast (MW)	111.0	111.8	112.7	113.5	114.3	115.1	116.0	116.8	117.6	118.5	119.3	120.1	121.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	111.0	111.8	112.7	113.5	114.3	115.1	116.0	116.8	117.6	118.5	119.3	120.1	121.0
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k	2,691.1	2,711.1	2,731.2	2,751.2	2,771.2	2,791.1	2,811.1	2,831.2	2,851.3	2,871.5	2,891.7	2,912.0	2,932.3
Removal Costs - $k													
On-going OM&A Costs - $k	(503.4)	(503.4)	(503.4)	(629.2)	(629.2)	(629.2)	(629.2)	(629.2)	(629.2)	(629.2)	(629.2)	(629.2)	(629.2)
Municipal Tax - $k	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)	(106.7)
Net Revenue/(Costs) before taxes - $k	2,081.0	2,101.1	2,121.1	2,015.3	2,035.3	2,055.2	2,075.2	2,095.3	2,115.4	2,135.6	2,155.8	2,176.1	2,196.4
Income Taxes - $k	(347.9)	(369.5)	(389.8)	(375.5)	(393.5)	(410.4)	(426.5)	(441.7)	(456.1)	(469.8)	(482.8)	(495.3)	(507.2)
Operating Cash Flow (after taxes) - $k	1,733.2	1,731.6	1,731.4	1,639.8	1,641.8	1,644.8	1,648.8	1,653.6	1,659.3	1,665.8	1,673.0	1,680.8	1,689.2
PV Operating Cash Flow (after taxes) - $k (A)	**859.0**	**811.4**	**766.9**	**686.7**	**650.0**	**615.6**	**583.4**	**553.2**	**524.8**	**498.0**	**472.9**	**449.1**	**426.7**
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(8,316.7)**	**(7,505.3)**	**(6,738.4)**	**(6,051.7)**	**(5,401.7)**	**(4,786.1)**	**(4,202.7)**	**(3,649.5)**	**(3,124.7)**	**(2,626.7)**	**(2,153.8)**	**(1,704.7)**	**(1,277.9)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 5.78%

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		35,218.1		35,218.1	
PV OM&A Costs		(6,078.6)		(6,078.6)	
PV Municipal Tax		(1,433.0)		(1,433.0)	
PV Income Taxes		(7,342.2)		(7,342.2)	(0.0)
PV CCA Tax Shield		3,850.5		3,623.2	(227.4)
PV Capital - Upfront	(25,493.6)		(25,493.6)		
Add: PV **Capital Contribution**	**0.0**	(25,493.6)	**1,505.3**	(23,988.3)	1,505.3
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.9		0.9	
PV Surplus / (Shortfall)		(1,277.9)		(0.0)	1,277.9
Profitability Index*		0.9		1.0	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2018	1,505.3		1,505.3
Total		1,505.3	0.0	1,505.3
Contribution Required (before HST)				**1,505.3**
HST @ 13%				195.7
Contribution Required (including HST)[1]				**1,701.0**

Notes:
1) Payment from customer must include HST.

Other Assumptions		Notes:
In-Service Date:	30-Jun-18	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income tax
Ontario Corporation Income Tax	11.50%	2016 provincial corporate income tax
Working cash net lag days	-1.04	As per Lead Lag Study as prepared by Navigant for 2015/2016 rates
CCA Rate for Class 47 Assets	8%	100% Class 47 assets except for Land

Calculation Time Stamp: 07-Apr-16, 9:00 PM

Project D16 - Lisgar TS: Transformer Upgrades

HydroOttawa

August 16th, 2016

John Walewski, P.Eng.
Manager – Network Connections
Hydro One Networks Inc.
433 Bay Street
Toronto, Ontario M5G 2P5

Dear Mr. Walewski,

Hydro Ottawa would like to extend its thanks for your aide in the CCRA discussions regarding the transformation upgrade at Lisgar TS. Due to a recent application for generation connection at Lisgar TS, Hydro Ottawa will no longer be moving forward with its application for transformer replacement.

Hydro Ottawa has reviewed its loading forecasts for its downtown supply area and will be moving forward with submitting a connection cost estimate agreement to upgrade the transformation at King Edward TK with Hydro One.

Sincerely,

Christopher Murphy, EIT
Distribution Engineer/Ingénieur, Distribution de l'électricité
Tel. / tél. 613-738-5499 | ext. / poste 7114
christophermurphy@hydroottawa.com

e-cc: Hydro Ottawa – Casey Malone
Hydro Ottawa – Kyle Epp
Hydro Ottawa – Matthew McGrath
Hydro One Networks Inc. – Nafiz Somjee
Hydro One Networks Inc. – Raj Ghai

Hydro Ottawa Limited / Hydro Ottawa limitée
3025 Albion Road North, PO Box 8700 / chemin Albion Nord, C.P. 8700
Ottawa, Ontario K1G 3S4

www.hydroottawa.com

1 **Project D18 - Hanmer TS: Build 230/44kV Transformer Station**

Date :	16-Aug-16
Project#	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

hydro one

Facility Name: 2017/2018 TX Rate Case - Hanmer TS Build 230/44kV Transformer Station
Description: ISD# D18
Customer:

<-------- Project year ended - annualized from In-Service Date -------->

Month / Year	Cumulative PV @ 5.78%	In-Service Date Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029	Mar-31 2030	Mar-31 2031
							1st true-up					2nd true-up		
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)			2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $k			(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)
Net Revenue/(Costs) before taxes - $k		0.0	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)
Income Taxes - $k		0.0	187.3	343.4	317.3	293.4	271.3	251.0	232.4	215.2	199.4	184.9	171.5	159.2
Operating Cash Flow (after taxes) - $k		0.0	120.4	276.4	250.4	226.4	204.3	184.1	165.4	148.2	132.4	117.9	104.5	92.2
PV Operating Cash Flow (after taxes) - $k (A)	1,721.4	0.0	117.1	254.1	217.6	186.0	158.7	135.2	114.8	97.3	82.2	69.2	58.0	48.4
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(16,000.0)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(16,000.0)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(16,000.0)												
PV CCA Residual Tax Shield - $k		78.5												
PV Working Capital - $k		0.0												
PV Capital (after taxes) - $k (B)	(15,921.5)	(15,921.5)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(14,200.1)	(15,921.5)	(15,804.5)	(15,550.4)	(15,332.8)	(15,146.8)	(14,988.1)	(14,852.9)	(14,738.1)	(14,640.8)	(14,558.7)	(14,489.5)	(14,431.5)	(14,383.2)

	Mar-31 2032	Mar-31 2033	Mar-31 2034	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
			3rd true-up										
	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
On-going OM&A Costs - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $k	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)
Net Revenue/(Costs) before taxes - $k	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)	(67.0)
Income Taxes - $k	147.9	137.5	127.9	119.1	111.0	103.5	96.7	90.3	84.5	79.2	74.3	69.8	65.6
Operating Cash Flow (after taxes) - $k	80.9	70.5	60.9	52.1	44.0	36.6	29.7	23.4	17.6	12.2	7.3	2.8	(1.4)
PV Operating Cash Flow (after taxes) - $k (A)	40.1	33.0	27.0	21.8	17.4	13.7	10.5	7.8	5.6	3.7	2.1	0.7	(0.3)
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(14,343.1)	(14,310.0)	(14,283.1)	(14,261.2)	(14,243.8)	(14,230.1)	(14,219.6)	(14,211.8)	(14,206.2)	(14,202.6)	(14,200.5)	(14,199.8)	(14,200.1)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - %: 5.78%

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		0.0		0.0	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(899.4)		(899.4)	
PV Income Taxes		238.3		238.3	0.0
PV CCA Tax Shield		2,460.9		(120.2)	(2,581.1)
PV Capital - Upfront	(16,000.0)		(16,000.0)		
Add: PV Capital Contribution	0.0	(16,000.0)	16,781.2	781.2	16,781.2
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		(14,200.1)		(0.0)	14,200.1
Profitability Index*		0.1		(1.0)	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatio	2019	16,781.2		16,781.2
Total		16,781.2	0.0	16,781.2
Contribution Required (before HST				16,781.2
HST @ 13%				2,181.6
Contribution Required (including HST				18,962.8

Notes:
1) Payment from customer must include HST.

Other Assumptions		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income tax
Ontario Corporation Income Ta	11.50%	2016 provincial corporate income tax
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 16-Aug-16, 3:42 PM

2

1 **Project D19 – Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits**

Date: 16-Aug-16
Project#

SUMMARY OF CONTRIBUTION CALCULATIONS
Line Pool - Estimated cost

hydro one

Facility Name: 2017/2018 TX Rate Case - Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits
Description: ISD #D19
Customer:

Project year ended - annualized from In-Service Date

	Month / Year	In-Service Date Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024 (1st true-up)	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029 (2nd true-up)	Mar-31 2030	Mar-31 2031
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			19.3	23.6	33.6	36.9	40.4	44.3	47.6	50.6	52.9	54.3	55.4	57.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			19.3	23.6	33.6	36.9	40.4	44.3	47.6	50.6	52.9	54.3	55.4	57.0
Tariff Applied ($/kW/Month)			0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Incremental Revenue - $k			201.2	246.1	351.0	385.2	421.6	462.3	496.5	528.6	552.2	567.2	577.9	595.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $k			(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)
Net Revenue/(Costs) before taxes - $k		0.0	93.0	137.9	242.8	277.1	313.4	354.1	388.3	420.4	444.0	459.0	469.7	486.8
Income Taxes - $k		0.0	249.4	489.5	419.7	371.9	326.6	283.1	243.8	207.6	175.8	148.4	123.9	99.5
Operating Cash Flow (after taxes) - $k		0.0	342.4	627.5	662.5	648.9	640.0	637.2	632.2	628.0	619.8	607.3	593.6	586.3
	Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $k (A)	7,857.4	0.0	332.9	576.8	575.7	533.1	497.1	467.9	438.8	412.2	384.6	356.2	329.2	307.4
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(25,850.0)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(25,850.0)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(25,850.0)												
PV CCA Residual Tax Shield - $k		126.8												
PV Working Capital - $k		0.0												
PV Capital (after taxes) - $k (B)	(25,723.2)	(25,723.2)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(17,865.8)	(25,723.2)	(25,390.3)	(24,813.5)	(24,237.8)	(23,704.7)	(23,207.6)	(22,739.7)	(22,300.9)	(21,888.7)	(21,504.2)	(21,147.9)	(20,818.7)	(20,511.4)

	Mar-31 2032	Mar-31 2033	Mar-31 2034 (3rd true-up)	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	58.6	60.1	61.1	62.5	63.6	65.0	66.0	67.4	68.5	69.9	70.9	72.4	73.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	58.6	60.1	61.1	62.5	63.6	65.0	66.0	67.4	68.5	69.9	70.9	72.4	73.0
Tariff Applied ($/kW/Month)	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Incremental Revenue - $k	612.1	627.1	637.8	652.8	663.5	678.4	689.1	704.1	714.8	729.8	740.5	755.5	761.9
On-going OM&A Costs - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $k	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)	(108.2)
Net Revenue/(Costs) before taxes - $k	503.9	518.9	529.6	544.6	555.3	570.3	581.0	595.9	606.6	621.6	632.3	647.3	653.7
Income Taxes - $k	76.7	55.9	37.6	19.4	3.5	(12.5)	(26.5)	(40.6)	(52.9)	(65.5)	(76.2)	(87.5)	(95.9)
Operating Cash Flow (after taxes) - $k	580.6	574.8	567.2	564.0	558.8	557.7	554.5	555.3	553.8	556.2	556.1	559.8	557.8
PV Operating Cash Flow (after taxes) - $k (A)	287.8	269.3	251.3	236.2	221.2	208.7	196.2	185.8	175.1	166.3	157.2	149.6	140.9
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(20,223.6)	(19,954.3)	(19,703.0)	(19,466.8)	(19,245.6)	(19,036.9)	(18,840.7)	(18,654.9)	(18,479.8)	(18,313.5)	(18,156.3)	(18,006.7)	(17,865.8)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - %: 5.78%

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		6,906.5		6,906.5	
PV OM&A Costs		0.0		0.0	
PV Municipal Tax		(1,453.1)		(1,453.1)	0.0
PV Income Taxes		(1,446.2)		(1,446.2)	0.0
PV CCA Tax Shield		3,975.9		728.6	(3,247.4)
PV Capital - Upfront	(25,850.0)		(25,850.0)		
Add: PV Capital Contribution	0.0	(25,850.0)	21,113.2	(4,736.8)	21,113.2
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.0		0.0	
PV Surplus / (Shortfall)		(17,865.8)		0.0	17,865.8
Profitability Index*		0.3		1.0	

Notes:
* PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatio	2019	21,113.2		21,113.2
Total		21,113.2	0.0	21,113.2
Contribution Required (before HST				21,113.2
HST @ 13%				2,744.7
Contribution Required (including HST[1]				23,857.9

Notes:
1) Payment from customer must include HST.

Other Assumptions		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income tax
Ontario Corporation Income Tax	11.50%	2016 provincial corporate income tax
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 16-Aug-16, 2:58 PM

2

Date: 15-Aug-16
Project#

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

hydro one

Facility Name: 2017/2018 TX Rate Case - Runnymede TS: Build 115/27.6kV TS and Reconductor 115kV Circuits
Description: ISD# D19
Customer:

In-Service Date / <------- Project year ended - annualized from In-Service Date -------->

	Cumulative PV @ 5.78%	Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029	Mar-31 2030	Mar-31 2031
Month / Year		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			19.3	23.6	33.6	36.9	40.4	44.3	47.6	50.6	52.9	54.3	55.4	57.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			19.3	23.6	33.6	36.9	40.4	44.3	47.6	50.6	52.9	54.3	55.4	57.0
Tariff Applied ($/kW/Month)			2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k			467.1	571.5	814.9	894.5	978.9	1,073.3	1,152.9	1,227.4	1,282.1	1,316.8	1,341.7	1,381.4
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(329.0)	(329.0)	(329.0)	(329.0)	(329.0)	(658.0)	(658.0)	(658.0)	(658.0)	(658.0)	(658.0)	(658.0)
Municipal Tax - $k			(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)
Net Revenue/(Costs) before taxes - $k		0.0	49.6	153.9	397.4	476.9	561.4	326.8	406.3	480.9	535.5	570.3	595.2	634.9
Income Taxes - $k		0.0	211.0	389.6	290.7	237.9	186.4	221.8	176.0	133.6	98.2	69.8	45.5	18.7
Operating Cash Flow (after taxes) - $k		0.0	260.6	543.6	688.1	714.9	747.8	548.6	582.4	614.4	633.7	640.1	640.7	653.6
PV Operating Cash Flow (after taxes) - $k (A)	8,221.5	0.0	253.4	499.7	598.0	587.3	580.8	402.8	404.3	403.2	393.2	375.5	355.3	342.7
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(21,150.0)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(21,150.0)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(21,150.0)												
PV CCA Residual Tax Shield - $k		103.7												
PV Working Capital - $k		1.2												
PV Capital (after taxes) - $k (B)	(21,045.1)	(21,045.1)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(12,823.6)	(21,045.1)	(20,791.7)	(20,292.0)	(19,694.0)	(19,106.7)	(18,525.8)	(18,123.0)	(17,718.7)	(17,315.5)	(16,922.3)	(16,546.8)	(16,191.6)	(15,848.9)

	Mar-31 2032	Mar-31 2033	Mar-31 2034	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
Month / Year	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	58.6	60.1	61.1	62.5	63.6	65.0	66.0	67.4	68.5	69.9	70.9	72.4	73.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	58.6	60.1	61.1	62.5	63.6	65.0	66.0	67.4	68.5	69.9	70.9	72.4	73.0
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k	1,421.2	1,456.0	1,480.8	1,515.6	1,540.5	1,575.2	1,600.1	1,634.9	1,659.7	1,694.5	1,719.3	1,754.1	1,769.0
On-going OM&A Costs - $k	(658.0)	(658.0)	(658.0)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)
Municipal Tax - $k	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)	(88.5)
Net Revenue/(Costs) before taxes - $k	674.7	709.5	734.3	604.6	629.4	664.2	689.1	723.9	748.7	783.5	808.3	843.1	858.0
Income Taxes - $k	(6.8)	(29.7)	(49.0)	(26.3)	(43.6)	(62.6)	(78.3)	(95.9)	(110.1)	(126.4)	(139.5)	(154.7)	(164.1)
Operating Cash Flow (after taxes) - $k	667.9	679.7	685.3	578.3	585.9	601.6	610.8	628.0	638.6	657.1	668.8	688.4	693.9
PV Operating Cash Flow (after taxes) - $k (A)	331.0	318.5	303.6	242.2	231.9	225.2	216.1	210.1	202.0	196.5	189.1	184.0	175.3
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(15,517.9)	(15,199.4)	(14,895.8)	(14,653.6)	(14,421.7)	(14,196.5)	(13,980.4)	(13,770.3)	(13,568.4)	(13,371.9)	(13,182.9)	(12,998.9)	(12,823.6)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - %: 5.78%

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		16,035.7		16,035.7	
PV OM&A Costs		(7,945.9)		(7,945.9)	
PV Municipal Tax		(1,188.9)		(1,188.9)	
PV Income Taxes		(1,828.7)		(1,828.7)	
PV CCA Tax Shield		3,253.0		922.2	(2,330.9)
PV Capital - Upfront	(21,150.0)		(21,150.0)		
Add: PV Capital Contribution	0.0	(21,150.0)	15,154.5	(5,995.5)	15,154.5
PV Capital - On-going		0.0		0.0	
PV Working Capital		1.2		1.2	
PV Surplus / (Shortfall)		(12,823.6)		0.0	12,823.6
Profitability Index*		0.4		1.0	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatio	2019	15,154.5		15,154.5
Total		15,154.5	0.0	15,154.5
Contribution Required (before HST				15,154.5
HST @ 13%				1,970.1
Contribution Required (including HST				17,124.6

Notes:
1) Payment from customer must include HST.

Other Assumptions		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income tax
Ontario Corporation Income Ta	11.50%	2016 provincial corporate income tax
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 15-Aug-16, 4:20 PM

1

Project D21 – Enfield TS: Build 230/44kV Transformer Station

Date: 17-Aug-16
Project#

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - Estimated cost

hydro one

Facility Name: 2017/2018 TX Rate Case - Enfield TS: Build 230/44kV Transformer Station
Description: ISD# D21
Customer: OPUC

In-Service Date <------ Project year ended - annualized from In-Service Date -------->

	Month / Year	Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029	Mar-31 2030	Mar-31 2031
							1st true-up					2nd true-up		
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			55.3	62.6	70.1	77.7	85.6	93.7	100.8	104.0	104.0	104.0	104.0	104.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			55.3	62.6	70.1	77.7	85.6	93.7	100.8	104.0	104.0	104.0	104.0	104.0
Tariff Applied ($/kW/Month)			3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Incremental Revenue - $k			2,428.4	2,751.4	3,077.7	3,411.4	3,760.9	4,113.9	4,427.3	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(14.6)	(14.6)	(14.6)	(14.6)	(14.6)	(14.6)	(14.6)
Municipal Tax - $k			(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)
Net Revenue/(Costs) before taxes - $k		0.0	2,416.4	2,739.4	3,065.7	3,399.4	3,748.9	4,094.6	4,408.0	4,548.4	4,548.4	4,548.4	4,548.4	4,548.4
Income Taxes - $k		0.0	(628.4)	(703.0)	(791.3)	(881.5)	(975.6)	(1,068.7)	(1,153.0)	(1,191.4)	(1,192.5)	(1,193.6)	(1,194.5)	(1,195.4)
Operating Cash Flow (after taxes) - $k		0.0	1,788.0	2,036.4	2,274.3	2,518.0	2,773.3	3,025.9	3,255.0	3,357.0	3,355.8	3,354.8	3,353.9	3,353.0
	Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $k (A)	39,901.6	0.0	1,738.4	1,871.8	1,976.4	2,068.7	2,154.0	2,221.9	2,259.6	2,203.1	2,082.1	1,967.8	1,859.8	1,757.8
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(1,125.4)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(1,125.4)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(1,125.4)												
PV CCA Residual Tax Shield - $k		5.5												
PV Working Capital - $k		0.0												
PV Capital (after taxes) - $k (B)	(1,119.9)	(1,119.9)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	38,781.7	(1,119.9)	618.6	2,490.4	4,466.9	6,535.5	8,689.6	10,911.5	13,171.0	15,374.1	17,456.2	19,424.0	21,283.8	23,041.6

	Mar-31 2032	Mar-31 2033	Mar-31 2034	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
			3rd true-up										
	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Tariff Applied ($/kW/Month)	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Incremental Revenue - $k	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7	4,567.7
On-going OM&A Costs - $k	(14.6)	(14.6)	(14.6)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)
Municipal Tax - $k	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)
Net Revenue/(Costs) before taxes - $k	4,548.4	4,548.4	4,548.4	4,544.7	4,544.7	4,544.7	4,544.7	4,544.7	4,544.7	4,544.7	4,544.7	4,544.7	4,544.7
Income Taxes - $k	(1,196.2)	(1,196.9)	(1,197.6)	(1,197.2)	(1,197.8)	(1,198.3)	(1,198.8)	(1,199.3)	(1,199.7)	(1,200.0)	(1,200.4)	(1,200.7)	(1,201.0)
Operating Cash Flow (after taxes) - $k	3,352.2	3,351.5	3,350.8	3,347.5	3,346.9	3,346.4	3,345.9	3,345.5	3,345.1	3,344.7	3,344.4	3,344.0	3,343.8
PV Operating Cash Flow (after taxes) - $k (A)	1,661.4	1,570.3	1,484.3	1,401.9	1,325.1	1,252.5	1,183.9	1,119.1	1,057.9	1,000.0	945.3	893.6	844.7
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	24,703.0	26,273.4	27,757.7	29,159.5	30,484.6	31,737.1	32,921.0	34,040.2	35,098.1	36,098.1	37,043.4	37,937.0	38,781.7

Discounted Cash Flow Summary

Economic Study Horizon - Years		25
Discount Rate - %		5.78%
		$k
PV Incremental Revenue		54,299.2
PV OM&A Costs		(176.0)
PV Municipal Tax		(63.3)
PV Income Taxes		(14,325.9)
PV CCA Tax Shield		173.1
PV Capital - Upfront	(1,125.4)	
Add: PV Capital Contribution	0.0	(1,125.4)
PV Capital - On-going		0.0
PV Working Capital		0.0
PV Surplus / (Shortfall)		38,781.7
Profitability Index*		35.5

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42 %	Transmission system average
Federal Income Tax	15.00 %	2016 federal corporate income tax
Ontario Corporation Income Tax	11.50 %	2016 provincial corporate income tax
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8 %	100% Class 47 assets

Calculation Time Stamp: 17-Aug-16, 10:23 AM

Date :	17-Aug-16
Project#	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

hydro one

Facility Name:	2017/2018 TX Rate Case - Enfield TS: Build 230/44kV Transformer Station
Description:	ISD# D21
Customer:	OPUC

<-------- Project year ended - annualized from In-Service Date -------->

		In-Service Date Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029	Mar-31 2030	Mar-31 2031
	Month / Year						1st true-up					2nd true-up		
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			55.3	62.6	70.1	77.7	85.6	93.7	100.8	104.0	104.0	104.0	104.0	104.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			55.3	62.6	70.1	77.7	85.6	93.7	100.8	104.0	104.0	104.0	104.0	104.0
Tariff Applied ($/kW/Month)			2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k			1,340.2	1,518.5	1,698.6	1,882.8	2,075.7	2,270.5	2,443.5	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(223.7)	(223.7)	(223.7)	(223.7)	(223.7)	(447.4)	(447.4)	(447.4)	(447.4)	(447.4)	(447.4)	(447.4)
Municipal Tax - $k			(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)
Net Revenue/(Costs) before taxes - $k		0.0	1,027.0	1,205.3	1,385.4	1,569.6	1,762.5	1,733.6	1,906.6	1,984.0	1,984.0	1,984.0	1,984.0	1,984.0
Income Taxes - $k		0.0	(45.5)	115.8	33.2	(47.6)	(128.2)	(147.6)	(218.4)	(261.9)	(283.0)	(302.4)	(320.3)	(336.7)
Operating Cash Flow (after taxes) - $k		0.0	981.5	1,321.1	1,418.6	1,522.0	1,634.3	1,585.9	1,688.1	1,722.1	1,701.0	1,681.6	1,663.7	1,647.3
	Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $k (A)	20,355.9	0.0	954.3	1,214.4	1,232.8	1,250.4	1,269.4	1,164.5	1,171.9	1,130.2	1,055.4	986.4	922.6	863.6
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(21,382.6)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(21,382.6)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(21,382.6)												
PV CCA Residual Tax Shield - $k		104.9												
PV Working Capital - $k		0.8												
PV Capital (after taxes) - $k (B)	(21,276.9)	(21,276.9)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(921.0)	(21,276.9)	(20,322.6)	(19,108.2)	(17,875.4)	(16,625.0)	(15,355.6)	(14,191.1)	(13,019.2)	(11,889.0)	(10,833.6)	(9,847.3)	(8,924.7)	(8,061.1)

	Mar-31 2032	Mar-31 2033	Mar-31 2034	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
			3rd true-up										
	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0	2,521.0
On-going OM&A Costs - $k	(447.4)	(447.4)	(447.4)	(559.3)	(559.3)	(559.3)	(559.3)	(559.3)	(559.3)	(559.3)	(559.3)	(559.3)	(559.3)
Municipal Tax - $k	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)	(89.5)
Net Revenue/(Costs) before taxes - $k	1,984.0	1,984.0	1,984.0	1,872.2	1,872.2	1,872.2	1,872.2	1,872.2	1,872.2	1,872.2	1,872.2	1,872.2	1,872.2
Income Taxes - $k	(351.9)	(365.8)	(378.6)	(360.7)	(371.5)	(381.5)	(390.7)	(399.1)	(406.9)	(414.0)	(420.6)	(426.6)	(432.2)
Operating Cash Flow (after taxes) - $k	1,632.2	1,618.3	1,605.5	1,511.5	1,500.6	1,490.7	1,481.5	1,473.1	1,465.3	1,458.2	1,451.6	1,445.5	1,440.0
PV Operating Cash Flow (after taxes) - $k (A)	808.9	758.2	711.2	633.0	594.1	557.9	524.2	492.8	463.4	436.0	410.3	386.3	363.8
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(7,252.2)	(6,493.9)	(5,782.8)	(5,149.8)	(4,555.7)	(3,997.8)	(3,473.5)	(2,980.8)	(2,517.4)	(2,081.4)	(1,671.1)	(1,284.8)	(921.0)

Discounted Cash Flow Summary

Economic Study Horizon - Years	25	
Discount Rate - %	5.78%	

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		29,968.4		29,968.4	
PV OM&A Costs		(5,403.2)		(5,403.2)	
PV Municipal Tax		(1,202.0)		(1,202.0)	
PV Income Taxes		(6,191.3)		(6,191.3)	
PV CCA Tax Shield		3,288.8		3,121.4	(167.4)
PV Capital - Upfront	(21,382.6)		(21,382.6)		
Add: PV Capital Contribution	0.0	(21,382.6)	1,088.4	(20,294.2)	1,088.4
PV Capital - On-going		0.0		0.0	
PV Working Capital		0.8		0.8	
PV Surplus / (Shortfall)		(921.0)		0.0	921.0
Profitability Index*		1.0		1.0	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatio	2019	1,088.4		1,088.4
Total		1,088.4	0.0	1,088.4
Contribution Required (before HST				1,088.4
HST @ 13%				141.5
Contribution Required (including HST[1]				1,229.9

Notes:
1) Payment from customer must include HST.

Other Assumptions

		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income ta:
Ontario Corporation Income Ta	11.50%	2016 provincial corporate income ta:
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 17-Aug-16, 10:23 AM

1

Date: 17-Aug-16
Project#

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - Estimated cost

hydro one

Facility Name: 2017/2018 TX Rate Case - Enfield TS: Build 230/44kV Transformer Station
Description: ISD# D21
Customer: Hydro One DX

Month / Year	Cumulative PV @ 5.78%	In-Service Date Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024 (1st true-up)	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029 (2nd true-up)	Mar-31 2030	Mar-31 2031
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			40.9	45.2	45.9	46.6	47.3	47.9	48.6	49.0	49.0	49.0	49.0	49.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			40.9	45.2	45.9	46.6	47.3	47.9	48.6	49.0	49.0	49.0	49.0	49.0
Tariff Applied ($/kW/Month)			3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Incremental Revenue - $k			1,796.8	1,985.2	2,015.4	2,045.5	2,075.7	2,105.7	2,134.2	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(3.2)	(3.2)	(3.2)	(3.2)	(3.2)	(3.2)	(3.2)
Municipal Tax - $k			(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)
Net Revenue/(Costs) before taxes - $k		0.0	1,793.0	1,981.4	2,011.6	2,041.7	2,071.8	2,100.3	2,128.7	2,146.6	2,146.6	2,146.6	2,146.6	2,146.6
Income Taxes - $k		0.0	(469.5)	(514.3)	(523.1)	(531.9)	(540.6)	(548.8)	(557.0)	(562.3)	(562.8)	(563.3)	(563.8)	(564.2)
Operating Cash Flow (after taxes) - $k		0.0	1,323.5	1,467.1	1,488.4	1,509.8	1,531.2	1,551.4	1,571.7	1,584.3	1,583.8	1,583.3	1,582.9	1,582.5
PV Operating Cash Flow (after taxes) - $k (A)	20,677.9	0.0	1,286.8	1,348.6	1,293.5	1,240.4	1,189.3	1,139.2	1,091.1	1,039.7	982.6	928.7	877.7	829.6
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(529.6)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(529.6)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(529.6)												
PV CCA Residual Tax Shield - $k		2.6												
PV Working Capital - $k		0.0												
PV Capital (after taxes) - $k (B)	(527.0)	(527.0)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	20,150.9	(527.0)	759.8	2,108.4	3,401.8	4,642.2	5,831.5	6,970.7	8,061.7	9,101.5	10,084.1	11,012.8	11,890.6	12,720.1

Month / Year	Mar-31 2032	Mar-31 2033	Mar-31 2034 (3rd true-up)	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
Tariff Applied ($/kW/Month)	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Incremental Revenue - $k	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1	2,152.1
Removal Costs - $k													
On-going OM&A Costs - $k	(3.2)	(3.2)	(3.2)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Municipal Tax - $k	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)
Net Revenue/(Costs) before taxes - $k	2,146.6	2,146.6	2,146.6	2,145.8	2,145.8	2,145.8	2,145.8	2,145.8	2,145.8	2,145.8	2,145.8	2,145.8	2,145.8
Income Taxes - $k	(564.6)	(564.9)	(565.2)	(565.3)	(565.6)	(565.8)	(566.0)	(566.2)	(566.4)	(566.6)	(566.8)	(566.9)	(567.1)
Operating Cash Flow (after taxes) - $k	1,582.1	1,581.7	1,581.4	1,580.5	1,580.3	1,580.0	1,579.8	1,579.6	1,579.4	1,579.2	1,579.1	1,578.9	1,578.8
PV Operating Cash Flow (after taxes) - $k (A)	784.1	741.1	700.5	661.9	625.6	591.4	559.0	528.4	499.5	472.2	446.3	421.9	398.8
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	13,504.3	14,245.4	14,945.9	15,607.8	16,233.4	16,824.8	17,383.8	17,912.2	18,411.7	18,883.9	19,330.2	19,752.1	20,150.9

Discounted Cash Flow Summary

Economic Study Horizon - Years		25
Discount Rate - %		5.78%
		$k
PV Incremental Revenue		28,094.7
PV OM&A Costs		(39.0)
PV Municipal Tax		(29.8)
PV Income Taxes		(7,426.9)
PV CCA Tax Shield		81.5
PV Capital - Upfront	(529.6)	
Add: PV Capital Contribution	0.0	(529.6)
PV Capital - On-going		0.0
PV Working Capital		0.0
PV Surplus / (Shortfall)		20,150.9
Profitability Index*		39.0

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42 %	Transmission system average
Federal Income Tax	15.00 %	2016 federal corporate income tax
Ontario Corporation Income Tax	11.50 %	2016 provincial corporate income tax
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8 %	100% Class 47 assets

Calculation Time Stamp: 17-Aug-16, 10:23 AM

1

Date :	17-Aug-16
Project#	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Estimated cost

hydro one

Facility Name:	2017/2018 TX Rate Case - Enfield TS: Build 230/44kV Transformer Station
Description:	ISD# D21
Customer:	Hydro One DX

Project year ended - annualized from In-Service Date

		In-Service Date Mar-31 2019	Mar-31 2020	Mar-31 2021	Mar-31 2022	Mar-31 2023	Mar-31 2024 (1st true-up)	Mar-31 2025	Mar-31 2026	Mar-31 2027	Mar-31 2028	Mar-31 2029 (2nd true-up)	Mar-31 2030	Mar-31 2031
	Month / Year	0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			40.9	45.2	45.9	46.6	47.3	47.9	48.6	49.0	49.0	49.0	49.0	49.0
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			40.9	45.2	45.9	46.6	47.3	47.9	48.6	49.0	49.0	49.0	49.0	49.0
Tariff Applied ($/kW/Month)			2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k			991.7	1,095.6	1,112.3	1,129.0	1,145.6	1,162.2	1,177.9	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(105.3)	(105.3)	(105.3)	(105.3)	(105.3)	(210.6)	(210.6)	(210.6)	(210.6)	(210.6)	(210.6)	(210.6)
Municipal Tax - $k			(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)
Net Revenue/(Costs) before taxes - $k		0.0	844.3	948.3	964.9	981.6	998.2	909.5	925.2	935.1	935.1	935.1	935.1	935.1
Income Taxes - $k		0.0	(117.1)	(46.5)	(67.3)	(86.8)	(105.1)	(94.3)	(110.2)	(123.6)	(133.6)	(142.7)	(151.1)	(158.8)
Operating Cash Flow (after taxes) - $k		0.0	727.2	901.8	897.6	894.8	893.1	815.2	815.0	811.5	801.5	792.4	784.0	776.2
	Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $k (A)	10,610.5	0.0	707.1	828.9	780.1	735.1	693.7	598.6	565.8	532.5	497.3	464.8	434.7	406.9
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(10,062.4)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		(10,062.4)												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		(10,062.4)												
PV CCA Residual Tax Shield - $k		49.4												
PV Working Capital - $k		0.4												
PV Capital (after taxes) - $k (B)	(10,012.7)	(10,012.7)												
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	597.8	(10,012.7)	(9,305.6)	(8,476.7)	(7,696.6)	(6,961.5)	(6,267.8)	(5,669.2)	(5,103.5)	(4,570.9)	(4,073.6)	(3,608.8)	(3,174.1)	(2,767.1)

	Mar-31 2032	Mar-31 2033	Mar-31 2034 (3rd true-up)	Mar-31 2035	Mar-31 2036	Mar-31 2037	Mar-31 2038	Mar-31 2039	Mar-31 2040	Mar-31 2041	Mar-31 2042	Mar-31 2043	Mar-31 2044
	13	14	15	16	17	18	19	20	21	22	23	24	25
Load Forecast (MW)	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8	1,187.8
On-going OM&A Costs - $k	(210.6)	(210.6)	(210.6)	(263.2)	(263.2)	(263.2)	(263.2)	(263.2)	(263.2)	(263.2)	(263.2)	(263.2)	(263.2)
Municipal Tax - $k	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)	(42.1)
Net Revenue/(Costs) before taxes - $k	935.1	935.1	935.1	882.4	882.4	882.4	882.4	882.4	882.4	882.4	882.4	882.4	882.4
Income Taxes - $k	(166.0)	(172.5)	(178.5)	(170.1)	(175.2)	(179.9)	(184.2)	(188.2)	(191.8)	(195.2)	(198.3)	(201.1)	(203.8)
Operating Cash Flow (after taxes) - $k	769.1	762.6	756.6	712.3	707.2	702.5	698.2	694.3	690.6	687.2	684.2	681.3	678.7
PV Operating Cash Flow (after taxes) - $k (A)	381.2	357.3	335.1	298.3	280.0	263.0	247.1	232.2	218.4	205.5	193.4	182.1	171.5
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k (A)+(B)	(2,386.0)	(2,028.6)	(1,693.5)	(1,395.2)	(1,115.2)	(852.3)	(605.2)	(373.0)	(154.6)	50.9	244.3	426.4	597.8

Discounted Cash Flow Summary

Economic Study Horizon - Years		25
Discount Rate - %		5.78%
		$k
PV Incremental Revenue		15,505.8
PV OM&A Costs		(2,542.7)
PV Municipal Tax		(565.6)
PV Income Taxes		(3,285.3)
PV CCA Tax Shield		1,547.7
PV Capital - Upfront	(10,062.4)	
Add: PV Capital Contribution	0.0	(10,062.4)
PV Capital - On-going		0.0
PV Working Capital		0.4
PV Surplus / (Shortfall)		597.8
Profitability Index*		1.1

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions		Notes:
In-Service Date	31-Mar-19	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	2016 federal corporate income tax
Ontario Corporation Income Tax	11.50%	2016 provincial corporate income tax
Working cash net lag days	-1.04	As Per Lead Lag study prepared by Navigant for 2015 and 2016 Transmission
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 17-Aug-16, 10:23 AM

1

Ontario Energy Board (Board Staff) INTERROGATORY #075

Reference:

Exhibit B1/Tab3/ Sch 10 p. 1

Interrogatory:

This section of the application acknowledges that in April 2010 the OEB had accepted a methodology proposed by Black & Vetch (BV) that derived an overhead capitalization rate for Hydro One Distribution's common corporate costs. This accepted methodology was used in the 2013-14 and 2015-16 transmission rate applications. Hydro One indicates that this methodology continues to be a reasonable method of distributing common corporate costs to capital projects for transmission rates in 2017-2018.

a) Please file a copy of the review of capitalization filed in the EB-2012-0031 proceeding.

b) Please outline the analysis that Hydro One undertook to support its statement of the continued reasonableness of the BV methodology?

c) How would the nature and quantum of the costs being capitalized under the current methodology be impacted if the capitalization guidance prescribed by IAS 16 was followed?

Response:

a) Attached please find a copy of the review of capitalization filed in the EB-2012-0031 proceeding.

b) The methodology review has been undertaken by Black & Veatch to assess the reasonableness and conformity to the OEB-accepted methodology. As stated in the instructions provided to Black & Veatch, which can be seen on page 15 of Exhibit B1-3-10, Attachment 1 and as stated in the expert evidence statement, which can be found on page 16 of Exhibit B1-3-10, Attachment 1, a review and update of the accepted methodology has been done as part of this study.

c) It is expected that under IAS 16 total capitalization on a consolidated basis at the Hydro One Limited level would decrease by approximately $310 million.

Hydro One Networks Inc.

Transmission Business – Review of Overhead Capitalization Policy

April 14, 2012

Executive Summary

In its EB-2011-0268 decision, the Ontario Energy Board (OEB or Board) granted Hydro One Networks Inc. (Hydro One, Networks or the Company) approval to adopt United States (US) generally accepted accounting principles (GAAP) in place of modified International Financial Reporting Standards (IFRS) as its approved basis for regulatory accounting and reporting.

In its decision, the Board considered it appropriate to require Networks "to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

The following report has been developed to document the results of Hydro One's review of the appropriateness of its capitalization accounting policy for overhead and indirect costs. The Company's review incorporated a study of accounting theory under the various GAAP frameworks, a review of regulatory guidance in North America and a comparison between Hydro One's practices and those of other North American utilities.

The study approach incorporated the following steps:

1. A review of Hydro One's legacy accounting policy and the rationale for it;
2. A review of the GAAP environment governing overhead/indirect cost capitalization;
3. A review of North American regulatory principles and related guidance;
4. An assessment of the of Hydro One's approach in light of steps 2 and 3 above;
5. Conducting industry research; and
6. Conclusion

Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in the Company's industry research of other Canadian and US utilities.

This information is summarized in the following table.

Overhead Capitalization Rate (as a percentage of gross operating costs*)			
Hydro One	**Canadian Utilities****	**U.S. Utilities****	**Analysis**
Transmission (2013) - 20%	Industry Median*** - 19%	Industry Median**** - 19%	• The range of overhead capitalization rates varies across the utilities in Canada and US. For Canadian utilities it ranges from 5% to 35.6% with an observed median of 19%. For U.S. utilities, it ranges from 7.33% to >50% with an observed median of 19%. • The rates are based on legacy Canadian GAAP for Canadian utilities and US GAAP for US utilities. However, both accounting frameworks are substantively the same in this area.

* *Gross operating costs include capitalized overheads added back.*
** *Refer Appendix A for a list of the Canadian and U.S. utilities researched and summary of findings.*
*** *Median represents middle value of the range of overhead capitalization rates for those utilities selected for research and where rate information was available.*
**** *The US median is based on a concentration of three results in the 19% range, with one individual outlier at ~7% and another >50%.*

In addition to the rate findings, industry research clearly shows that the capitalization of general and administrative overhead costs is accepted practice.

The key findings of the Company's policy review were:

1. In prior years, Hydro One has capitalized an appropriate proportion of overhead and indirect corporate support expenditures based on a consistently applied, rational and systematic model based on causality. No changes in Hydro One's methodology are proposed with the adoption of US GAAP.

2. Legacy Canadian and US GAAP both allow for the capitalization of attributable indirect costs and overheads, while IFRS specifically prohibits the capitalization of several categories of such expenditures.

3. Canadian, and more particularly US regulatory guidance, supports the capitalization of attributable overheads based on a cost causality model.

4. Hydro One capitalizes an appropriate proportion of its indirect and overhead support expenditures, consistent with GAAP and regulatory guidance.

5. Hydro One's practice, both in terms of the types and proportion of overhead and indirect expenditures capitalized, is generally consistent with the practices of many other large North American transmitters and other rate regulated utilities.

6. Hydro One's cost capitalization policy with respect to overheads and indirect costs is an appropriate one for use in a US GAAP regulatory environment.

Introduction - Overview of the Study

In its EB-2011-0268 decision, the Board granted Networks approval to adopt US GAAP instead of modified IFRS for regulatory accounting and reporting purposes. The OEB generally accepted Hydro One's position that adopting US GAAP would result in benefits both to its customers and to its shareholder. In addition, in response to intervenor assertions that Hydro One's capitalization practices had been "aggressive" under legacy Canadian GAAP, the OEB also considered "it appropriate to require Hydro One to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

In its decision with reasons on EB-2011-0268, the OEB noted that the reduction in revenue requirement, and intervenor support for it, was a significant argument in favour of retaining the Company's legacy cost capitalization policy for Networks' Transmission Business. Hydro One's cost capitalization policy was developed under legacy Canadian GAAP, where it has been subjected to external audit since inception of the company. The Company believes that It continues to be an appropriate policy under US GAAP. Such a policy was not allowable under the constraining cost capitalization rules found within IFRS, most particularly in IAS 16 "Property, Plant and Equipment."

Specifically, significant differences in accounting exist between US and legacy Canadian GAAP on one side, and IFRS on the other, with respect to the indirect and general and administrative overhead expenditures that qualify for capitalization. A measure of the magnitude of the revenue requirement impact of the different accounting frameworks can be seen in the $200 million adjustment required to reflect the Board's EB-2011-0268 Transmission decision that authorized the Company's use of US GAAP for regulatory purposes.

In response to the Board's direction, Hydro One has performed a critical review of the theoretical appropriateness of its accounting policies governing the capitalization of overhead and indirect costs. This review focused on: a review of the conformance of its legacy Canadian and continuing US GAAP capitalization policy with GAAP; consistency with regulatory principles and guidance; and a comparison with the practices of other major US and Canadian utilities. These comparable utilities include both transmitters and large distributors, including some within Ontario. The latter were included as it was determined early on in the study that the Board would likely require an extension of the scope of the transmission analysis to distributors given that Networks had also requested an exception to adopt US GAAP for its Distribution Business as well. On March 23, 2012, the Board approved Networks' request in respect of its Distribution Business (EB-2011-0399) as well. A similar request was made in that decision to conduct a Distribution Business cost capitalization study. However, given the requirement to compare to other Ontario local distribution companies that are using modified IFRS as a basis for their external reporting and rate setting, the scope of that report is likely to be somewhat different than this one.

The Company determined that it was appropriate to extend of the scope of its research to include large Canadian distributors as finding detailed information on US practice was quite difficult. Inclusion of other Canadian entities expands the pool of comparable utilities. In addition, a recent surge in the numbers of Canadian utilities seeking approval to adopt US GAAP in place of IFRS has led to increased informal information sharing and greater availability of information in Canada.

The critical review requested by the Board has been conducted in two main parts. The first part was a review of the origin and continued appropriateness of Hydro One's cost capitalization accounting policies under GAAP and under regulatory principles and guidance. The second element of the study was a comparison to the practices of other major North American rate regulated utilities. As noted in the Board's request, this was not intended to be a comprehensive benchmarking study. Instead, it was treated as an intelligence gathering activity aimed at gathering useful information on what types and amounts of indirect and overhead costs other utilities capitalize.

The general approach adopted to fulfill the Board's request is described below:

1. Review Hydro One's Legacy Accounting

Hydro One's existing cost capitalization policies and the underlying rationale for them were evaluated and are summarized herein.

2. Summarize GAAP

The indirect and overhead cost capitalization requirements of competing GAAP frameworks were evaluated and are summarized herein.

3. Summarize Regulatory Guidance

Specific regulatory guidance was gathered and summarized and underlying regulatory principles governing cost capitalization were identified and are discussed herein.

4. Assess Theoretical Appropriateness of Hydro One's Approach

Hydro One assessed the degree of conformity between its cost capitalization practices and the requirements of GAAP and objectives of regulatory principles.

5. Conduct Industry Research

Hydro One gathered information on the overhead capitalization practices of selected major North American utilities. The objective of this research was to determine to what extent Hydro One's indirect cost and overhead capitalization approach conforms to generally accepted utilities practice and to what extent it can be deemed "aggressive" compared to its peers.

6. Conclusion

Hydro One reviewed the conclusions from step 4 above and the comparable information from step 5 to conclude on the reasonableness of continuing to apply its legacy Canadian GAAP approach to its US GAAP rate setting.

1. Review Hydro One's Legacy Accounting

Key findings: Hydro One has capitalized an appropriate proportion of overhead and indirect corporate support expenditures based on a consistently applied rational and systematic cost causality model.

Hydro One has two primary accounting policies that govern the capitalization of expenditures for each of its legal subsidiaries and regulated businesses. The policy that governs the classification of expenditures between capital and operation, maintenance and administration (OM&A) is SP 0775 R0 "Classification of Expenditures." This policy has not been significantly adjusted since demerger from Ontario Hydro in 1999 and the guidance included within it has been applied consistently in determining the rate base and revenue requirement for each of Hydro One's regulated subsidiaries and businesses. The policy has also been consistently reflected in developing Hydro One Transmission's audited financial statements.

The second applicable policy is SP 0804 R0 "Shared Corporate Services Cost Allocation and Transfer Pricing Policy," which outlines the principles to be used in allocating shared corporate functions and services costs. This policy provides guidance on the allocation of shared services costs, requiring that they be assigned to affiliates based on the principle of cost-causation.

General capitalization approach

Hydro One provides detailed policy guidance on whether expenditures incurred in a given accounting period should be recorded in the Statement of Operations as an expense of that period, or included as an asset on the Balance Sheet. For regulatory purposes, the consequence of this decision is either inclusion in current period revenue requirement or in the rate base. The overriding criteria applied in determining the appropriate accounting treatment of an expenditure is whether or not it meets the definition of an asset under GAAP. In almost all cases, the regulatory treatment parallels the GAAP classification.

To determine whether an expenditure represents and an expense of the period or an asset with future economic benefit, the GAAP principle of "matching" is applied. The definition of an asset under US GAAP is found in Financial Accounting Standards Board (FASB) Statement of Financial Accounting Concepts (SFAS) No. 6 "Elements of Financial Statements." Under this concepts standard, an asset consists of "probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events." In addition, "an asset has three essential characteristics: (a) it embodies a probable future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cash inflows, (b) a particular entity can obtain the benefit and control others' access to it, and (c) the transaction or other event giving rise to the entity's right to or control of the benefit has already occurred." This definition is virtually identical to that found in the parallel accounting standard in legacy Canadian GAAP. This is found in section 1000 "Financial Statement Concepts" in Part V of the Handbook of the Canadian Institute of Chartered Accountants.

Asset recognition of those expenditures that will probably result in future economic benefits is a foundational concept in accrual accounting. Accrual accounting requires that the relationship between an expense and a revenue item be evaluated and, where there is a direct relationship, that the timing of expense recognition be matched to the recognition of that future related revenue. This assessment requires that the strength and nature of the relationship between expenditures and resultant future benefits be evaluated. This is accomplished by using professional judgment to determine whether a causality and/or beneficial relationship exists between them. In a rate regulated environment, any assessment of future benefits resulting from expenditures will also include in an assessment of whether the expenditure provides operational or service benefits to future customers. This also requires some assessment of whether the expenditure is caused by, or benefits future customer generations.

Hydro One's Classification of Expenditures Policy

Hydro One's Classification of Expenditures Policy is one of the company's most important and often referenced accounting policies. In general, it provides general and specific guidance on the types of expenditures that qualify as assets, defines capitalization terms, provides dollar capitalization thresholds for projects and provides specific decision rules for certain types of transactions.

Under the policy, expenditures incurred for the following general purposes are eligible for capitalization, when above established materiality limits:

- purchase, construction and commissioning of specific assets;
- design and development of specific assets;
- additions of new or replacement components for existing assets; and
- betterments that result in increases in: productive capacity or output; efficiency; useful life span over original specification; or economy of operation.

The Classification of Expenditures Policy requires that the following types of expenditures qualify for capitalization: direct labour; direct materials and supplies; transportation costs; directly attributable external costs; fees; permits; indirect expenditures (including financing costs and attributable shared functions and services costs including general engineering, administrative salaries and expenses), and attributable indirect depreciation of equipment, tools and transport and work equipment.

While the policy does not specifically determine which overhead and indirect costs may be capitalized, it does provide the overall framework for the definition of an asset.

Hydro One's Shared Corporate Services Cost Allocation and Transfer Pricing Policy

This policy governs the allocation of shared asset and corporate functions and services costs between Hydro One's various subsidiaries and regulated businesses. For Networks, the policy also governs the allocation of shared asset management costs between the Transmission and Distribution businesses. The policy is important to ensure that the risk of cross subsidization between regulated and unregulated entities, and between different regulated businesses, is minimized. The policy also provides guidance on the acceptable basis of transfer pricing between entities, essentially reflecting the guidance found within the Board's Affiliate Relationships Code.

Shared corporate services include the provision of shared strategic management, policy and functional support to the subsidiaries and businesses of the parent entity. The rationale for sharing such costs is that it is economically more efficient to locate them centrally and share them based on causality and benefit than to replicate them within each affiliate. Shared costs relate to the provision of such shared services as: legal; regulatory; procurement; building and real estate support; information management and technology; corporate administration, finance, tax, treasury, pension, risk management, audit, planning, human resources, health and safety, communications, investor relations, trustee, and public affairs.

The same causality and benefit principles that are used to drive the allocation of shared corporate support expenditures and shared asset costs are also used to determine the appropriate classification of indirect and overhead expenditures between capital and OM&A.

The corporate cost allocation methodology requires that expenditures that can reasonably be specifically identified with a specific affiliate (i.e. subsidiary or regulated business) be allocated to that affiliate on a direct cost basis. However, most shared corporate functions and services costs cannot be directly associated with a specific affiliate and are therefore not treated as a direct charge. Shared corporate services costs that are not directly attributed must be allocated to the receiving affiliate using a rational and systematic mechanism. In general, cost drivers are used to achieve this goal. The driver to be used in allocating each shared cost should be the most appropriate based on the principle of cost causality. Causality exists when the incurrence of the shared cost is due to the business requirements of the affiliate. The Company must evaluate whether the cost would have been incurred had the affiliate's requirements not caused it? In cases where a causal relationship cannot be identified, but where the affiliate benefits from the shared service, a cost driver is selected that instead reflects the principle of cost benefit. In this case, the objective is to determine the proportion of total benefits provided by the shared service is enjoyed by the affiliate. Where a shared staff time study is deemed to be the most appropriate cost driver, such a time study is periodically updated to provide relevant information and evidence of causality and benefit.

Hydro One's methodology is reviewed internally on an annual basis and is independently reviewed periodically by an expert consultant for continued appropriateness of assumptions such as drivers. A full description of the cost allocation methodology as reviewed by Black and Veatch can be found in their report. Specific cost drivers and allocation rates are updated by Hydro One on an annual basis. All changes in direct and indirect costs, the allocation methodology, or cost drivers/allocators are appropriately documented.

Accurate allocation is necessary to ensure that, to the extent possible, customers of specific regulated utilities are paying for the cost of providing that utility's service. In addition, accurate and principle-based allocation ensures that the risk of cross subsidization between regulated and unregulated affiliates is minimized. Use of fully-allocated cost-based pricing ensures that inter-affiliate transfers comply with both the letter and the spirit of the Board's Affiliate Relationships Code. This code requires that affiliate transfers generally occur at fair value or, where such a value cannot reasonably be ascertained, at fully allocated cost taken as a proxy for fair value. Under Hydro One's accounting policy for cost allocation and transfer pricing, the inter-affiliate transfer of shared corporate services occurs at a fully allocated transfer price that retains the fair value proxy concept. This is because it incorporates the same general cost components that would be charged by an external service provider or vendor.

Summary of Hydro One's Overhead Capitalization Methodology

Hydro One uses the same general methodology and principles that it uses to allocate shared costs to affiliate entities when it classifies expenditures between current period expense and capital. The rationale for this is that the principles of causality and benefit are equally relevant for developing a robust and defensible assignment of cost responsibility between current and future customer generation. The objective of avoiding cross subsidization is the same as faced in allocating costs between entities. However, in the case of accounting classification the issue is avoiding having different generations (i.e. years) of customers cross subsidize each other. Customers should generally pay the costs that they cause or receive benefits from. Hydro One's accounting policies and practices have aimed at maintaining this objective to the extent possible while still adhering to the requirements of GAAP.

Hydro One's overhead capitalization methodology, similar to its allocation methodology, is subject to periodic external review by an independent consultant (currently Black and Veatch). The overhead capitalization methodology currently proposed for use by Hydro One Transmission develops separate capitalization rates within each affiliate, after shared costs have been fully allocated. To ensure that only those costs that benefit future customer generations get capitalized as part of the acquisition cost of fixed and intangible assets, Hydro One's methodology first screens allocated costs for whether or not they contribute to such assets. Certain expenditure types that are clearly not causally or beneficially linked to the acquisition of assets are removed from the overhead capitalization pool and disqualified from potential capitalization. This occurs as a first step in developing the capitalization rate. Secondly, if allocated shared costs can be associated with capital programs or projects, such costs are directly assigned to the pool of capitalizable expenditures even if they are not directly charged. Thirdly, a causality and benefit-based model is used to develop the capitalization rate. This rate is revisited through the year and adjusted as required to ensure that in-year variances are trued-up appropriately as underlying factors change.

Hydro One's methodology is based on the following principles:

- Regulatory Precedent – The shared service allocation methodology was initially developed with the assistance of Black and Veatch (then Rudden Associates) and was first documented in their 2005 "Report on Common Corporate Costs Methodology Review," which was accepted by the Board. Prior to the introduction of this independent review, Hydro One had carried out its own causality-based overhead allocation for its transitional rate orders for 1999 and 2000 rate years. The Black and Veatch report explicitly shows that the allocation and capitalization methodologies in use are based on cost causality and benefit principles. The current cost allocation methodology is consistent with that sued in prior years under legacy Canadian GAAP and is appropriate for use in a US GAAP environment. The use of direct assignments and cost drivers conforms to best practice.

- Cost Causation - The allocation methodology is reflective of the cost required to provide the shared services to affiliates. Shared service costs are allocated to each affiliate based on direct assignment where possible or based on activity cost drivers or time studies when not. The use of cost drivers conforms with the principle of direct attribution found in GAAP, as well as the regulatory principle of intergenerational equity.

- Supportive Methodology - The approach is supported by a defined and documented methodology that is subject to constant update. In addition, the approach is reviewed by, and reported on by an independent external consultant (Black and Veatch) on a recurring basis. In general, Black and Veatch reviews and reports on Hydro One's methodology in advance of major cost of service rate applications. Cost allocations and capitalization rates are updated annually by Hydro One as part of the business planning process. The current methodology is well understood by the subsidiaries and business units to which costs are distributed as well as estimators and project managers who are accountable for determining the cost of capital projects and programs. In addition, the current methodology is integrated with Hydro One's annual business planning process, thus producing reasonable and stable results over time.

2. Summarize GAAP

Key findings: Legacy Canadian and US GAAP both allow for the capitalization of attributable overheads while IFRS provide specific prohibitions that restrict the capitalization of several categories of such expenditures.

To evaluate the appropriateness of Hydro One's cost capitalization policy for indirect and overhead costs, it is useful to review the specific guidance found in the applicable accounting standards under each of the three relevant accounting frameworks: legacy Canadian GAAP; US GAAP and IFRS. More specifically, these are:

1. Legacy Canadian GAAP as defined by Part V of the Handbook of the Canadian Institute of Chartered Accountants;

2. US GAAP as defined by the Accounting Standards Codification (ASC) of the FASB; and
3. Current Canadian GAAP or IFRS as defined by Part I of the Handbook of the Canadian Institute of Chartered Accountants (CICA).

With respect to overhead accounting, it is necessary to understand that the concept of developing and applying overhead rates is a management accounting tool rather than a financial accounting activity. As a result, there is very limited explicit guidance in the financial accounting pronouncements of the three major accounting bodies.

1. Legacy Canadian GAAP

Financial Accounting

Guidance on the capitalization of expenditures under legacy Canadian GAAP is primarily found in section 3061 "Property, Plant and Equipment." Section 3061.16 indicates that property plant and equipment assets should be recorded at cost and provides guidance on the types of costs that qualify for capitalization. Section 3061.05 states that the cost of asset is " the amount of consideration given up to acquire, construct, develop or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset."

A major difference between section 3061 and the comparable IFRS standard (discussed in further detail below), is that the Canadian standard does not specifically bar the capitalization of indirect cost categories such as "general and administrative overheads" or "training costs."

Per paragraph 20 of the CICA standard, "the cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity." No definition of the term "directly attributable" is provided in the standard, resulting in the need for management to exercise its professional judgement in assessing the degree of direct attribution that exists.

For rate regulated entities, paragraph 10 of the section provides criteria for assessing whether or not an entity's assets qualify as rate-regulated property, plant and equipment. Each of Hydro One's rate regulated subsidiaries, including Hydro One Networks' Transmission Business, meets these criteria. Meeting the rate regulated definition is important as it allows for a different method of capitalizing financing costs than that that would be used by an unregulated entity. Specifically, a qualifying enterprise may capitalize the rate regulator's allowance for funds used during construction, even if it includes a cost of equity component. In addition, assets that meet these criteria may be costed in accordance with regulatory guidance from a qualifying rate regulator, which may differ from the generally accepted basis of costing in use by non-rate regulated enterprises.

Management Accounting

Certified Management Accountants of Canada has developed and released guidance on certain general management accounting practices (MAPs), including overhead accounting. The applicable document is MAP-2400 “Indirect Costs.” The relevant overhead accounting document discusses the issues related to designing costing systems for indirect costs. However, it is important to note that this MAP does not represent a primary source of financial accounting guidance within the formal legacy Canadian GAAP hierarchy. The purpose of this MAP is to discuss the issues related to designing management costing systems for indirect costs. Indirect costs are of all functional types, including administrative, manufacturing, logistical, and marketing. The issues related to handling indirect costs are general and independent of the functional nature of the cost. Hydro One’s capitalization model complies with the indirect cost pool design recommended by MAP-2400. Since cost allocation forms an integral part of Hydro One’s financial accounting capitalization model, it is appropriate that it is consistent with the approach for indirect cost allocation described below.

The MAP notes that when costs are used in contractual settings, such as in cost reimbursement contracts, insurance settlements, or transfer pricing where the price is based on cost, the criterion used to judge the adequacy of the costing system is whether its design could be reasonably expected to avoid material cost distortions in handling indirect costs. When various cost centers provide a significant level of services to themselves and to each other, the design of the costing system should reflect these interactions.

In general, the approach for designing the system of indirect cost pools should have the following steps:

- Classify the cost as direct or indirect;
- Determine if the cost is directly attributable to the cost object and assign it to the object to which it belongs if it is;
- Assign the cost to an appropriate indirect cost pool if it is indirect; and
- Choose an appropriate allocation basis for each indirect cost pool to assign the indirect costs in that pool to the final cost object.

MAP 2800 “Cost Allocation Rates” describes issues in the development and application of cost allocation bases or objects. The allocation of indirect costs to cost objects represents one of the most challenging tasks facing management accountants. This MAP identifies circumstances where care in allocating indirect costs is particularly important and it notes that ultimately the appropriate cost allocation should reflect the nature and purpose of the exercise.

An indirect cost that is allocated to a cost object should reflect that cost object’s use of the capacity resource to which the cost relates (effectively cost causality). As all cost allocations are by their nature subject to some degree of arbitrariness, the key is to develop a cost allocation which reasonably reflects the cause and effect relationship between resource use and resource cost.

MAP 6120 “Transfer Pricing in Regulated Environments” focuses on the pricing of transfers of goods or services in a regulated environment where goods or services are transferred between affiliates. Consistent with the requirements of the Board’s Affiliate Relationships Code and Hydro One’s relevant transfer pricing accounting policy described above, this MAP refers to full cost as an appropriate pricing method for such affiliate transactions in absence of market based pricing.

In general, the MAPs provide technical guidance to ensure some theoretical consistency between entities and consistent professional standards in management accounting and pricing. In general, management accounting concepts are common to various jurisdictions irrespective of which financial accounting framework applies. While management accounting is an internally focused activity, management accounting decisions and practices have real impacts on an entity’s financial accounting and financial statements.

2. US GAAP

As approved by the Board in its EB-2011-0268 decision, Hydro One Transmission has adopted US GAAP for rate-setting purposes effective January 1, 2012. Also, as noted by Hydro One in its application to adopt US GAAP as its basis for regulatory accounting and reporting, there are very few differences between legacy Canadian GAAP and existing US GAAP. Most of these differences relate to Balance sheet disclosure and presentation.

There is no formal standard within the body of documentation that represents US GAAP that provides comprehensive accounting guidance on the topic of property, plant and equipment. FASB’s ASC 360 “Property, Plant and Equipment” would appear to provide this but on closer inspection it is an aggregation of pre-codification standards dealing with specific capital accounting issues such as the capitalization of financing costs, business combinations, leases and industry-specific issues. It does not provide a complete accounting framework for fixed assets.

ASC 360 does define the cost of acquiring an asset. The historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use. The term “activities” necessary to bring an asset to the condition and location necessary for its intended use is to be construed broadly, encompassing physical construction of the asset, as well as all the steps required to prepare the asset for its intended use. For example, cost includes administrative and technical activities during the preconstruction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labour disputes, or litigation. The standard does not provide specific guidance that limits the types of expenditures or costs that qualify for capitalization.

In 2003, the American Institute of Certified Professional Accountants (AICPA) exposed a draft Statement of Position (SOP) on “Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment.” This was a proposed comprehensive standard intended to be issued before all standard setting accountability was later assigned to the FASB. The objective of the draft SOP was to replace the set of traditions and conventions that then made up US GAAP for property, plant, and equipment. The SOP proposed one consistent set of rules covering which costs that could be capitalized, either as part of the initial acquisition or construction of an asset, or during the asset's useful life. This resulted in a draft standard that was very close in content to the current IFRS accounting standard for property, plant and equipment.

The draft proposed to limit the categories of costs that could be capitalized to those that were "directly related." However, for the purposes of the proposed standard, "directly related" costs were interpreted as incremental direct costs, thus excluding indirect costs such as general and administrative overheads from capitalization. It specifically listed costs like executive management, corporate accounting, corporate legal, office management, human resource and marketing as indirect costs that would be ineligible for capitalization acquisition costs of capital assets. Respondents from capital intensive industries, including rate regulated utilities, were strongly opposed to the incremental cost capitalization principle include in the proposed SOP. Respondents found that a more appropriate method of costing capital assets was a full cost basis that includes direct costs and a reasonable attribution of indirect costs including general and administrative overheads. The incremental costing proposal was the primary reason why the exposure draft did not receive wide enough support to be adopted. As a result, the project was abandoned by the AICPA and not picked up as part of the FASB's go-forward work agenda. The abandonment of this project, based on a rejection of the incremental costing model, provides solid evidence that US users were not willing to accept the loss of their ability to capitalize general and administrative overheads. The practice of capitalizing such expenditures remains GAAP in the US to this day.

ASC 980 "Regulated Operations" provides the detailed guidance on accounting for rate regulated operations and the recognition of regulatory assets and liabilities that previously resided in SFAS 71 "Accounting for the Effects of Certain Types of regulation." SFAS 71 was the primary source of guidance under both US and legacy Canadian GAAP for guidance on rate regulated accounting matters. The effect is identical to that described above under Canadian GAAP, which is not surprising given that Canadian entities that were applying legacy Canadian GAAP looked to SFAS 71 in their application of regulatory accounting.

3. IFRS

Unlike US GAAP, IFRS provides very detailed and directive accounting guidance for property, plant and equipment in statement IAS 16. In addition, the IFRS framework has certain differences from those that underlay legacy CGAAP and US GAAP. For example, IFRS does not include a matching principle. Moreover, IFRS does not include any accounting recognition of the effects of rate regulation.

IAS 16 generally restricts capitalization of expenditures to those that are directly attributable to the construction or development of an asset. However, similar to the abandoned AICPA proposal in US GAAP, IAS 16 specifically prohibits the capitalization of certain expenditure categories like general and administrative overheads and training costs, even if a directly attributable argument can be made. A strong causal relationship is not sufficient to support capitalization given these prohibitions.

IFRS does not just have the effect of prohibiting the capitalization of general and administrative overheads. It also restricts the capitalization of other indirect expenditures where a "directly attributable" relationship cannot be demonstrated sufficiently to conform to international practice. For example, many indirect management and supervisory expenditures are not eligible for capitalization because they cannot be associated with a specific asset, not because they are unrelated to a capital work program. In Hydro One's EB-2010-0002 application, the adoption of IFRS had the impact of reclassifying, from capital to OM&A, about $200 million per annum of various categories of overhead and indirect expenditures.

It is well known that IFRS does not deal with the generic issue of rate regulated accounting. The IASB has struggled to finalize its rate regulated accounting project over the last few years and has yet to produce a useful accounting standard to deal with the rate regulated accounting issue. This topic is still on its work plan. In addition, it is clear that the specific IFRS standards that have been issued were not designed to achieve regulatory objectives.

3. Summarize Regulatory Guidance

Key findings: Canadian, and more particularly US regulatory guidance, supports the capitalization of attributable corporate support costs based on a cost causality model.

Canadian Regulatory Guidance

The Board has very recently revised its Accounting Procedures Handbook (APH) for Electricity Distribution Utilities to provide guidance to Ontario local distribution companies using modified IFRS as their approved basis for rate setting. The previous version of the APH provided guidance to utilities that had their rates set under legacy Canadian GAAP. In general, that APH required that regulatory accounting and reporting was based on legacy Canadian GAAP as is currently found in Part V of the CICA Handbook.

Article 410 provided that "property, plant and equipment should be recorded at cost, which includes the purchase price and other acquisition costs such as: option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges."

Article 230 defined the components of construction cost. Specifically, "the cost of construction properly included in the electric plant accounts shall include where applicable, the cost of labour; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other similar items as may be properly included in construction costs."

The previous legacy Canadian GAAP APH provided recognition that many of the categories of expenditures included in Hydro One's capital overhead rate do potentially qualify for capitalization, consistent with the general guidance found in legacy Canadian GAAP.

US Regulatory Guidance

The US Federal Energy Regulatory Commission (FERC) provides guidance that ensures consistency in accounting and reporting among US utilities. The FERC Uniform System of Accounts (USoA) is a key part of this accounting and reporting structure. The FERC provides guidelines for use by utilities in the US, including guidance on "overhead construction costs." The FERC's USoA guidance is provided under the overall framework of US GAAP.

- All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

- As far as practicable, the determination of payroll charges included in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

- For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

In addition, per FERC guidelines, allowable components of construction costs also include:

- Engineering and supervision - This includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.

- General administration - This includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.

- Engineering services – This includes the amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

While these cost elements are generally consistent with cost components included as capital by Hydro One under both legacy CGAAP and US GAAP, it is useful to note that many of these types of costs do not qualify for capitalization under IFRS IAS 16.

4. Assess Theoretical Appropriateness of Hydro One's Approach

Key findings: Hydro One capitalizes an appropriate proportion of its indirect and overhead support expenditures consistent with GAAP and formal regulatory guidance.

Overheads and indirect expenditures that relate to capital projects are those that are not directly charged to a capital program or project. While the expenditures may be causally or beneficially attributable to the capital project in aggregate, they may not be so easily assignable to a specific asset or capital project without the incurrence of significant additional expenditures that would have very limited benefit to either the shareholder or the rate payer.

Many regulated entities concentrate their corporate services within holding companies for efficiency in servicing the needs of regulated and unregulated subsidiaries. Hydro One Networks owns and operates two separately regulated transmission and distribution businesses. As such, it is able to provide many of their services on a shared basis rather than replicating them within each business. This results in lower costs and a more efficient delivery of electrical service to end customers. This model also results in a need for comparatively more cost allocation than seen in entities that do not share services. Under Hydro One's model, the costs of shared services are allocated to the serviced affiliates using the Black and Veatch reviewed methodology. Within each regulated business or subsidiary, allocated shared service costs are then classified as either current expense (i.e. OM&A) or capital. As previously stated, both cost allocation and cost classification are based on the same high level criteria – causality or benefit.

For companies that do not share common corporate support expenditures, such amounts are directly charged to capital, or more likely included in capital through the application of standard labour and non-labour rates. The organizational location of departments offering supporting services may influence whether the amount is charged to capital as an indirect cost (e.g. embedded in standard rates) or as an overhead through application of an overhead rate. Thus, a lower overhead capitalization rate compared to another utility may not necessarily be indicative of lower absolute capitalization of indirect support costs. Nor does a lower overhead rate indicate greater productivity or efficiency.

The absence of publicly available information on the organization structure, types and amounts of supporting functions' costs, standard cost structures and overhead allocation methodologies and rates make it very difficult to compare data between entities without conducting very extensive benchmarking studies, likely with the full cooperation of the other entity. However, while a precise peer-to-peer comparison on rates may not be achievable because of general lack of detailed comparative data, Hydro One Transmission's comparison work does indicate the use of a generally consistent practice of using cost causation principles to capitalize corporate support costs and other genera and administrative overheads.

Both legacy Canadian GAAP and US GAAP allow for the capitalization of directly attributable overheads costs under the general accounting principle of matching. This practice is supported by FERC guidance that incorporates the concept of intergenerational equity. Neither GAAP nor FERC provide explicit guidance on specific expenditures that may be capitalized or on cost allocation methods. The GAAP concept of matching and the regulatory principle of intergenerational equity both require the application of causality and benefit assessment to determine which expenditures should be capitalized. As documented in Black and Veatch's independent report, these are the same criteria used to allocate Hydro One's shared service costs to target subsidiaries and regulated businesses. These same criteria are used to determine the proportion of allocated expenditure that should be capitalized.

In its EB-2008-0408 Report, "Transition to International Financial Reporting Standards," under Issue 3.3, the Board commented on intervenor concerns that the adoption of IFRS, entailing a significant reduction in the types of expenditures that qualify for capitalization, could result in significant intergenerational inequities. Interestingly, in its report, the Board expressed an opinion that "the capitalization principles as they now appear in IFRS recognize the nature of indirect costs and whether they are truly attributable to capital projects. The ability of the Board to set just and reasonable rates is enhanced by clarity in capitalization principles that emphasize cost causality." Hydro One agrees with the view expressed in the last sentence and recognizes that the strict application of IFRS rules could result in significant shifts from rate base to revenue requirement for certain utilities. In section 3.3 of its report, the Board also noted that "It will be important for the Board to have a clear understanding of utility capitalization practices, and the effects, if any, of a shift to IFRS capitalization principles. The Board therefore supports the requirement for utilities to file their capitalization policies in their first cost of service filing after the transition to IFRS, and will also require that the revenue requirement impacts of any change in capitalization be specifically and separately quantified." The $200 million quantification of the impact of an IFRS capitalization policy was made clear in EB-2010-0002.

Hydro One Transmission undertakes large capital investments for network upgrades, local supply development projects and replacement and refurbishment of aging infrastructure. These capital projects are constructed and managed internally by the Transmission Business. Significant shared corporate support costs are directly caused by this capital construction program. If the internal construction program did not exist, many of these expenditures would not be required or could be reduced.

In addition, if such projects were outsourced to a turnkey engineering firm, many of these indirect costs and general and administrative overheads would be embedded in the construction costs charged by the turnkey contractor and would be capitalized without question, even under the constraints of IFRS. To comply with the regulatory principle of intergenerational equity, it is logical that the same classification as OM&A or capital should occur irrespective of whether the capital work is self-constructed or turn-keyed.

5. Conduct Industry Research

Key findings: Hydro One's practice, both in terms of the type and proportion of overhead and indirect expenditures capitalized, is consistent with the practices of other North American rate regulated utilities.

Methodology

As requested, Hydro One included a review of the practice of other rate regulated entities in other North American jurisdictions as part of the critical review of its cost capitalization policy. Hydro One notes that the Board asked the Company to gather comparative data but that this exercise was explicitly not intended to constitute a formal benchmarking exercise. This industry research included an examination of the financial statements and regulatory filings of some of the largest utilities in Canada and the US to obtain information on the nature of their overhead and indirect cost capitalization practices and rates. A summary of the research findings can be found in Appendix A.

During the course of its research, Hydro One found that publicly available information on the types of expenditures capitalized as overhead was very difficult to gather from available sources such as financial statements, securities filings and regulatory applications costs and the capitalization percentages. In addition, it was also very difficult to access comparable information on overhead percentages and rates. The Company expects this difficulty results from the fact that detailed disclosure of an entity's indirect cost and overhead accounting practices is not required disclosure under either US or legacy Canadian GAAP. In addition, there is no requirement for entities to disclose detailed information on which overheads or indirect costs are capitalized in their summary of significant accounting policies disclosed within their financial statements. Finally, risk and liability issues applicable to public securities filers have the effect of discouraging voluntary disclosure of information and make approaching another company for information difficult. As there is no offsetting incentive for companies to publicly disclose such information, virtually none do so.

In its review of the practices of other major transmission utilities, Hydro One started its review with major US transmission utilities. In recognition of the difficulty encountered in accessing detailed information on the overhead capitalization practices of these entities, the scope of the comparison was expanded to capture other major Canadian utilities and even large Ontario local distributors. Given the similarities between US and legacy Canadian GAAP, as well as similarities in the cost of service regulatory model in the Canadian and US jurisdictions, this was deemed to be appropriate.

Observation Summary

A detailed summary of Hydro One's findings from reviewing nine Canadian and nine US companies is included as Appendix A. Several other major US companies were also investigated but no useable information was derived from their publicly available financial or regulatory information.

The following table provides a high level summary of the findings with respect to overhead capitalization rate:

Overhead Capitalization Rate (as a percentage of gross operating costs*)			
Hydro One	**Canadian Utilities****	**U.S. Utilities****	**Analysis**
Transmission (2013) – 20%	Industry Median*** - 19%	Industry Median**** - 19%	• The range of overhead capitalization rates varies across the utilities in Canada and US. For Canadian utilities it ranges from 5% to 35.6% with an observed median of 19%. For U.S. utilities, it ranges from 7.33% to >50% with an observed median of 19%. • The rates are based on legacy Canadian GAAP for Canadian utilities and US GAAP for US utilities. However, both accounting frameworks are substantively the same in this area.

* *Gross operating costs include capitalized overheads added back.*
** *Refer Appendix A for a list of the Canadian and U.S. utilities researched and summary of findings.*
*** *Median represents middle value of the range of overhead capitalization rates for those utilities selected for research and where rate information was available.*
**** *The US median is based on a concentration of three results in the 19% range, with one individual outlier at ~7% and another >50%.*

The comparative analysis performed for this report resulted in the identification of a range of acceptable accounting practices and capitalization rates prevalent in the industry. For example, an organization with a shared services structure where broad corporate management and administrative functions are centralized could be characterized by larger overhead allocations from the central indirect costs pool to business units. A more decentralized operation would have the majority of management and administrative costs directly attributed to the target activities, capital and operations.

The key observations made for the Canadian and US utilities researched were as follows:

- The majority of utilities capitalized general and administrative expenditures by including these costs in their overhead capitalization methodology. Some of the more common types of support expenditures within this category include finance, corporate communications, human resources, law, treasury, strategy, information technology, regulatory affairs and other corporate support costs.

- The most common capitalization methods in use appear to be a mix of direct allocation, cost drivers and time studies. In addition, there is evidence that external capitalization studies, such as the one Black and Veatch does for Hydro One, are performed from time to time by some entities.

- The majority of utilities capitalized corporate services expenditures under their capitalization approach. There are variations in the proportions that service expenditures are charged and capitalized as indirect costs (for example those included in the standard labour rates) or charged as overhead costs through the application of an overhead rate. Hydro One's comparison shows that most of corporate services costs appear to be charged to capital through overhead rates rather than being included in standard labour rates.

- All of the US utilities referenced compliance with FERC guidelines as the basis for their overhead capitalization practice.

6. Conclusion

Key findings: Hydro One's cost capitalization policy with respect to overhead and indirects expenditures is consistent with GAAP, regulatory guidance and regulatory practice. Hydro One's cost capitalization policy is appropriate.

As directed by the OEB, Hydro One critically reviewed its cost capitalization policy with a particular focus on overhead and indirect costs. Hydro One found that its treatment is not inconsistent with other major US and Canadian industry participants. In addition, Hydro One concluded that its methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with legacy Canadian and existing US GAAP. In addition, and more importantly, Hydro One's methodology is consistent with regulatory principles including the key goals of achieving intergenerational equity and avoiding cross subsidization.

Summary of Findings - Canadian Utilities

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates CGAAP *(as a % of gross operating costs)*	Reference
1.	BC Hydro, British Columbia Utilities Commission.	• Capitalized Overhead of $278M for 2011 is approximately 21% of operating costs. • Capitalized Overhead would be reduced to a $100 million under IFRS (9%). BC Hydro proposing to use a regulatory account to phase in the resulting increase over a 10 year period. • More recently they have proposed to use US GAAP.	• **Corporate Costs** – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement)	• 21% *(percentage is derived from capitalized overhead value and operating costs values extracted from reference documents)*	• Amended F2012 to F2014 Revenue Requirements Application.
2.	Toronto Hydro Electric System (THES), Ontario Energy Board(OEB).	• Overheads allocated based on cost drivers/time study and include cost of corporate functions and services and employee future benefits. • Proposing to use US GAAP from 2012 with no material impact on overhead rates.	• **Corporate Costs** – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board) • Fleet indirects and procurement indirects are recovered through standard labour rates.	• *~ 22%* *(percentage is derived)*	• Exhibit C1, Tab 3, schedule 4(EB-2011-0144).

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
3.	Hydro Ottawa, Ontario Energy Board (OEB).	• Overheads allocated based on cost drivers/time study and include cost of corporate functions and services and employee future benefits. • Overhead rates will reduce to 10.3% on adopting IFRS based capitalization approach. Allocation to capital reduced by $10.5 million.	• Corporate Costs – Chief Regulatory officer, General Council, Hold Co Corporate Costs, COOs office, Finance, Supply Chain, Human Resource, IT, Supervision, Operations Engineering.	• 15.4% *(Percentage extracted from referenced document)*	• 2012 EDR Application.
4.	Fortis BC, British Columbia Utilities Commission.	• Fortis BC (Electricity) requested approval of US GAAP for rate setting. As part of its 2012-2013 application Fortis BC updated its methodology for calculating Capitalized Overhead resulting in a 23.9% capitalization rate. Fortis BC proposes to continue using the 20% for 2012-2013. • Fortis BC (Electricity) derives their corporate overhead rate through a 3 step process. First a driver is identified for each corporate department. Next the department costs are allocated to the operating business units (Generation, Network Services, Customer Service) using the drivers. Finally the relative proportion of capital related work in the operating business units are determined based on relative labour hours charge to O&M versus capital in 2010. : Generation 75%, Networks Service Customer Service 13 %.	• Fortis BC (electricity) Corporate Costs – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Health and Safety, Environmental. • No detailed component information available for Fortis BC (Gas)	• Electricity-20% (increased to 23.9% beyond 2012-2013) • Gas - 14% *(Percentage extracted from referenced document)*	• 2012-2013 Revenue Requirement Application.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
5.	Enmax Power Corporation, Alberta Utilities Commission.	• The Alberta Utilities Corporation (AUC) approved a 7 year Formula Based Ratemaking for the period 2007 to 2014 for Transmission and Distribution. Included was approval for a 19% overhead capitalization rate for the term of the plan with a 3% escalation per year. • A mix of time study, cost-drivers and direct attribution is used for allocation of overhead costs.	• **Corporate Costs** – (Finance, Information Technology, Human Resources, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement)	• 19% *(Percentage extracted from referenced document)*	• 2007-2016 Formula Based Ratemaking Decision issued in March 25, 2009.
6.	Union Gas, Ontario Energy Board.	• Union Gas forecasts capital overhead as 14.9% of total utility operating and maintenance costs in 2013. This is consistent with the 2007 Board-approved levels of 15%. • A mix of direct attribution, time studies and cost drivers is used for allocation of overhead costs.	• **Corporate Costs** – (Executive, Asset Operations, Regulatory and Business Services, Finance, Human Resources, Corporate Services, Legal, Strategic Development, Information Technology.	• 14.9% *(Percentage extracted from referenced document)*	• EB-2011-0210, Exhibit D1, Tab 2.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
7.	Enbridge Gas Distribution.	• Administrative and general overheads are capitalized based on cost drivers/time study and approved by Enbridge's Board.	• Detailed information on cost components not available.	• 6.8% *(Percentage extracted from referenced document)*	• EB-2011-0008, Exhibit B, Tab 4, Schedule 2.
8.	Newfoundland Power, Board of Commissioners of Public Utilities.	• Certain general expenses related, either directly or indirectly, to the Company's capital program are capitalized based on approval from the regulator. • For 2012 General Expenses Capitalized is $2.8 million Compared to Operating Costs of $52.7 million.	• Detailed information on cost components not available.	• 5% *(percentage is derived from capitalized overhead value and operating costs values extracted from reference documents)*	• 2012 Capital Budget Application and 2010 General Rate Application.
9.	Powerstream, Ontario Energy Board (OEB).	• Overheads allocated based on payroll burden study and include management, engineering, stores and vehicle burdens loaded to standard labour rates.	• Detailed information on cost components not available.	• Management Burden - 6% • Engineering Burden - 60% *(Percentage extracted from referenced document)*	• EB-2008-0244, Exhibit B1, Tab 3, Schedule 1.

Summary of Findings - U.S. Utilities

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
1.	Southern California Edison, California Public Utilities Commission (CPUC).	• Administrative and General ("A&G") overhead costs are based on study approved by the regulator. • Overheads allocated based on cost drivers/time study and include cost of corporate functions and services like human resource, IT, corporate finance and risk assessment and strategy. Pensions and benefits are capitalized at 37.7%.	• Corporate Cost – Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, Treasurer. • Strategy – General Functions and Information Technology. • Operations Support – Training, Environmental, Health and Safety.	• 19.4% *(Percentage extracted from referenced document)*	• 2012 General Rate Case Exhibit No. SCE-07, Vol.01 Chapter I, X and XI and work papers • 2009- General Rate Case proceedings with CPUC.
2.	San Diego Gas & Electric Company (SDG&E), California Public Utilities Commission (CPUC).	• A percentage of certain A&G direct costs, including A&G Salaries, shared service costs, outside services employed, are reassigned to construction each year. The transfer rate to construction projects is determined by an A&G effort study last conducted in 2009 and approved by CPUC. Other costs capitalized include fleet, purchasing, warehousing and pension benefits.	• A&G costs represent corporate services and include A&G salaries, shared services, office supplies and expenses and outside services employed.	• Labour overheads to capital-33.9%. • A&G costs to capital - 18.1% *(Percentage extracted from referenced document)*	• 2012 Gen. Rate Case Exhibit SDG&E-43 Segmentation & Re-Assignment Rates and work papers

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
3.	Pacific Gas & Electric Company (PG&E), California Public Utilities Commission (CPUC).	• Overhead allocation is based on detailed review by Corporate Service departments to calculate the appropriate administrative and general (A&G) capital allocation. Pensions and benefits are also capitalized. • No information available on non-labour related overhead allocation rates.	• Detailed component information on corporate services was not available. • A significant portion comprised of A&G labour costs.	• 7.33% of A&G labour costs allocated to capital. *(Percentage extracted from referenced document)*	• Decision on Test Year 2011 A.09-12-020, I.10-07-027 • Ex PGE-006: 2011 GRC Prepared Testimony: Exhibit 6 – Admin & General Expenses.
4.	Kansas City Power and Light Company, Missouri Public Service Commission	• Indirect A&G costs include corporate services costs, executive salaries and indirect labour. • The Uniform System of Accounts addresses the indirect allocation of A&G payroll to construction activity.	• A&G costs include corporate services - (Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, and Treasurer).	• The labour allocation to construction at 19.33% was based on a study filed with the regulator in 2006. *(Percentage extracted from referenced document)*	• Missouri PSC, Utility Services Division, Direct Testimony of Kimberly K. Bolin, Staff, Case No. ER-2006-0314.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
5.	Commonwealth Edison Illinois Public Utilities Commission	• An Administrative and General Overheads ("A&G") study was done by Commonwealth Edison, (ComED) to justify its overhead allocation between capital and OM&A to the regulator for the year 2001 to 2004. • The study was done by an external consultant Alliance Consulting Group ("ACG"). • The study showed that since about 1999 ComEd began incurring increased levels of capital expenditures compared to prior years primarily reflecting ComEd's increased investment programs to improve the reliability of its distribution system. In addition, during the period, ComEd implemented accounting changes and made operational decisions that reflect a systematic plan to shift costs from O&M expense to capital.	• Indirect cost components include – Labour, Employee Benefits, Supervision, General and Administrative, Contracting, Affiliate Services, Indirect Materials, Vehicle Fleet and Corporate and Other Support.	• A&G distributed to capital- ▪ 2001-57.2% ▪ 2002-60% ▪ 2003-70.9% ▪ 2004-71.4% • Capitalization rate information is not available. *(Percentage extracted from referenced document)*	• A&G Effort Study, Chapter VI Analytical and Other Review, Page A-305.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
6.	Bonneville Power Administration (BPA).	• Capitalized costs include direct labour and materials, payments to contractors, indirect charges for engineering supervision and similar overhead items.	• Detailed information not available. • Includes indirect costs for engineering and supervision.	• Capitalization rate information is not available.	• Bonneville Power, 2011 Annual Report, Audited FS
7.	UNS Electric (Arizona), Arizona Corporation Commission	• It appears that they capitalize A&G expenses according to Decision of Arizona Corporation Commission on rates for 2008. Expenses are related to shared service group and administrative costs associated with installation of equipment to serve customers, even though such costs can not be traced directly to individualized capital projects	• Capitalized A&G includes shared services cost which represent general and administrative overheads and corporate services.	• Capitalization rate information is not available	• Decision 70360, Docket No. E-04204A-06-0783, Appln. of UNS Electric Inc. before Arizona Corporat-ion Comm.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
8.	Seattle City Light (Seattle City Council)	• A&G capitalized is assumed in financial forecast but no rates given.	• Detailed information not available.	• Capitalization rate information is not available	• Revenue Require-ments Presentation, RAC Meeting 2, Sept 22, 2009.
9.	Illinois Public Utilities Commission	The Uniform System of Accounts for Electric Utilities Operating in Illinois talks about overhead allocation: • Overhead construction costs to be charged on the basis of the amounts of such overheads reasonably applicable. • Determination of payroll charges included in const. overheads to be based on time cards. Where impractical, special studies shall be made periodically.		• Capitalization rate information is not available but the Illinois utilities USofA support capitalization of indirect costs and general and administrative overheads.	• Working Copy of the USoA for Electric Utilities Operating in Illinois, Illinois Commerce Comm. Accounting Department August 1, 2007.

Ontario Energy Board (Board Staff) INTERROGATORY #076

Reference:

Exhibit B1/Tab3/ Sch 10 – Attachment 1 – Review of Overhead Capitalization Rates (Transmission) – 2017-2018

Interrogatory:

In Section D of the Overview, Hydro One indicates that a time study, in this case the four-week period ending June 12, 2015, was used as the basis to determine the portion of costs to be capitalized.

a) Could the period in which the time study is conducted potentially impact its results? For example, if the study was conducted during a period of abnormally high or low capital spending activity, could the results be skewed?

b) If so, what is done to ensure that the period selected for the time study is indicative of normal operations so as to ensure that any estimates or assumptions derived from the results are accurate and reasonable?

Response:

a) A portion of the Common Corporate Costs is allocated through the time study. Regarding the time period when the study was performed, please refer to EB-2016-0160 Exhibit C1-6-1, Attachment 1, page 15, paragraph 5 of 6.

b) N/A.

Ontario Energy Board (Board Staff) INTERROGATORY #077

Reference:

Exhibit B1/Tab3/ Sch 10 – Attachment 1 – Appendix A – Transmission Overhead Capitalization Rates – BP 2017-2018 – Review

Interrogatory:

The Overhead Capitalization Rates are developed based on Business Plan numbers and estimates.

Please provide a retrospective analysis that compares the amounts capitalized in previous rate applications for test years 2011 to 2015 to the actual amounts capitalized during each of the given years.

Response:

Please see below for filed amounts capitalized and actual amounts capitalized:

	2012	2013	2014	2015
Actual	$106.9M	$109.3M	$124.3M	$116.9M
Filed	$117.7M	$113.8M	$114.3M	$122.2M

Ontario Energy Board (Board Staff) INTERROGATORY #078

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S06 – Air Blast Circuit Breaker Replacements – Lennox TS

"Need: To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Lennox TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability."

Interrogatory:

a) Is the need to replace any of these breakers contingent upon ongoing operation of OPG's Lennox Generating Station?

b) If yes, please identify how many breakers are contingent upon ongoing Lennox GS operation and provide confirmation that the Lennox GS will either continue to operate for the expected service life of the new breakers or will backstop cost responsibility for the unused lifespan.

Response:

a) Yes, two of the sixteen breakers at Lennox TS are to support the ongoing operation of the plant. The remaining fourteen breakers at Lennox TS are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence. These breakers are required for continued transmission system operation.

b) Of the sixteen breakers being replaced, only two air-blast circuit breakers (ABCB) are contingent upon operation of OPG's Lennox Generating Station. Hydro One has involved OPG during the planning of this project and is not aware of any plans for discontinuing operation of the Lennox Generating Station. In fact, OPG owns and operates two 500kV and two 230kV ABCBs located within Hydro One's Lennox TS switchyards and OPG is coordinating the replacement of its breakers with the Hydro One breaker replacements.

Ontario Energy Board (Board Staff) INTERROGATORY #079

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S08 – Station Reinvestment – Beach TS

Project No.	Investment Summary	Total Cost
S08	*The project entails:* • *Extensive refurbishment and reconfiguration of Beach TS which will result in the replacement of two transformers, seven 230 kV oil circuit breakers, one 115 kV oil circuit breaker, associated disconnect switches, and protection, control and telecom equipment;* • *Upgrading of oil spill containment facilities to comply with the Ministry of Environment and Climate Change requirements.*	*$76.5 M*

Interrogatory:

Please provide a detailed breakdown of the $76.5M investment, highlighting any exceptional requirements and justifications for those requirements that contribute to the capital costs.

Response:

A detailed breakdown of the Beach TS investment is noted below.

	Category	Cost ($M)
Capital & Minor Fixed Assets	Materials	24.3
	Construction	24.0
	Project Management / Engineering / Commissioning	11.0
	Contingency	2.0
	Interest & Overhead	16.0
Operations, Maintenance & Administration and Removals		(0.8)
Net Investment Cost		**76.5**

Detailed engineering revealed that the station layout makes in-situ asset replacement unfeasible due to insufficient clearance and inadequate support structures. Due to the criticality of the station in the Hamilton/Niagara region, the only viable approach was to rebuild the existing 230kV switchyard in a greenfield location to facilitate the replacement, relocation, and reconnection of transformers T3 and T4 to the 230 kV system required in order to maintain system reliability during the duration of the project. Details of the Beach TS investment are detailed in Exhibit B1, Schedule 3, Tab 11, Reference # S08.

Ontario Energy Board (Board Staff) INTERROGATORY #080

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S11 – Station Reinvestment – Elgin TS

Project No.	**Investment Summary**	**Total Cost**
S11	*The project entails:* • *Reconfiguration of Elgin TS by replacing and upgrading existing facilities with new equipment built to current standards including: the 115/13.8kV transformers, the low voltage switching facilities (including thirty-eight low voltage breakers) with a new medium voltage gas-insulated switchgear building installation, protection and control facilities, and other associated ancillary equipment; as well as the oil spill containment facilities will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements; and* • *Replacement of four transformers with two standard units; the other two transformers will no longer be required as a result of the reconfiguration to a standardized design.*	*$58.2 M*

Interrogatory:

Please provide a detailed breakdown of the $58.2 million investment, highlighting any exceptional requirements and justifications for those requirements that contribute to the capital costs.

Response:

A detailed breakdown of the Elgin TS investment is set out below.

	Category	**Cost ($M)**
Capital & Minor Fixed Assets	Materials	27.5
	Construction	6.7
	Project Management / Engineering / Commissioning	7.4
	Contingency	3.9
	Interest, Overhead & Estimating	12.7
Net Investment Cost		**58.2**

Due to significant space constraint within the existing Elgin TS station property, the most viable option for station refurbishment and reconfiguration was through the construction of a new building to house the medium voltage gas insulated switching facilities. The construction of a new building is an exceptional requirement that has contributed to the overall capital cost and is required to facilitate the construction of new facilities while maintaining existing facilities in service during the duration of the project, as Elgin TS is a critical supply point for downtown Hamilton. Details of the Elgin TS investment are detailed in Exhibit B1, Schedule 3, Tab 11, Reference # S11.

Ontario Energy Board (Board Staff) INTERROGATORY #081

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S11 – Station Reinvestment – Elgin TS

*"**Need:** To address multiple assets at Elgin TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs, which directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area."*

Interrogatory:

The statement: "are in need of replacement due to poor (or degraded) condition, obsolescence and high maintenance costs" or similar wording has been used in many of the integrated substation project need descriptions. Has Hydro One conducted business case evaluations or cost/benefit analyses for all of the integrated substation projects included in this filing?

a) If yes, please provide the business case evaluation or cost/benefit analysis conducted for each project

b) If no, please explain if the copied text (or similar wording) should be considered an appropriate level of business justification for such a diverse range of large investments.

Response:

a) No, a portion of the integrated substation projects are still awaiting business case evaluation before the projects are released for execution.

b) Hydro One's internal approval process requires business case evaluation be completed prior to the release of the integrated substation project for execution. All of the integrated substation projects included in the filing have gone through the Asset Risk Assessment process Exhibit B1, Tab 2, Schedule 5 to validate and justify asset need and the Investment Summary Documents submitted with this application provide a summary of that need.

Ontario Energy Board (Board Staff) INTERROGATORY #082

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S01 – Air Blast Circuit Breaker Replacement – Beck #1 SS, S02 – Air Blast Circuit Breaker Replacement – Beck #2 TS, S03 – Air Blast Circuit Breaker Replacement – Bruce A TS, and S07 – Air Blast Circuit Breaker Replacement – Richview TS

Project No.	Original Station ISD	Station Age (as of 2016)	Investment Summary	ABCB Age
S01	*1947*	*69 years*	*Replacement of two ABCBs*	*44 years*
S02	*1955*	*61 years*	*Replacement of twenty ABCBs*	*48 years*
S03	*1976*	*40 years*	*Replacement of sixteen ABCBs*	*44 years*
S07	*1957*	*59 years*	*Replacement of twenty-four ABCBs*	*50 years*

Interrogatory:

a) Some of the above listed ABCBs were either first installed or replaced soon after the original station ISD;

- S01: ABCBs were first installed or replaced starting in 1972, 25 years after the facility was originally built in 1947.
- S02: ABCBs were first installed or replaced starting in 1968, 13 years after the facility was originally built in 1955.
- S07: ABCBs were first installed or replaced starting in 1966, 9 years after the facility was originally built in 1957.

Please explain why the above listed additions (or replacements) occurred so soon after initial station commissioning.

b) The sixteen ABCBs being replaced under S03 are 44 years old, but the station is only 40 years old. Please explain this discrepancy.

Response:

a) Each station evolves over time and is developed consistent with system and customer requirements at the time. The dates being cited (i.e., 1972 for Beck #1 SS, 1968 for Beck #2 TS and 1966 for Richview TS) of when the ABCBs were first installed or replaced were new ABCB installations, according to Hydro One records.

b) The age of the air blast circuit breakers refers to the year that they were built (see OEB Interrogatory Response #17) in 1972, whereas the age of the station is the year that the station was commissioned in 1976.

Ontario Energy Board (Board Staff) INTERROGATORY #083

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S08 – Station Reinvestment – Beach TS; S11 – Station Reinvestment – Elgin TS; S13 – Station Reinvestment – Gage TS S14 – Station Reinvestment – Kenilworth TS

Project No.	Station	Original ISD	Approximate Age	Need
S08	*Beach TS*	*Late 1940's*	*65+ Years*	*Replacement due to poor condition, obsolescence and high maintenance costs*
S11	*Elgin TS*	*Late 1960's*	*48 Years*	*Replacement due to poor condition, obsolescence and high maintenance costs*
S13	*Gage TS*	*1940, with additional capacity in 1960's*	*75+ Years (from original ISD)*	*Replacement due to degraded condition and asset demographics*
S14	*Kenilworth TS*	*Early 1950's*	*65 Years*	*Replacement due to degraded condition and asset demographics*

Interrogatory:

a) Please explain why 4 critical transformer stations in the City of Hamilton (Beach TS, Elgin TS, Gage TS and Kenilworth TS) were allowed to fall into the described state of disrepair and obsolescence simultaneously.

b) Please explain how the 4 stations listed above have all reached end of life simultaneously despite having a wide range of station vintages and initial in-service dates.

Response:

a) Uncertainty in the Hamilton Steel industry over the last 10 years delayed Hydro One's investment in this area to manage investment risk associated with the unclear load supply requirements in this area. Hydro One's plan addresses the end of life asset needs at these stations while providing flexibility for future customer requirements. Exhibit B1, Tab 2, Schedule 4, Section 6, describes additional factors that have contributed to the delay in investment.

b) Investment at Gage, Kenilworth and Beach has been delayed as described in part (a) above. Investment at Elgin is aligned with the needs of the assets as determined through the Asset Risk Assessment process, detailed in Exhibit B1, Tab 2, Schedule 5.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #084

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S57 – CIP V6 Transient Cyber Assets & Removable Media

Project No.	Investment Summary	Total Cost
S57	*The new version requirement of NERC's Critical Infrastructure Protection forTransient Cyber Assets and Removable Media has a compliance date of April 1, 2017. This investment is for the deployment of a compliant solution for Hydro One.*	*$12 M*

Interrogatory:

a) Please explain how Hydro One intends to ensure that the project will be implemented price-competitively.

b) Please provide the cost benefit analysis explaining why the proposed investment is the cost-effective solution to achieve compliance with the new NERC requirements.

c) Please explain the interaction between this expenditure and the $68.6 million project O01 (Back Up Centre).

Response:

a) Hydro One has developed several designs for consideration to address the emerging NERC CIP V6 Transients & Removable Media requirements. The solutions being considered are in line with other utilities and are considered standard implementations accepted by the industry. In selecting the deployment solution, the suite of options will be evaluated against a set of criteria such as technical requirements as well as cost. Hydro One will follow the established investment approval and procurement process to source the necessary equipment to deploy a compliant solution.

b) Hydro One has developed and evaluated four (4) options to meet the new NERC V6 Transients & Removable Media requirements. The options were evaluated against a set of criteria for satisfying compliance requirements, costs, end user productivity, ease of deployment, sustainment/management, and longevity (anticipating future requirements and needs). Options proposed are: i) hardening of corporate issued laptops; ii) Bootable USB devices; iii) deployment of stationary laptops for critical sites; and iv) an expansion of either option i/ii to include wireless infrastructure at critical sites. Preliminary cost benefit analysis suggests use of Bootable USB device as the optimum solution.

c) The investment for NERC CIP V6 Transients and Removable Media is targeted to address our Remote substations, hence there is no interaction with the planned construction of the Back up Control Centre.

Ontario Energy Board (Board Staff) INTERROGATORY #085

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S61 – Transmission Site and Facilities Infrastructure

Project No.	Investment Summary	Total Cost
S61	*This program includes HVAC system replacements and general building renovations, including building roof and water supply upgrades.*	*$13.4 M*

Interrogatory:

Please provide historical comparison levels of spending associated with the Transmission Site and Facilities Infrastructure program.

Response:

Historic spending in the Transmission Site and Infrastructure program:

	Historical Actual	**Historical Actual**	**Historical Actual**	**Historical Actual**	**Bridge Budget**
Year	**2012**	**2013**	**2014**	**2015**	**2016**
Historical spending ($ millions)	23.4	22.9	30	20.3	9.4

The recent decrease in program spending, specifically in the bridge and test years, is due to the redirection of funding from the historical Asset-Centric categories of Stations Sustaining Capital to Integrated Station-Centric Investments.

Ontario Energy Board (Board Staff) INTERROGATORY #086

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S67 – D2L (Upper Notch x Martin River) Line Refurbishment, S71 – K1/K2 Line Refurbishment, and S74 – D2H/D3H Line Refurbishment

Project No.	Line Voltage	Equipment to be Replaced	Length of Rebuild	Total Cost
S67	*115 kV*	*Existing ACSR with new similar size conductor; and shieldwire, insulators and all associated hardware. All structures will be refurbished as required.*	*58 km*	*$43.2 M*
S71	*115 kV*	*Existing copper conductor with equivalent ACSR conductor; and shieldwire, insulators and all associated hardware.*	*59 km*	*$15.7 M*
S74	*115 kV*	*Existing ACSR with new similar size conductor; and shieldwire, insulators and all associated hardware. All structures will be refurbished as required.*	*59 km*	*$25.9 M*

Interrogatory:

The three Sustaining Capital Lines projects S67, S71 and S74 listed in the above table have the same line voltage, and have similar rebuild lengths and equipment to be replaced. Please explain in detail the cost discrepancies between these three projects.

Response:

The associated cost for line refurbishment works is heavily dependent on structure type, number of circuits on the line, access to the site and also the condition of structures.

- Project number S67 is for a double circuit steel lattice tower line
- Project number S71 is for single circuit wood pole line
- Project number S74 is for double circuit steel lattice tower line

It should be noted that Project S67 has especially poor structure condition, multiple line taps, and extremely poor foundations with difficult site access. For these reasons it is more expensive than S74.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #087

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S76 – Steel Structure Coating

Project No.	Investment Summary	Total Cost
S76	*The proposed plan will be to reinstate the protective coating on 1,250 and 1,600 steel structures in the 2017 and 2018 test years respectively.*	*$96.9 M*

Interrogatory:

Please quantify the projected future capital and operational cost savings stemming from this program, and show how Hydro One intends to track and validate the expected savings.

Response:

Based on the response in Board Staff 55 section (b), the projected life cycle capital cost savings for 2017 and 2018 is $180 M. This cost saving has been calculated based on the weighted average cost saving of $63.5 K per structure and the number of structures targeted for tower coating in 2017 and 2018.

[(1250 structures in 2017) + (1600 structures in 2018)] x $63.5 K per structure = $180 M total cost savings over two years.

The expected operational cost savings are negligible.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #088

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S80 – Transmission Lines Emergency Restoration

Project No.	*Investment Summary*	*Total Cost*
S80	*The proposed funding for the transmission lines emergency restoration during the test years are based on recent historic levels of spending associated with emergency repairs.*	*$17.5 M*

Interrogatory:

Please provide historic annual levels of spending associated with emergency transmission line repairs for the years 2012 to 2015.

Response:

The historic annual levels of spending associated with transmission lines emergency program have been outlined in Table 16 in Exhibit B1, Tab 3, Schedule 2, which is reproduced below. It should be noted that the total cost of $17.5 M in document S80 is for both test years.

Table 16: Overhead Lines Component Replacement Programs ($ Millions)

Description	**Historic Years**				**Bridge Year**	**Test Years**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Wood Pole Replacements	26.9	32.7	43.6	38.5	38.3	35.3	35.3
Steel Structure Coating	1.6	5.7	5.1	4.6	8.8	42.5	54.4
Steel Structure Foundation Refurbishments	3.3	4.5	3.6	1.6	3.9	7.8	7.8
Shieldwire Replacements	4.4	2.9	8.2	4.3	5.2	7.0	7.1
Insulator Replacements	3.3	6.9	3.8	2.8	26.1	63.9	61.4
Transmission Lines Emergency Restoration	8.0	8.2	8.7	8.8	8.3	8.7	8.8
Other Line Component Replacements	3.4	5.6	5.7	6.0	3.2	5.0	5.2
Total	**50.9**	**66.5**	**78.7**	**66.6**	**93.8**	**170.2**	**180.0**

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #089

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: O01 – Integrated System Operations Centre (ISOC)

Project No.	*Need Summary*	*Total Cost*
O01	*It is essential to proceed with this investment to ensure continued compliance with regulatory requirements regarding having an operable Backup control facility with fully functional monitoring and operation control of the Hydro One Transmission system.*	*$68.6 M*

Interrogatory:

a) When was Hydro One's existing Backup Control Centre commissioned?

b) When and how did Hydro One become aware that its existing Backup Control Centre was not compliant with NERC requirements? Please list all deficiencies at the existing site that cannot be mitigated at the existing site.

c) Please explain which regulatory requirements Hydro One would risk not being compliant with in the event that this project did not proceed or were to be delayed.

d) Please provide a business case or cost/benefit analysis that supports Hydro One's proposal to develop a new integrated System Operations Centre combining its Backup Control Centre, Backup Integrated Telecommunications Management Centre, Telecom Security Events Monitoring and Security Operations functions.

e) Please explain how Hydro One intends to ensure that the project will be implemented price-competitively.

f) Did Hydro One evaluate any alternative lower-cost solutions that would enable it to achieve backup control centre compliance? If yes, provide detailed descriptions of the alternative solutions and explain why they were rejected.

Response:

a) The Hydro One facility that houses the Backup Control Centre ("BUCC") was commissioned in 1956. Prior to the commissioning of the Ontario Grid Control Centre (OGCC) in October

2002, this facility was utilized as Hydro One's Transmission Operations Management Centre (TOMC). Once the OGCC was in-serviced, the TOMC was converted to the current Backup Control Centre.

b) Hydro One's BUCC is currently in compliance with applicable regulatory requirements. The BUCC however, remains at high risk for critical failures which can result in future non-compliance in the event further extended outages are experienced and cannot be adequately remediated or remediated in a timely fashion.

A heightened and unacceptable risk of future extended outages, inability to execute necessary upgrades and replacements and increase capacity to required computer systems and tools, could result in a future non-compliance condition and disrupt business continuity. Below are the key events and risks that will remain in the event this investment does not proceed or is delayed:

1. Transformer Asset Failure Risk – as was experienced in March of 2011, a transformer failure (fire) rendered the facility unavailable for an extended period of time.

2. Flooding Risk – A significant flood in July of 2013 rendered the BUCC inoperable for an extended period and significant investment was required to rehabilitate the facility and return it to an operable state. Although remedial investments to mitigate the risk and impact of future flooding events have been made, the risk has not been eliminated.

3. Site, facility, Data Centre and floor space capacity constraints are result from the inability to undertake a physical expansion of the facility's footprint. The BUCC Data Centre is at capacity and therefore Hydro One is unable to provide backup systems for all critical computer systems and equipment.

4. Site location and the emergency preparedness risks threaten business continuity (proximity to Highways, flight paths etc.). Traffic congestion to the site, necessitates the maintenance of an interim BUCC (used to activate, monitor and control until the BUCC can be manned) required to ensure the NERC two hour activation compliance timelines can be achieved.

5. Given the site conditions of the facility, continuous extensive upgrading and retrofitting is required to maintain compliance. Further details are provided in part (d).

c) For a Backup Control Centre to be compliant, the requirements of the following regulatory standards must be met:

i. NERC –EOP-008 “Loss of Control Centre Functionality”
ii. Restoration Participant Attachment as required by the IESO administered ‘Market Rules’ for the Ontario Power System Restoration Plan (OPSRP).
   a. The BUCC is listed as one of the key facilities which comprise Hydro One’s contribution to the Ontario Basic Minimum Power System.
iii. Required as per EOP-005-2 NPCC-D8 (NPCC Directory 8) and IESO Market Rules & Manuals (Market Rules Chapter 5 – Power System Reliability, Market Manual 7: System Operations, Part 7.8: Ontario Power System Restoration Plan.
iv. NERC Critical Infrastructure Protection (CIP) Requirements – ensuring assets are protected logically (electronic security perimeter) and physically (physical security perimeter)
v. Communications: NERC & IESO Market Rules:
   - NERC-COM-001-2
   - Chapter 2, Appendix 2.2, Section 1.1.4- Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities
   - Chapter 2, Appendix 2.2, Section 1.2.3 – Transmitter Submission to the Energy Management System
   - Chapter 5, Section 12.1.1 – Voice Communications Methods
   - Chapter 5, Section 12.1.6 & Section 12.2.12 – Alternatives During Loss of Communications
   - Chapter 5, Section 12.2.3 – Required Voice Communication Facilities
   - Chapter 5, Section 12.2.4 – Voice Communication Reliability
   - Chapter 5, Section 12.2.11 - Voice Communication Monitoring and Testing
   - Chapter 5, Section 12.3.2 - Required Data Communication Facilities

d) The business justifications, risk mitigation and benefits associated with the proposed ISOC are as follows:

Risk Avoidance, due to the current Facilities deficiencies:

i. Flooding in basement where computer rooms, power rooms, telecom rooms, switchgear, SONET communications, etc., are currently located.
ii. Facility roof and building cable entry leakage.
iii. Generator failures – No redundancy in emergency generator power.
iv. Fire panel failures.

v. HVAC failures, capacity limitations and system constraints as the facility is limited to due to age and design of infrastructure.

vi. High cost for retrofit / maintenance activities.

vii. Competing demands for physical space from multiple tenants (NOD, ITMC, SEM etc.)

viii. Electric power system is undersized and does not meet current or future requirements (Station Service).

ix. Structure is landlocked, and no expansion potential exists as the facility is surrounded by Richview TS.

x. The BUITMC requires extensive setup during activation and cannot accommodate back office support, growth, and regulatory security requirements for access control for critical computing equipment. The current HVAC is not adequate for net new occupancy or equipment and lacks the necessary facilities should a prolonged activation be required. ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and is providing first level support in the event of any communications failure. ITMC requires a new Backup Control Centre to alleviate the heightened risk at the current location.

xi. The current site location requires maintaining an interim backup facility to perform limited functions in the event the OGCC is rendered inoperable and staff have to transition to the Richview BUCC due to activation timelines. The ISOC will eliminate this requirement.

xii. The Security Event Monitoring (SEM) is accountable to provide cyber surveillance monitoring services and requires Data Centre capacity, (not a physical tenant) to support primary operations.

xiii. Security Operations Centre and Emergency Operating Centre required to provide a primary site for operations monitoring and coordinated response for security threats to ensure business continuity.

Emergency Preparedness risk considerations

xiv. In a flight path (Pearson International Airport)

xv. Between two major highways (Hwy 427 & Hwy 401)

xvi. Gas pipe lines located underneath property

xvii. Adjacent to transformer station (electrical, fire and asset failure hazard).

xviii. Congested area in the event of wide spread emergencies i.e. Civil unrest, blackout, natural disaster, and commute.

xix. Adjacent to public storage facilities

By building one centralized site to house all stakeholders, the following benefits would be realized:

1. Economy of scale synergies in negating need for multiple designs, development, sites, facilities (buildings), critical support infrastructure, future maintenance maximizing capital investment;
2. Enhanced monitoring, control and coordinated response (Operating, Telecom, Security and Emergency Preparedness);
3. Share enhanced building protection design and security (both physical and cyber security);
4. Share redundant backup generator power supply and other emergency supplies;
5. Enhanced site location for improved activation response, dual purpose use for training and other business operations; and
6. Enhanced security posture with centralized operations, improved monitoring and analysis trending for proactive response, and situational awareness for coordinated resolution. An Emergency Operations Centre for Business Continuity and Emergency Preparedness will also be provisioned as part of the Security Operations Centre.

e) Leveraging the services of an experienced external design firm, lessons learned from Hydro One as well as other Utility groups, Hydro One has concluded a collaborative ISOC Planning Needs Assessment process and has completed a Design Brief which identifies ISOC requirements. Following the generation of the Design Brief, an interactive detailed design process has been implemented and when completed will provide the necessary construction level documentation to effectively construct the ISOC. Pending completion of the Detailed Engineering Design and receipt of required approvals, Hydro one will leverage its internal Supply Chain, an Open Market Construction Tender process in two phases:

<u>Phase One:</u> Request for Pre-Qualification (‘RFPQ”): Hydro One will seek to pre-qualify a select number of vendors in an open market process, who demonstrate “required competencies” (e.g., proven large project construction experience, defined safety/environmental programs, change control process controls, demonstrated ability to deliver large construction projects on time and to budget, etc.) related to the construction of the ISOC and acceptance of HONI required market-based Terms and Conditions.

<u>Phase Two</u>: Request for Proposal (“RFP”) (pending receipt of the necessary regulatory approvals): Hydro One will release to only the pre-qualified vendors a detailed RFP with a complete set of construction documents. Pre-qualified vendors will be required to review the construction documents, offer input with respect to area’s which could result in increased costs if not addressed before construction and provide a “fixed” price proposal to a defined scope of work and schedule, linked to a delivery penalty.

<u>Post Construction award:</u> Hydro One's external designer will monitor on site activities throughout the construction to ensure any issues are addressed early and that required contract quality is delivered. HONI and designates will participate in interactive Bi-weekly onsite construction process meetings to gauge progress to requirements and address concerns which may impact the process.

f) Please see B1-03-11 O01 Pages 2-3 for alternatives considered, and rationale for rejecting the respective alternatives. One variation of Alternative Two discussed in evidence, is as follows:

<u>Acquire an existing facility that would accommodate an NOD BUCC, and BUITMC.</u>
This alternative was assessed during a real-estate market assessment and it was found that, at that time, no facility existed in the marketplace that would meet mandatory requirements. As such this alternative was rejected from further consideration.

Ontario Energy Board (Board Staff) INTERROGATORY #090

Reference:

Exhibit B2/Tab 1/Sch1 – Section 2: Proposed Transmission Scorecard, pg. 2

"The incentives that are embedded in the Company's compensation plans also support continuous improvement and improvements in these critical metrics and are designed to both increase efficiency and deliver value to customers."

Interrogatory:

Hydro One's primary role is the delivery of electricity transmission services to Ontario customers. Does "increase efficiency" in the above statement mean reduced costs per unit delivery?

a) If yes, how will "increased efficiency" be measured in specific quantifiable terms?

b) If not, what does "increase efficiency" mean and how will it be measured?

Response:

Yes.

a) Increased efficiency at Hydro One will be measured in specific quantifiable terms through the use of metrics related to financial and work program results. These metrics will include cost per unit for specific tasks, line of business expenditures and outcome based measures that will be trended over time to track improvements. An example of some these metrics can be found in the proposed scorecard in Exhibit B2, Tab 1, Schedule 1, Attachment 1, and in the proposed Tier 2 and Tier 3 metrics found in Exhibit B2, Tab 1, Schedule 1, Table 2.

b) Please see response to part (a). Hydro One will use specific quantifiable terms to measure increased efficiency.

Witness: Michael Vels

Ontario Energy Board (Board Staff) INTERROGATORY #091

Reference:

Exhibit B2/Tab 1/Sch1 – Section 4: Process to Develop Scorecard Metrics, Table 1 – Proposed Transmission Scorecard, pg. 5-6

Interrogatory:

As one of the paramount concerns of customers is the cost of receiving electricity service, please explain why the proposed scorecard doesn't include a cost per unit, either in $/MWh of energy delivered or $/MW-year of capacity billed to customers or a measure of total costs to be borne by rate payers over the years.

Response:

Normalizing Cost (either OMA or Capital) by energy delivered (MWh) or MW of capacity billed has been considered in the past. Costs based on unit volume do not account for differences in the geography, topography and customer density of a utility's service territory and its overall system size. The measures proposed: (Total OMA + Capital) per GFA (in %); Sustainment Capital per GFA (in %) and OMA per GFA (in %), account for system size.

Ontario Energy Board (Board Staff) INTERROGATORY #092

Reference:
Exhibit B2/Tab 1/Sch1 – Section 5: KPI Selection, pg. 7

"While many of these metrics are tracked today, others have not been previously measured and will be tracked going forward."

Interrogatory:

a) Please describe how the metrics referenced in the above statement are tracked (e.g.: frequency of reporting, etc.).

b) Has Hydro One considered establishing stretch targets for the test years on the KPIs that are proposed?

Response:

a) Hydro One currently tracks the some of the proposed specific scorecard metrics and KPIs on a decentralized basis in its various lines of business. A framework to track all of the proposed metrics and key performance indicators is currently under development.

b) Stretch targets have not yet been established as many of the metrics are new and have many factors that impact the final results. As Hydro One learns from experience in measuring productivity, the company will continue to evaluate and refine these metrics to ensure they are the appropriate metrics before proposing stretch targets. In the interim, Hydro One will track and trend these metrics to confirm they are representative of the company's performance.

Ontario Energy Board (Board Staff) INTERROGATORY #093

Reference:

Exhibit B2/Tab 1/Sch1 – Section 5: KPI Selection, Table 2 – Tier 2 and Tier 3 Metrics, pg. 10

Performance Categories	***% Satisfaction with Outage Planning Procedures***	***Preliminary Tier 2 Metrics***
Cost Control	*Sustainment Capital/Gross Fixed Assets*	*Actual cost versus estimated costs for completed capital projects (%)*

Interrogatory:

a) Please explain in detail how Hydro One evaluates the quality of its project cost estimates when measured against actual project cost performance.

b) Is it considered good industry practice for project actual costs to consistently fall significantly below estimated costs?

i. If yes, please provide references from established estimating industry groups such as the Association of the Advancement of Cost Engineering (“AACE”).

ii. What does an ongoing pattern of actual project costs consistently falling significantly short of estimated costs potentially indicate (e.g.: that contingency allowances are excessive)?

Response:

a) Hydro One evaluates the quality of its project cost estimates by identifying the original approved estimate, adjusting for approved scope or contract changes, and comparing these against actual project costs. The percentage variance is reviewed to determine if this percentage falls within the range of accuracy of the estimate. If this percentage falls within the range of the estimate accuracy, it is deemed to be of an acceptable quality. This evaluation is completed as part of the project closure process for all projects with budgeted costs greater than $5M. Any estimates with significant deviations are reviewed and captured as part of the lessons learned process. Hydro One also has improvement initiatives underway to improve the relationship between the estimate and actual by aligning the work/cost breakdown structures. For more information on improvement initiatives please see Exhibit B1, Tab 4, Schedule 1.

b) No. The objective of a cost estimate is to predict the total cost of the identified scope of work for a project; the accuracy of the estimate is a reflection of the level of project definition and the information and data available at the time the estimate is compiled.

i) See above.

ii) A pattern of actual project costs falling significantly short of estimated costs could be an indicator of several causes including risks and associated contingency allocation not materializing, productivity gains, as well as deviations in commodity prices and labour escalation rates. Hydro One recognizes that its past escalation and contingency rates were too high and potentially contributed to the deviation between budgets and actual costs. Hydro One has set an annual escalation rate of 2.3% for 2017 and 2.5% for 2018 and a maximum contingency rate of 10% of a project's estimate. These thresholds are in line with the industry norms, and are an improvement from prior practices. Hydro One has advanced several activities into the project definition stage including additional engineering to minimize the need for assumptions during the estimating phase.

Ontario Energy Board (Board Staff) INTERROGATORY #094

Reference:
Exhibit B2/Tab 1/Sch1 – Section 6: Commitment to Productivity Improvement, pg. 12

"Furthermore, as part of recent activities commissioned by the Company's new board and management, a number of initiatives have been identified that are expected to drive greater efficiency and productivity in Hydro One's programs, leading to lower projected OM&A costs. The initiatives include:

- *Savings identified through a full evaluation of Hydro One's procurement program and investments in new processes and tools;*
- *Reductions in administrative expenditures through improved processes and optimization of internal staff skills;*
- *Rationalization of Hydro One's IT spending; and*
- *Improved field efficiency through additional work planning improvements, including several opportunities to improve scheduling and labour efficiency."*

Interrogatory:
a) Please provide additional details for each initiative listed above.

b) Which of the above initiatives are set up to address potential labour shortages or changes in the productivity/experience level of Hydro One staff?

c) Please describe the technologies (e.g.: drones or hand held cameras) being used to lower the cost, time requirement, accuracy/consistency of evaluation, and safety risks for dangerous inspection, conduction inspections and other asset condition assessment activities.

Response:
a) For further details regarding:
- Procurement program savings: see the response to Exhibit I, Tab 1, Schedule 98. New tools have also been implemented for spend analysis to provide increased opportunities to bundle procurement events and increase purchasing power. In addition, an enhanced process for cost transparency from Suppliers during the Request for Proposal process is now in place. These enhancements in tools and processes will result in increased procurement savings. See response in Exhibit I, Tab 13, Schedule 9.
- Optimization of internal staff skills: see Exhibit C1, Tab 02, Schedule 6, section 3.1.2 and response in Exhibit I, Tab 1, Schedule 116;

- IT spending initiatives: see Exhibit B1, Tab 3, Schedule 6, section 1.1;
- Work process and planning improvements for scheduling and labour efficiency: see Exhibit C1, Tab 2, Schedule 6, sections 3.1.3 to 3.2.4, and response in Exhibit I, Tab 1, Schedule 116 and Exhibit B1, Tab 4, Schedule 1, sections 5.0, 6.0 and 7.0;

b) Hydro One will continue to seek new areas of opportunity for the development of productivity and efficiency improvements to increase the amount of work accomplished by the equivalent headcount throughout the Hydro One lines of business. Initiatives such as automating reporting functions and creating common repositories for information will assist in this process. Hydro One will also continue to investigate the use of unskilled or seasonal labour for tasks as appropriate in accordance with the provisions of the negotiated collective agreements.

Hydro One has a robust Corporate Staffing strategy to mitigate potential labour shortages and knowledge transfer initiatives to address changes in experience level as outlined in Exhibit C1, Tab 4, Schedule 1.

c) For details regarding the leveraging of technology currently employed in Hydro One work programs refer to Exhibit C1, Tab 2, Schedule 6, section 3.4. Hydro One will continue to investigate the leveraging of technology to increase productivity and cost efficiencies.

Ontario Energy Board (Board Staff) INTERROGATORY #095

Reference:

Exhibit B2/Tab 1/Sch1 – Section 7: Productivity Metric Selection, pg. 13

"In the [Transmission Total Cost Benchmarking Study], the median levels amongst the peer set for these metrics were found to be:
- *Total Capital Expenditures + OM&A/Gross Fixed Asset Value = 13.9%*
- *Total Capital Expenditures/Gross Fixed Assets = 6.6%*
- *Total O&M/Gross Fixed Asset Value = 4.3%"*

Interrogatory:

a) Please confirm that the median expenditure levels presented in the citation above are derived from a different set of peers than the CEA Composite Group against which Hydro One has compared its reliability performance in Exhibit B1/Tab1/Schedule 3 of this filing.

b) Please compare Hydro One's cost metrics against the cost metrics of the CEA peer group members.

Response:

a) Yes, the Transmission Total Cost Benchmarking Study done by Navigant used a different peer set than the CEA Composite Group.

b) The CEA metrics are not available to Navigant, so comparison of the CEA versus the Hydro One cost study is not possible.

Ontario Energy Board (Board Staff) INTERROGATORY #096

Reference:

Exhibit B2/Tab 1/Sch1 – Section 7.2: Total Capital Expenditures, pg. 15

"Navigant Consulting and First Quartile Consulting cited in the study that Direct CapEx was noticeably lower than the median and has been for several years. Given the relative age of the Hydro One's assets, expectation is that CapEx will need to increase in order to maintain reliability."

Interrogatory:

a) Does Hydro One agree that it makes trade-offs between the planned level of Sustaining Capital Investments and operating costs?

b) How does Hydro One ensure that its capital plan appropriately balances increases in Sustaining Capital Investments against reduced operating costs?

c) Has Hydro One calculated the O&M savings it expects to realize as a consequence of the proposed significant increases in Sustaining Capital Expenditures? If yes, please provide detailed results.

Response:

a) Yes.

b) When Hydro One assesses capital investments, long term operating costs are minimized by leveraging technology and materials to reduce life cycle costs.

c) No. Savings are identifiable on an individual asset basis. However, on a portfolio basis the reduction in OM&A is not possible to estimate. Only a small percentage of assets are replaced through sustainment capital, on an annual basis. The savings attributable to these new assets are outweighed by increases in OM&A arising from the remainder of Hydro One's assets which continue to age and deteriorate. As described in the Navigant benchmarking study, (Exhibit B2, Tab 2, Schedule 1, Attachment 1), Hydro One's OM&A expenses are low relative to its comparators, despite the age and condition of the assets.

Witness: Mike Penstone

Ontario Energy Board (Board Staff) INTERROGATORY #097

Reference:

Exhibit B2/Tab 1/Sch1 – Section 8: Unit Cost Metrics, pg. 17

"In new construction, the asset or station configuration is designed to address the unique local load profile requirements of the station, again making it difficult to compare costs across construction sites."

Interrogatory:

a) Has Hydro One attempted to compare costs across construction sites for these "heterogeneous" activities? If yes, please provide examples.

b) Has Hydro One attempted to break down project costs into major sub-components that are comparable from site to site? If yes, please provide examples.

c) Has Hydro One attempted to implement standardized station configurations and equipment sizes for different load supply ranges?

Response:

a) Hydro One's current SAP work/cost breakdown structure is organized by line of business (i.e. Project Management, Construction, Commissioning, Materials, Interest and Overhead). Hydro One has run some rudimentary assessments to compare these categories across projects and has found that further categorization would be beneficial. Hydro One has initiated a benchmarking initiative to determine which values are most appropriate to use as comparators.

   Most new construction projects are outsourced as they lack the outage and staging complexity of refurbishment work. This allows Hydro One to leverage the external market place for a cost effective solution at market prices. As part of the Contract Management initiative, Hydro One will be looking for measures that can be used internally as well as with external construction partners for an added level of granularity.

b) As part of the project closure process for all capital projects with a total project cost greater than five million dollars, Hydro One compares major subcategories as per the following line of businesses categories:

- Engineering
- Project Management
- Construction labour, fleet, and equipment
- Commissioning
- Materials
- Interest and Overhead

This comparison outlines and identifies the variances from the original approved budgets (including approved scope changes) with the final actual project costs to arrive at the variance dollar amount and percentage for each subcategory.

As part of the Project Controls initiative currently underway, Hydro One will improve the alignment of the existing work/cost breakdown structure to facilitate cost comparisons at a lower level of detail (for example, foundations, site preparation, and steel structures, etc.). In addition to facilitating a lower level comparison of estimate to actuals, Hydro One hopes to be able to compare and contrast like for like commodities and monitor project performance between different projects.

c) Hydro One has standardized its selection of major assets such as transformers, breakers and protection and control devices. For example, transformers have been reduced to only 14 standard types, allowing for the standardization in configurations to improve efficiency from multiple perspectives. Exhibit B1, Tab 3, Schedule 2, page 18, provides additional information relating to transformer standardization.

Ontario Energy Board (Board Staff) INTERROGATORY #098

Reference:

Exhibit B2/Tab 1/Sch1 – Section 10.2: Procurement, Table 5 – Historical Performance Productivity Metrics, pg. 22

"The Planning Index measures material ordering according to manufacturer contracted lead time and gauges the efficiency of the ordering process. The Supply Chain Services Value Realization metric relates the value generated by the procurement organization (through discounts and strategic sourcing) as a percentage of the costs incurred to run the procurement organization."

Table 5: Historical Performance Productivity Metrics

	Metric	2011	2012	2013	2014	2015
Administrative Costs	Administrative costs as % of Net OM&A & Capital Expenditures	N/A	11.4%	13.3%	11.9%	10.5%
	Overhead as % of Net Capital Expenditures	13%	14%	15%	15%	12%
Supply Chain	Planning Index (material ordering per lead time)	89%	93%	94%	89%	85%
	Supply Chain Services value realization (Value generated/cost)	0.46	0.70	0.78	0.62	0.93

Interrogatory:

Please provide detailed examples of the calculation of the Planning Index and Supply Chain Services Value Realization metric figures shown in Table 5 above

Response:

Planning Index

The planning index indicates how well the various Lines of Business (LOB) are planning for any material needs. This index compares the time between when the purchase requisition is approved to the requested delivery date against the material lead time.

How the index is calculated:

Items under Contract: If [Direct Ship Delivery Date] – [Contractual Lead Time] >= 0, pass

Items NOT under Contract: If [Direct Ship Delivery Date] – [Material Master Lead Time] >= 0, pass

Stock Items (Warehouse): If [Stock Transfer Delivery Time] **–** [Stock Lead Time of 7 Days]>= 0, pass

All three components are rolled up into a single index value and reported monthly. Total yearly figure is calculated through an aggregate of monthly numbers and the Total Passed Lines are divided by the Total Requisition Lines. For 2015, the calculation is as follows:

147,439 Passed / 172,627 Total Lines = 85.4%.

Individual examples are shown below.

Example 1
Purchase Requisition #: 1
Purchase Order #: 1
Purchase Requisition Approval Date: Dec 1, 2015
Requested Delivery Date: Dec 10th, 2015 (9 days)
Planned Delivery Time from Contract: 3 days
Result: **PASS –** 9 days is greater than the contractual requirement of 3 days

Example 2
Purchase Requisition #: 2
Purchase Order #: 2
Purchase Requisition Approval Date: Dec 11th, 2015
Requested Delivery Date: Dec 19th, 2015 (8 days)
Planned Delivery Time for Stock Transfers: 7 days
Result: **PASS –** 8 days is sufficient time to satisfy the 7 day stock requirement

Value Realization

The Value Realization Metric is a way of measuring how effective Supply Chain is at reducing the cost of materials and contractual services relative to its cost to provide this service. Supply Chain achieves these cost reductions and savings through negotiations, strategic sourcing initiatives as well as early pay and volume discounts. This metric also allows the opportunity for Supply Chain to improve through reducing its total organizational cost such as through labour and/or administrative reductions. The calculation using the Value Realization metric and the costs for 2015 is shown below.

Value Realization	
Negotiations	18.5
Strategic Sourcing	12.8
Early Pay & Volume Discounts	4.6
Total Value Generation	35.9
Cost of Supply Chain Services	38.5
Value Realization (35.9 / 38.5=)	**93%**

Ontario Energy Board (Board Staff) INTERROGATORY #099

Reference:

Exhibit B2/Tab 1/Sch1 – Section 10.3.1: Stations, pg. 23

"Hydro One selected the ratio of unplanned work to planned work as a complement to the stations RCE metric. This metric provides insight into the effectiveness of maintenance work planning and of unplanned outage prevention. An effective preventive maintenance program would lead to less unplanned work, and reduce the ratio of unplanned to planned work."

Interrogatory:

Please provide definitions of unplanned work and planned work.

a) Is unplanned work any activity related to addressing an unplanned outage?

b) Is the measure in dollars or in hours? If other, please specify.

Response:

Planned Work is defined as preventative or corrective maintenance that is carried out according to a fixed plan.

Unplanned Work is defined as maintenance that is performed without planning, on demand, which could be related to a breakdown, repair or corrective work.

a) Examples of unplanned work identified in the metric are Power Equipment Demand Correctives, Field Switching and Right of Way Demand Correctives (e.g. brush clearing). Unplanned work can be non-outage driven as well as outage driven, however the majority of the expenditures would be related to outage driven events. Examples of Planned work are Power Equipment Preventative Maintenance and Planned Corrective work.

b) The measure is in dollars.

Witness: Michael Vels

Ontario Energy Board (Board Staff) INTERROGATORY #100

Reference:

Exhibit B2/Tab 1/Sch1 – Section 9: Reliability and Cost Efficiency Metrics, Table 4 – Historical and Projected RCE Metrics, pg. 20;

Exhibit B2/ Tab 1/Schedule 1–Section 10.3.2: Project Delivery and Construction, pg. 23; Exhibit B1/Tab 2/Schedule 3–Section 5.3[1]: External Comparisons of Reliability, Figure 13–Unavailability of Major Transmission Station Equipment, pg. 26

Table 4: Historical and Projected RCE Metrics

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Stations	Outages/Assets	117.0	105.7	103.9	85.6	98.0	87.7	80.8	74.8	70.0	63.7
	Assets/Maintenance	42.6	47.2	46.0	58.2	56.9	62.3	66.8	76.6	72.1	81.4
	RCE	**2.7**	**2.2**	**2.3**	**1.5**	**1.7**	**1.4**	**1.2**	**1.0**	**1.0**	**0.8**
	RCE (3 year average)			**2.4**	**2.0**	**1.8**	**1.5**	**1.4**	**1.2**	**1.0**	**0.9**
Lines & Forestry	Outages/Assets	132.4	139.5	132.3	115.8	120.2	78.8	88.8	108.4	101.0	94.7
	Assets/Maintenance	86.0	98.4	94.8	109.4	100.3	92.9	101.7	71.2	75.4	79.0
	RCE	**1.5**	**1.4**	**1.4**	**1.1**	**1.2**	**0.8**	**0.9**	**0.8**	**0.8**	**0.8**
	RCE (3 year average)			**1.5**	**1.3**	**1.2**	**1.0**	**1.0**	**0.8**	**0.8**	**0.8**

Table 6: Performance of Productivity Metrics

	Metric	**2011**	**2012**	**2013**	**2014**	**2015**
Work Execution	ISA as % of the OEB approved budget	95%	75%	90%	106%	85%
	% of budgeted work completed on or ahead of schedule	N/A	N/A	50%	85%	67%
	Engineering costs/ ECS Capital $	N/A	9.15%	9.14%	7.96%	8.23%
	Ratio of Stations unplanned work to planned work	36%	35%	38%	42%	41%

[1] Should read B1/Tab 1/Schedule 3–Section 5.3

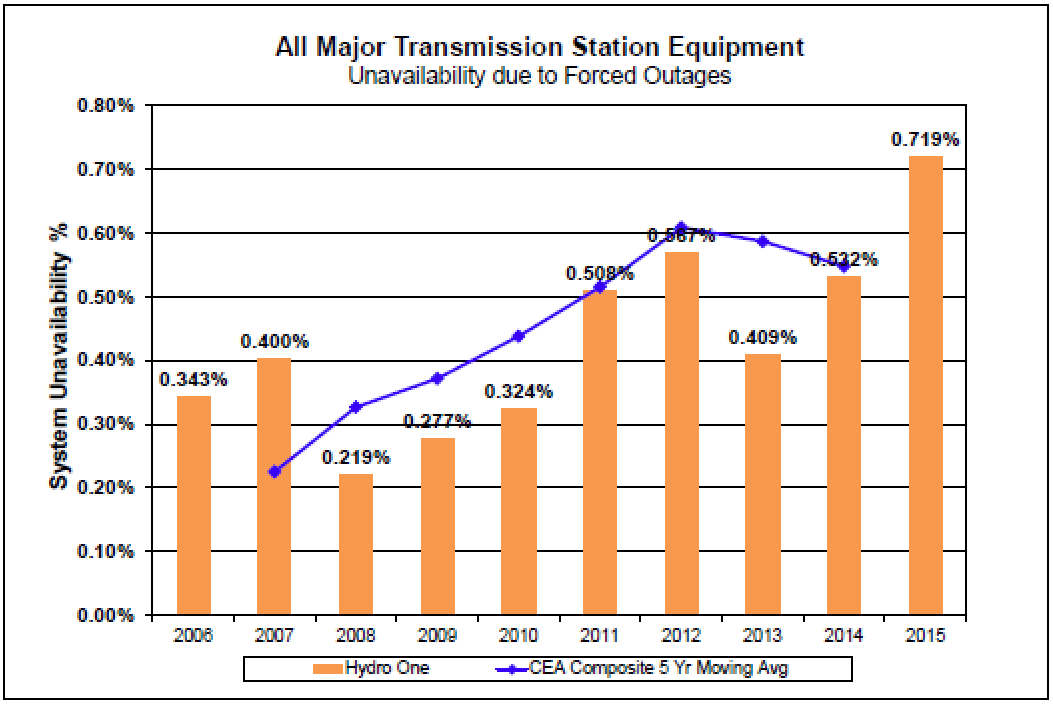


Figure 13: Unavailability of Major Transmission Station Equipment

Interrogatory:

a) Please comment on why RCE measures (Table 4, page 20 of B2-T1-S1) are declining (improving) from 2011-2015, while at the same time the ratio of unplanned station work to planned station work is increasing (worsening) (Table 6, page 23 of B2-T1-S1), and the Unavailability of Major Station Equipment due to forced outages (Figure 13, page 26 of B1-T1-S3) is increasing (worsening)?

b) Are these metrics pointing to different conclusions? Please explain in detail.

Response:

a) The RCE metric shows the trend over time between unplanned outages, gross assets and maintenance spending. The RCE metric is improving suggesting that Hydro One is prioritizing the correct investments, replacing or repairing assets that are likeliest to cause outages. It also suggests that Hydro One is maintaining a larger set of assets with a proportionately smaller amount of maintenance dollars.

Unplanned outages are only one factor in the equation and although unplanned work includes work that results from an unplanned outage, it also includes other demand-based work that does not require an outage. RCE deals with the number of outages, while Figure 13 deals with outage durations as well. The unavailability of major equipment is not always a result of a forced or unplanned outage due to Hydro One equipment issues. Hydro One equipment unavailability can also result from situations such as a request from a transmission-connected customer to enable maintenance on their equipment, the request of the IESO for voltage control, or as a control action for a planned outage on other assets.

As a result, these metrics do not necessarily correlate with each other.

b) The metrics are pointing to separate conclusions that do not correlate to each other. See response to part a) for further discussion.

Ontario Energy Board (Board Staff) INTERROGATORY #101

Reference:

Exhibit B2/Tab 1/Sch1 – Section 10.3.2: Project Delivery and Construction, pg. 23

"In Service Additions as a % of OEB approved budget: Selected to measure whether capital placed in service aligns with estimates developed during the planning process."

Table 6: Performance of Productivity Metrics

	Metric	2011	2012	2013	2014	2015
Work Execution	ISA as % of the OEB approved budget	95%	75%	90%	106%	85%
	% of budgeted work completed on or ahead of schedule	N/A	N/A	50%	85%	67%
	Engineering costs/ ECS Capital $	N/A	9.15%	9.14%	7.96%	8.23%
	Ratio of Stations unplanned work to planned work	36%	35%	38%	42%	41%

Interrogatory:

a) Please explain what happens to the capital projects that are not placed in service within the specified test period. Does the associated rate base addition roll over to the next filing?

b) Please explain in detail how Hydro One dealt with the 6% ISA spent in excess of the OEB approved budget in Year 2014 of Table 6.

c) Please explain the discrepancy between the values for ISA as % of the OEB approved budget and the % of budgeted work completed on or ahead of schedule in 2013, 2014 & 2015. What do these results indicate regarding project schedule management performance, given that a significant portion of forecast total annual expenditures were spent before capital year-end in each of these years?

Response:

a) Yes, capital projects that are not placed in service within the specified test period roll over to the next filing period. Hydro One reconciles variances with the OEB through the regulatory filing process.

b) As part of EB-2014-0140 settlement process, an in-service variance account was implemented to track the cumulative variance of in-service additions over 2014, 2015 and 2016. Hydro One managed within the approved portfolio for the test years and on an overall basis. The account balance is calculated on a cumulative basis over the three year period and no entries were made on an annual basis. There were minor adjustments on an annual basis as shown in Table 6 (above) however Hydro One is on target to achieve the cumulative approved budget.

c) Given the unpredictable nature of transmission projects, due to outage constraints and other externally driven factors, Hydro One may have to advance or delay the project completion date for causes that are not always in its control, including scheduling of outages by customers. The in-service addition measure accounts for this variability and measures the target and actual on an annual basis. Therefore if a project misses its budgeted completion date but remains within the calendar year it will be captured in the in-service addition measure. Hydro One's recent focus has been to align budget and actual in-service additions at the portfolio level but recognizes that there is an opportunity for improvement at a project level. There are several improvement initiatives underway including the Project Controls initiative to improve the risk management, scheduling and change management. For more information on these improvement initiatives please refer to Exhibit B1, Tab 4, Schedule 1.

Ontario Energy Board (Board Staff) INTERROGATORY #102

Reference:

None

Performance Category	Metric	Description
Asset Management	1. In-Service Capital Additions as % of OEB-Approved Plan 2. Capital Expenditures as % of Budget	*1. The measure is consistent with regulatory requirements of the Transmission Business, measuring the % of Capital In-Serviced relative to plan. The measure is not benchmarkable.* *2. Progress is measured as the ratio of actual total capital expenditures to the total amount of planned capital expenditures. The measure is benchmarkable.*

Interrogatory:

Could the metric highlighted in the above table be achieved by overspending on individual projects while other planned projects were deferred or eliminated?

If yes, please explain how Hydro One could modify this metric to show actual costs incurred per unit of budgeted project value delivered for a specific item (e.g.: actual cost per budgeted cost per transformer MVA, actual cost per budgeted cost per breaker by voltage class, actual cost per budgeted cost per km of new transmission by voltage class).

Response:

Yes, the Capital Expenditures metric can be met by overspending on individual projects while other planned projects were deferred or eliminated. In fact, it may sometimes be appropriate for such redirection or reprioritization to take place in any given year. The scorecard, including this metric, is intended to measure the transmitter's overall business performance. However, Hydro One has several controls in place to ensure that any such changes are made in an appropriate and managed fashion.

Hydro One monitors the capital expenditure and in-service addition forecasts on a twelve to eighteen-month horizon and is often required to advance or delay expenditures as a result of project challenges (e.g. outage constraints, external approvals, material delays, site conditions). Hydro One is required to manage within the approved budgets on a project basis as well as on a portfolio basis for capital expenditures and in-service additions. Hydro One has a robust variance identification and approval process that governs both spending and schedule variances against approved budget as described in Exhibit B1, Tab 2, Schedule 7. The Navigant total cost benchmarking study found that "Hydro One project estimates are relatively accurate" and that actual spend on average was slightly below the estimated budget. Please see Exhibit B2, Tab 2, Schedule 1, Attachment 1.

Ontario Energy Board (Board Staff) INTERROGATORY #103

Reference:

Exhibit B2/Tab 1/Sch1 Attachment 2 – Proposed Transmission Scorecard – Glossary of Measure Description, pg. 2

Performance Category	Metric	Description
Cost Control	1. Total OM&A and CAPEX/Gross Fixed Asset Value (%) 2. Sustainment Capital/Gross Fixed Asset Value (%) 3. OM&A/Gross Fixed Asset Value (%)	*1. Demonstrates Transmission cost effectiveness by comparing the ratio Total Capital and OM&A to Gross Fixed Asset costs. The measure is benchmarkable.* *2. Demonstrates Transmission cost effectiveness by comparing the ratio Sustainment Capital to Gross Fixed Asset costs. The measure is benchmarkable.* *3. Demonstrates Transmission cost effectiveness by comparing the ratio OM&A to Gross Fixed Asset costs. The measure is benchmarkable.*

Interrogatory:

a) For item 2, why was Sustainment OM&A not also included as a separate measure in addition to the Sustainment capital?

b) Did Hydro One consider how these cost control metrics could be used to show an impact on how revenue requirement or rates were reduced?

c) Did Hydro One consider a metric of OM&A per kWh transmitted? Why or why not?

Response:

a) Transmission sustainment OM&A represents almost all of the Transmission OM&A costs and as a result would follow the same trend as metric 3.

b) These metrics could potentially be linked to impacts on revenue requirement or rates in the future as the OM&A dollars have a direct impact on revenue requirement. However, as these are new metrics for the company, they will be refined over time to ensure that they drive the correct behaviour and effectively capture the impact of incremental efficiency improvements.

c) Please see the response to Exhibit I, Tab 1, Schedule 91 (2.0-Staff 91).

Ontario Energy Board (Board Staff) INTERROGATORY #104

Reference:

Exhibit B2/Tab 2/Sch1, p. 4

Table 1 provides the 8 best practice recommendations from the Transmission Cost Benchmarking Study and indicates the section of the evidence where the recommendations are addressed.

Interrogatory:

Please provide an expanded table which includes the specific actions taken by Hydro One in addressing each best practice, the specific evidence reference (exhibit/tab/schedule/page) and an estimate or target of the $ impact of the action taken.

Response:

Best Practice Recommendation	Impact	Exhibit	Actions
Reassess and adjust performance indicators across all levels of the organisation	Reduce costs, improve performance, build culture of continuous improvement	Cost Efficiency, Productivity and Key Performance Indicators B2-01-01, section 3.0, page 3 and section 5.0, page 7	Hydro One reviewed the applications of other utilities and has tried to leverage best practices in terms of KPI selection. Significant focus was placed on selecting KPIs which appropriately measure productivity in the deployment of capital and execution of operations, maintenance and administrative activities, in order to evaluate cost efficiency progress and the delivery of increasing customer value.
			As part of the scorecard development process, Hydro One took the opportunity to re-evaluate the use of KPIs in measuring performance across the organization and to develop more robust KPIs to facilitate performance management. Hydro One will continue to develop a performance management system in which KPIs for the lines of business are aligned with the OEB scorecard and business objectives, to actively drive cost reductions and productivity improvement.

Witness: Michael Vels

Best Practice Recommendation	Impact	Exhibit	Actions
Continue building on use of external resources for engineering, to create a pipeline of construction-ready projects	Reduced underspend, improved schedule performance	Work Execution Strategy – Capital B1-04-01, section 5.5, pages 12 and 13	The portion of the engineering portfolio completed externally has continued to grow over recent years, from roughly 14% in 2012 to roughly 25% in 2015. This has assisted in advancing engineering deliverables earlier in the project lifecycle to create an intentional backlog of construction-ready projects.
Manage the contingency budgets at the portfolio / corporate level	Frees funds for other priority investment opportunities	Work Execution Strategy – Capital B1-04-01, section 7.2.4, page 20	In assessing this recommendation, Hydro One is developing the tools necessary to analyze and manage contingency dollars at a portfolio level. Senior management discretion will determine the size of the contingency pool available to line managers and the establishment of a management reserve to enable strategic decision making.
Target a corrective maintenance spend that is ~25% of total corrective and preventative	Eventually anticipate better (lower cost) results if more is preventive than corrective.	O&M Work Execution Strategy C1-02-06, section 3.1.3, page 8 and section 3.2.3, page 11	Hydro One is aware of Transmission Total Cost Benchmarking Study recommendation with respect to ratio of corrective maintenance to total maintenance. At present time we are going through a process of rationalizing this target considering our system design philosophy and demographics of our asset base (which has been noted in the quoted Benchmarking Study). However, Hydro One is actively working on decreasing its corrective maintenance spend in stations. Initiatives include: • A new integrated planning and scheduling tool will facilitate more preventative work being completed in a timely manner to reduce the amount of corrective maintenance; • A decrease in corrective maintenance will also be realized with the replacement of assets in poor condition through the sustainment capital program; • Asset Management staff are working towards identifying the criteria for opting to replace equipment that has high maintenance costs through a more in-depth detailed analysis;
			Investment in a new integrated planning and scheduling tool will also assist in preventative maintenance being performed in a timely manner which should also reduce

Best Practice Recommendation	Impact	Exhibit	Actions
			corrective maintenance costs.
Work to reduce administrative costs	Eventually identify opportunities for cost reduction	Cost Efficiency, Productivity and Key Performance Indicators B2-01-01, section 10.2	Hydro One is currently investigating areas of opportunity to reduce administrative costs. The Procurement initiatives are part of this strategy along with IT initiatives to automate some reporting. Hydro One is also reviewing legacy processes of storing and backing up files and documents.
Allocate project management resources to improve effectiveness	Improve project cost and schedule performance	Capital Work Execution Strategy B1-04-01, section 7.1, page 18	Several organizational re-alignments have occurred to improve lateral integration throughout the capital project process, providing increased visibility for the management team to identify potential efficiencies. Examples include: Engineering resources have been consolidated into a single division; reallocation of Project Management resources to provide optimal support for projects; and Project Managers and Project Schedulers have been re-assigned to projects based on geographical zones rather than project magnitude and complexity.
Formalise a rolling two year capital budget and project portfolio and reporting framework, including projected earned value analysis	Provide the flexibility needed to reschedule projects within a two-year rolling window; improves ability to achieve planned annual investments	Capital Work Execution Strategy B1-04-01, section 7.2.1, page 19	As recommended in the Transmission Total Cost Benchmarking Study, Hydro One is working to formalise a rolling two-year capital budget and project portfolio with a reporting framework that includes parameters, authorizations and associated key performance indicators to promote continuous improvement.
Refresh formal driver training program	Reinforces driver safety and provides employees with focused behind-the-wheel training	Transmission Business Performance B1-01-03, section 3.2.2.2, page 9	Defensive driving and driver safety program training programs are being revised in 2016 and delivered to staff.

Ontario Energy Board (Board Staff) INTERROGATORY #105

Reference:

Exhibit A/Tab 3/Sch1– Section 2.3: Asset Needs Assessment, pg. 6

"Reliability risk is a metric that is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement. Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment investments. The reliability risk model is not used to identify specific asset needs and investments. Instead, these are determined by condition assessments and other asset-specific information, as described in Exhibit B1, Tab 2, Schedule 5."

Interrogatory:

Are failures of assets across all types, categories and voltage classes expected to impose similar consequence?

a) If no, does Hydro One consider the consequence of asset failure when evaluating Reliability Risk?

b) If yes, please provide details of the methodology and examples of quantitative evaluations that have been used in identifying specific projects in this application.

Response:

No, consequential impacts to the transmission network reliability (upon failure of an asset) differ depending on the asset types, and taking into consideration several risk factors for each. These risk factors are defined in the Asset Risk Assessment process evidence. Hydro One does consider the consequence of asset failures (as identified in the reliability risk model) and has incorporated the three most reliability impactive asset classes; transformers, breakers, and transmission lines in the model calculations.

Ontario Energy Board (Board Staff) INTERROGATORY #106

Reference:

Exhibit A/Tab 3/Sch1– Section 4: Transmission System Plan, pg. 13

Investment Category	EB-2014-0140		EB-2016-0160		Comparison between Filings	
	2017	2018	2017	2018	2017 Increase	2018 Increase
Sustaining	597.4	636.7	776.8	842.1	30.0%	32.3%
Development	148	116.4	196.4	170.2	32.7%	46.2%
Operations	44.4	25.2	25.4	30.8	-42.8%	22.2%
Common Corp Costs	58	60.4	77.6	79.1	33.8%	31.0%
Total Capital	**847.8**	**838.7**	**1076.1**	**1122.2**	**26.9%**	**33.8%**

Interrogatory:

a) Please confirm the following:

i) that the forecast sustaining capital expenditures in Test Years 2017 & 2018 are 30% and 32.3% higher than the corresponding Hydro One forecasts for sustaining capital expenditures in those years in the 2014 EB-2014-0140 filing.

ii) that the forecast development capital expenditures in Test Years 2017 & 2018 are 32.7% and 46.2% higher than the corresponding Hydro One forecasts for development capital expenditures in those years in the 2014 EB-2014-0140 filing.

iii) that the forecast operations capital expenditures in Test Years 2017 & 2018 are 42.8% lower and 32.3% higher respectively than the corresponding Hydro One forecasts for operations capital expenditures in those years in the 2014 EB-2014-0140 filing.

iv) that the forecast common corporate capital expenditures in Test Years 2017 & 2018 are 33.8% and 31% higher than the corresponding Hydro One forecasts for development capital expenditures in those years in the 2014 EB-2014-0140 filing.

b) Given the magnitude of these changes, please explain if Hydro One has obtained sources of material new information or changed evaluation methodologies between preparation of the 2014 application and this application.

i) If a result of new information, please explain why this information was not available to Hydro One at its last application.

ii) If as a result of new methodology, please explain what benefits this new methodology will produce to justify the additional costs.

Response:

a) and b) See Hydro One's responses below.

i) The increases described above for Sustainment capital forecasts are confirmed. They reflect new information regarding customer needs and preferences, reliability risk, the schedule of nuclear generation retirement and refurbishment, and emerging asset condition data.

- Hydro One's extensive customer engagement exercise took place in early 2016, as described in Exhibit B1, Tab 2, Schedule 2. It was Hydro One's first systematic attempt to consult customers specifically on their needs and preferences in a manner that could inform Hydro One's investment plan. Accordingly, the results of that undertaking were not available at the time of Hydro One's last rate application. Based on customer feedback regarding the importance of system reliability and mitigating reliability risk, Hydro One has attempted to maintain an appropriate balance between system reliability and corresponding rate impact.

- Hydro One's reliability risk model was developed in early 2016 as a planning tool that helps assess future system reliability, so information regarding reliability risk was unavailable at the time of Hydro One's last rate application. It reflects Hydro One's attempt to develop a model that provides a directional indication on the level of capital investment needed to reduce risk to system reliability. The reliability risk model is developed as a leading indicator for system reliability performance. The typical duration needed to scope and execute a transmission investment is between three to five years. Therefore, the key to maintaining top quartile reliability performance is to remediate reliability risk before it manifests itself as deterioration in SAIDI and SAIFI. The model is also used to cross-check the bottom-up determination of Sustainment capital spending levels needed to address asset needs described in Exhibit B1, Tab 2, Schedule 5.

- The schedule for Bruce Power and Ontario Power Generation's nuclear generation refurbishment and retirement was unclear in 2014 and, therefore, unavailable at the time of Hydro One's last rate application. This will significantly reduce base load generation availability between 2022 and 2030. Accordingly, Hydro One is taking steps to ensure transmission assets connecting the other generation assets are available to support system requirements.

- The increases are also attributable to new information regarding asset needs. At the time of Hydro One's last rate application, the urgency to address CP/COB insulator condition was not clearly understood. A 2016 testing report by Electric Power Research Institute ("EPRI") on Hydro One's CP/COB insulators validated that they have deteriorated to the point that replacement program needs to be accelerated to ensure safety and reliability. Please refer to Exhibit B1, Tab 3, Schedule 11, Investment Summary Document #S79. A new structure coating product recently became available, enabling modifications to Hydro One's tower coating method, making it more efficient. Together with a new technical assessment conducted with EPRI, Hydro One was able to develop a coating program to extend life of transmission structures in high corrosive zones, which is reflected in the current application. Refer to Exhibit B1, Tab 3, Schedule 11, Investment Summary Document #S76 for more details.

ii) The increases described above for Development capital forecasts are confirmed. The increased capital expenditures in 2017 and 2018 are primarily due to unexpected delays in the Clarington TS and the Supply to Essex County Transmission Reinforcement projects, as well as the addition of two new load connection projects to the forecast (Hanmer TS and Runnymede TS). Details on these projects are available in Exhibit B1, Tab 3, Schedule 11, Investment Summary Documents #D01, D14, D18, and D19 respectively.

iii) Hydro One confirms that the Operations capital forecasts for 2017 and 2018 are 42.8% lower and 22.2% higher, respectively, than the forecasts provided in its EB-2014-0140 filing. (Note that the percentage change for 2018 is mistyped in the question.) The decrease in 2017 Operation capital expenditures can be attributed to reprioritization of the following investments that were referenced in the EB-2014-0140 application: mobile radio replacement, the telemetry expansion program, the distance to fault - fault locating program, wireless station cameras and the wide area network outreach program. The increase in 2018 Operations capital expenditures can be attributed to: (a) a shift in the work schedule and scope of the Integrated System Operations Centre project; and (b) the additional sustainment investment in station local control equipment. Details on these investments are provided in Exhibit B1, Tab 3, Schedule 11, Investment Summary Documents #O01 and #O02, respectively.

iv) It is assumed that this question compares Common Corporate capital forecasts provided in the current application and in the EB-2014-0140 application. The increases described above are confirmed. The increases are largely attributable to changes in information technology ("IT") forecasts and transport, equipment and service equipment ("TWE") forecasts driven by new information.

- In the EB-2014-0140 application, IT estimates for 2017 and 2018 were based on class 'D' estimates (+50% accuracy) premised on a comparable business case for a medium size, complex SAP implementation of new functionality and enhancements. The estimates provided in the current application are based on more mature investment plans, meaning better defined requirements, proof-of-concept and/or actual vendor quotes. Also, emerging business needs to address process inefficiencies have driven additional investments not reflected in the 2014 application. For example, certain treasury, finance and human resource functions will be integrated into the existing enterprise SAP system to minimize manual tasks and promote a streamlined, more efficient enterprise environment. As part of Hydro One's "Security Event and Incident Management" upgrade and refresh initiative, a third-party assessment was commissioned in 2015 to review current design and practices, and make recommendations for improvements as needed. This resulted in a new investment in IT security as detailed in Exhibit B1, Tab 3, Schedule 6.

- For TWE, the cost increases are associated with a small increase in budget and an increase in costs allocated to the transmission business, reflecting the increased use of fleet assets for transmission work. Please refer to page 7 of Attachment 1 to Exhibit B1, Tab 3, Schedule 9 for a summary of the allocation approach for TWE.

Ontario Energy Board (Board Staff) INTERROGATORY #107

Reference:

Exhibit B1/Tab3/Sch1

Interrogatory:

Has any information come forward, since the application was submitted (particularly for the 2016 Bridge year), to indicate that 2015 or 2016 capital expenditure forecasts require amendment? Are all projects expected to be in rate base for the test years, still expected to be in rate base?

If some of the projects that are listed in Table 2-27 are not expected to be in-service in 2016 and as a result will not be added to the 2016 Rate Base, please identify all such projects, the associated capital expenditure and the expected in-service date.

Response:

No information has come forward that will materially impact the 2016 bridge year.

At this point, the only project that is not expected in be in-serviced in 2016 is Copeland MTS - Build line connection for Toronto Hydro ($2.7 million in 2016). Hydro One has just been notified by Toronto Hydro that the work to be done by Toronto Hydro has been delayed. The completion of this project by Hydro One is contingent upon Toronto Hydro’s work; therefore Hydro One will not be able to place Copeland MTS in-service till spring 2018. This project is fully recoverable from Toronto Hydro and therefore the delay will not impact Hydro One’s revenue requirement (or in-service additions).

The only project that will not be moving forward and will impact test year rate base is Lisgar (Project D16). The project was planned with an in-service of 2018 with a net project capital total of $10 million. Cash flows were $7.5M and $2.5M in 2017 and 2018, respectively. Please refer to OEB Staff #74 for more detail.

Ontario Energy Board (Board Staff) INTERROGATORY #108

Reference:

Exhibit C1/Tab 2/Sch 1

Interrogatory:

a) Please identify what improvements in services and outcomes Hydro One's customers will experience in 2016 and during the subsequent 2017- 2018 term as a result of OM&A spending in 2016, 2017 and 2018?

b) How has Hydro One communicated these benefits and the associated costs to its customers, and how did customers respond? Please provide some examples, including a synopsis of any customer feedback. If no communications took place, please explain why not.

Response:

a) As noted in Exhibit C1, Tab 2, Schedule 1, OM&A expenditures are declining in each year for the period 2016 to 2018. Given that the overall OM&A trend is declining and the majority of OM&A expenditures are Sustainment expenditures, improvements in services and outcomes are limited and targeted. As noted in section 4.1 of Exhibit B1, Tab 2, Schedule 4, Hydro One has relied on maintenance programs to extend the lifespan of assets by continually addressing asset condition deficiencies, where practical, as a means of deferring large capital expenditures. Thus, improvements are limited to targeted maintenance of assets as noted in Exhibit B1, Tab 2, Schedule 4 and minor enhancements to some customer communications.

b) Given the very limited nature of improvements in services and outcomes, there has been no overall communication of benefits and associated costs to customers. It is an integral part of Hydro One's maintenance work on specific facilities to communicate expected outcomes to impacted customers and coordinate efforts with impacted customers.

Ontario Energy Board (Board Staff) INTERROGATORY #109

Reference:
Exhibit C1

Interrogatory:
Has any information come forward, since the application was submitted, particularly as the Bridge year evolves, to indicate that 2016, 2017 or 2018 OM&A forecasts require amendment? If so please provide an update with any rationales for changes.

Response:
Hydro One filed blue page updates for 2017 and 2018 OM&A on July 20, 2016 to revise the pension expense, back out B2M LP costs that were inadvertently included, and to revise OEB fees allocated to Transmission. The result was a reduction to previously filed OM&A. The OM&A filed for the bridge year did not include equivalent adjustments; however some of these updates did impact 2016 OM&A. The impacts of these adjustments reduce OM&A as follows: $11.0M for pensions (which is captured in the related variance account (see Exhibit F1, Tab 1, Schedule 1), and $0.2M for B2M LP costs. OEB costs for bridge year 2016 have not materially changed from the filing. The cost decreases outlined for 2017 and 2018 are primarily a result of a Board study that decreased Hydro One's OEB Cost Allocation. While the allocation decrease was implemented in Q2, 2016, the resulting decreases mid-year were mitigated by an initial increase in Q1 of 2016.

Aside from the changes noted above, for 2016, there are no material differences that Hydro One would amend relative to the filing for the test years. As forecasts are periodically refined, it is not anticipated that Hydro One would seek recovery of any upward movement in OM&A costs should they occur.

Ontario Energy Board (Board Staff) INTERROGATORY #110

Reference:

Exhibit C1/Tab 2/Sch1 pp. 6-7

Interrogatory:

Tables 2 and 3 show the $20.0 million reduction negotiated in the EB-2014-0140 settlement agreement for 2015 and 2016 respectively.

Did the $20 million OM&A settlement reduction in each of those years cause any negative system performance or service reliability results?

a) If yes, please provide quantified details and explain how Hydro One was able to reduce the budgets by a further $4.6 million in 2016 without exacerbating those negative results.

b) If no, please describe and quantify any negative system performance or service reliability impacts that would result from a similar proportional reduction in OM&A budgets for Test Years 2017 & 2018.

Response:

No.

a) The $4.6M additional reduction is largely due to the $4.1M reduction in taxes, which is unrelated to the work programs discussed below.

b) The $20M reduction in OM&A budget negatively impacted power equipment maintenance, protection maintenance, and standards development work. While these changes in OM&A budgets did not result in an immediate observable impact on reliability performance measures, these reductions in maintenance may impact future reliability. Furthermore, it is likely that additional reductions in OM&A will negatively impact SAIDI and SAIFI in future years.

Witness: Mike Penstone

Ontario Energy Board (Board Staff) INTERROGATORY #111

Reference:

Exhibit C1/Tab2/Sch2/p.10

Table 10 shows spending plans for environmental management with substantial increases in PCB and Transformer Oil Leak Reduction areas:

Interrogatory:

a) Please explain why PCB Retirement and Waste Management and Transformer Oil Leak Reduction costs are projected to increase significantly in the test years, while Hydro One is simultaneously accelerating the rate of capital expenditures for transformer replacements, with the notional benefit of reducing operating costs.

b) Please confirm that Hydro One prioritizes transformer replacements to ensure that those transformers that are in the worst condition are replaced first. Please identify all exceptions and provide reasons for prioritizing the replacement of transformers that are not in the worst condition.

c) Hydro One indicates that it will be increasing spending in the test years on PCB Retirement and Waste Management in order to ensure meeting the 2025 Environment Canada deadline for PCB retirement in advance. Why is Hydro One spending at levels to achieve compliance before the deadline?

Response:

a) PCB retirement and waste management applies to all the oil filled equipment in the system. Oil filled equipment includes transformers, bushings, breakers, instrument transformers, reactors and capacitors. Environment Canada regulations require all oil filled equipment to contain less than 50ppm PCB content by 2025. This requires Hydro One to test approximately 20,000 pieces of oil filled equipment and address any non-compliant equipment through retro-filling or replacement. The increase in OM&A funding is due to the significant amount of work required to achieve compliance.

   The funding for transformer oil leak reduction program is consistent with historical spending levels and is required to mitigate reliability and environmental risks.

b) Please refer to Board Staff response #31, part (f).

c) Hydro One is targeting a date of 2023 in order to provide sufficient scheduling contingency to mitigate risks due to weather, outage constraints, customers, resources, or other issues which could potentially delay the on-time completion of this project.

Ontario Energy Board (Board Staff) INTERROGATORY #112

Reference:
Exhibit C1/Tab2/Sch2/p.17

Interrogatory:
Hydro One indicates that its system continues to age which correlates to an increase in maintenance requirements, yet the corrective maintenance spending is declining from 2014 and 2015 levels (in the two test years). Why are these budgeted levels not increasing as the system ages?

Response:
The corrective maintenance spending in 2014 was $27.6M and in 2015 it was $28.7M. The forecast corrective maintenance spending for 2017 and 2018 test years are $27.5M and $27M which is similar to 2014 and 2015. The ongoing focus on station sustainment investments has provided some relief to the upward pressure on corrective maintenance costs. Improvements in scheduling and bundling corrective work have also helped to reduce costs.

Ontario Energy Board (Board Staff) INTERROGATORY #113

Reference:

Exhibit C1/Tab2/Sch2/p.25

Interrogatory:

Table 7 shows that Protection, Control, Monitoring and Metering equipment OM&A increases from $19.5 million in 2015 to $23.3 million by 2018, an increase of 10.5% over 3 years. Please provide more detail on the work programs that contribute to this increase and why those programs require such funding increases.

Response:

OM&A spending covers routine maintenance, corrective activities and support for protection and control equipment. The increase in OM&A expense is largely attributable to planned corrective activities where there is an increase of $3.4 million in 2017 and $3.6 million in 2018 compared to the bridge year. Deferral of correctives is unfavourable for the operation of the power system. It can also lead to violation of the mandatory NERC standard PRC-004, which requires entities to establish and complete corrective plans related to protection system misoperations.

The increases in spending are required to address several corrective initiatives undertaken to ensure reliable and dependable operation of the protection system. Specifically, the following identified deficiencies that are being addressed include: modification of transformer protection relays settings for 2nd Harmonic energization issues, correction of restricted ground fault settings and line backup supervision and resolving a manufacturer defect affecting a select population of relays. Below is a table that shows the number of misoperations reported. The planned correctives are to proactively prevent similar future misoperations across HONI protections systems.

Causes of Misoperation	Total Number Reported
Misoperations due to 2nd Harmonics	16
Misoperations due Restricted Ground Fault	2
Misoperations due to Line Back Up	55
Misoperations due to Manufacturer Defect	14

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #114

Reference:

Exhibit C1/Tab2/Sch2/p.41 and Exhibit B2/Tab1/Sch1 p.18

Table 11 shows Vegetation Management costs over the test year period. Brush Control costs grow from $17.8 million in 2015 to $21.5 million in 2018, an increase of 21% over 3 years. At page 44, Hydro One indicates that the increase is due to the requirement to perform additional necessary brush control.

Interrogatory:

a) What are the specific reasons for the increase in brush control costs over this period?

b) At the second reference in Table 3, Hydro One provides unit cost metrics for forestry and lines work, covering 2012 to 2015. Please provide Hydro One's forecast or targets for the metrics on this table for 2016, 2017 and 2018.

c) What are the clearing cycles employed by Hydro One that it considers are appropriate for its system and how it has determined that these cycles provide a cost-effective and sustainable level of reliability? Please provide examples to illustrate the varying cycle times.

Response:

a) The proposed expenditure for brush control maintenance in 2017 and 2018 is consistent with historical spending levels.

b)

Line of business	**Unit Matric**	**2016**	**2017**	**2018**
Forestry	$ /brush control cost per hectare	12,500	11,500	11,800
	$ /line km cleared	3,100	2,800	2,800
Provincial Lines	$ /wood pole condition assessment	363	381	389
	$ /wood pole replacement	47,000	47,000	47,000
	$ /115 kv tower coated (average)	25,500	25,500	25,500
	$ /230 kv tower coated (average)	40,500	40,500	40,500
Network operating (only)	$ /cable locate	16	16	16

Witness: Chong Kiat Ng

c) Please refer to Exhibit C1, Tab 2, Schedule 2, section “Line Clearing” on page 42 for clearing cycles employed. Hydro One vegetation management cycles have been established based on historical experience to maintain vegetation related outages at the current level.

Ontario Energy Board (Board Staff) INTERROGATORY #115

Reference:

Exhibit C1/Tab2/Sch2/p.45

Table 12 shows Overhead Line Maintenance costs over the test year period showing an increase from 2015 to 2018 of over 30%. It appears this increase is driven by Preventative Maintenance and Asset Assessment activities (increasing 97% over the 3 year period). On page 50 Hydro One indicates that costs are higher as it needs to conduct more condition assessments on deteriorating assets.

Interrogatory:

Please provide further specific rationale for the increase in costs using specific examples for illustration.

Response:

Due to an aging asset fleet, there is an increasing demand on condition assessment due to the assets deteriorating condition.

For example, as illustrated in figure 24 of Exhibit B1, Tab 2, Schedule 6, 31% of the conductor fleet (approximately 10,000 circuit km of conductor) requires condition assessment. Hydro One intends to complete these assessments in the next 5 years, or approximately 2,000 km of conductor per year.

In addition, approximately 50% of shieldwire fleet (approximately 17,000 km of shieldwire) requires condition assessment. It is proposed to complete these assessments in the next 5 years, approximately 3,500 km of shieldwire per year. These assessments are necessary to determine which of the shieldwire has reached end of life and require replacement.

Ontario Energy Board (Board Staff) INTERROGATORY #116

Reference:

Exhibit C1/Tab2/Sch6/pp. 5 - 17

Interrogatory:

Hydro One lists a number of productivity improvements and business practices that are intended to increase efficiency. Has Hydro One quantified these improvements in terms of OM&A savings over the 2016 to 2018 period? Please provide a forecast of the savings that may be expected through each of these process improvements.

Response:

2016 Productivity Savings

OMA only

Cost Efficiency Initiative	2016 YE Forecast	2017 YE Forecast	2018 YE Forecast
Cable Vault Inspection with cameras	$35,000	$35,000	$35,000
Inhouse retorques on light vehicles	$40,000	$40,000	$40,000
Regular used materials in inventory rather than shopping	$250,000	$250,000	$250,000
TWHQ Stations	$375,000	$375,000	$375,000
Stradle Hoist Usage - Instead of crane contractor	$95,000	$95,000	$95,000
Recondition oil - Instead of purchasing new	$400,000	$400,000	$400,000
Outsourcing G&S BGIS	$300,000	$300,000	$300,000
Wrench Time Studies	$0	$400,000	$1,000,000
OT Reductions on Correctives/Prev 1% reduction on 11% 2015	$1,000,000	$1,000,000	$1,000,000
	$2,505,000	$2,905,000	$3,505,000

Witness: Andy Stenning

Ontario Energy Board (Board Staff) INTERROGATORY #117

Reference:

Exhibit C1/Tab 3/Sch2, p. 3

Hydro One indicates that "The Inergi Agreement provides for optional benchmarking reviews of fees by an independent third party, the costs of which are borne equally by Hydro One and Inergi."

Interrogatory:

Has Hydro One or Inergi called for a benchmarking review since the contract was initiated on March 15, 2015? Is Hydro One planning any such reviews it the near future? If not, is Hydro One satisfied that the contract is achieving its cost effectiveness and operational goals?

Response:

Given that the contract commenced as of March 1, 2015 following a competitive procurement process, Hydro One determined that it did not need to execute its benchmarking option in the initial year of service. Hydro One is not considering executing this option in the near future as Hydro One is satisfied that the contract is achieving its cost effectiveness and operational goals.

Ontario Energy Board (Board Staff) INTERROGATORY #118

Reference:

Exhibit C1/Tab 3/Sch2, p. 3

Hydro One discusses Performance Indicators (PIs), how they are regularly measured and how they are adjusted upwards annually to drive continuous improvement. In addition Hydro One indicates that the Inergi contract life-to-date as of February 2016 met or exceeded 94% for all SOWs with regard to the PIs.

Interrogatory:

Please provide a report of actual performance for the PIs, the monthly, quarterly and yearly measures, and an indication of the actual upward adjustments initiated.

Response:

This response has been filed confidentially with the Ontario Energy Board. Attachment 1 contains a summary description of the response.

Ontario Energy Board (Board Staff) INTERROGATORY Attachment 1

Hydro One has filed in confidence with the OEB a summary of Inergi LP's actual performance of the PIs (monthly, quarterly, and yearly measures) for the period March 2015 to February 2016. The summary categorizes the PIs and provides the following information: the number of PIs in each category; the number and percentage of PIs for which Inergi met performance expectations; and the number of PIs for which Inergi missed target or minimum performance levels. As an explanatory note in the summary, Hydro One indicates how many PIs were adjusted upward to achieve continuous improvement as per the Inergi Agreement, effective as of January 1, 2016.

Ontario Energy Board (Board Staff) INTERROGATORY #119

Reference:

Exhibit C1/Tab 3/Sch2, p. 12, Appendix B

Interrogatory:

This table of total Inergi contract fees over the 2013 to 2014 period, shows a marked drop in fees from 2015 to the 2016 Bridge year. What are the primary reasons for this significant 21% reduction in fees?

Response:

Under the new Inergi Agreement, Inergi provides Base Services based on a declining fee structure, which makes up approximately 3% of the decrease. The majority of the reduction is associated with a decrease in planned project work of approximately 18%.

Ontario Energy Board (Board Staff) INTERROGATORY #120

Reference:
Exhibit C1, Tab 3, Schedule 2, p. 5

Interrogatory:
Regarding the BGIS services agreement which was effective February 19, 2015:

Please provide Hydro One's rationale for entering into such an agreement with an emphasis on the expected cost savings over the 10 year period. In addition, please provide a report of client satisfaction and the regular reviews as indicated on page 7 of the schedule.

Response:
Hydro One entered into the BGIS services agreement to achieve a significant reduction in total costs in respect of the scoped facilities management, accommodation activities and related maintenance and repair work at its operations centres, stations, administrative facilities and rights of ways which are considered non-core to Hydro One's business. In addition to lower operational costs, the agreement provides for stable, defined market level services over its 10 year term by leveraging industry best practices and offers significant potential to increase work accomplishments and internal customer satisfaction as a result of this work being BGIS's core business. Through the agreement, Hydro One expects to realize costs savings in excess of $80 million over the 10-year term of the agreement, as compared against Hydro One's historical OM&A spend.

Internal client satisfaction is identified as one of the key performance measures in the agreement. Client satisfaction is measured by way of formal survey completed by internal clients who have requested services. The survey seeks feedback on the quality, timeliness and professionalism of the work performed to determine overall satisfaction. Surveys commenced in May of 2015. The customer satisfaction results obtained to date are set out below.

Service Request Customer Satisfaction Survey Results	
Quarter	**Results**
Q2 2015 (May & June)	80%
Q3 2015 (July – Sep)	85%
Q4 2015 (October – Dec)	79%
Q1 2016 (Jan – Mar)	75%
Q2 2016 (Apr – June)	83%

Witness: Gary Schneider

In accordance with the agreement, Hydro One's relationship is managed by means of a robust governance structure which includes rigorous performance monitoring and oversight through meetings at regular intervals at the executive (bi-annual), governance (quarterly), and operational levels (monthly). Areas of focus at these meetings include a review of performance against the key performance indicators and critical service levels, benchmarking, budgeting and goal setting, risk identification and management, and the development of continuous improvement initiatives.

Ontario Energy Board (Board Staff) INTERROGATORY #121

Reference:

Exhibit C1/Tab 3/Sch3, p. 2 (Table 1)

Table 1 provides the Tx allocation for the CCFS costs for the 2017 and 2018 test years only.

Interrogatory:

a) Please provide the Tx allocation for the 2012 to 2016 period as well.

b) Please provide similar breakdown for Exhibit C1/Tab3/Sch4 pg. 2 Table 1.

c) Please provide similar breakdown for Exhibit C1/Tab3/Sch5 pg. 1 Tables 1-7.

d) Please provide similar breakdown for Exhibit C1/Tab3/Sch7 pg. 1 Tables 1-2.

Response:

a) Please see the requested table for Exhibit C1, Tab 3, Schedule 3 below.

Table 1: CCFS ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
Corporate Management	2.5	2.1	2.7	2.8	4.0
Finance	20.7	25.1	23.2	22.9	23.3
People and Culture	6.0	6.5	7.0	6.8	8.4
Corporate Relations	5.3	6.5	9.4	7.7	8.7
General Counsel	4.9	5.4	4.9	5.0	5.5
Regulatory Affairs	9.0	10.3	9.9	10.5	10.2
Security Management	1.5	1.6	1.7	2.0	2.4
Internal Audit	2.3	2.1	2.4	2.6	3.2
Real Estate and Facilities	28.3	28.0	31.8	35.5	33.1
Total CCF&S Costs	80.5	87.7	93.1	95.7	98.9

b) Please see the requested table for Exhibit C1, Tab 3, Schedule 4 below.

Table 1: Planning Expenditures ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
System Investment	26.3	25.2	26.1	21.1	25.4
Asset Stewardship & Strategies	6.1	6.5	6.5	9.9	11.1
Total	**32.3**	**31.8**	**32.6**	**31.0**	**36.6**

c) Please see the requested tables for Exhibit C1, Tab 3, Schedule 5 below. (Note that Table 3 contains a description of strategic information technology systems and no cost information.)

Table 1: Information Technology Summary of OM&A Expenditures ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
Sustainment	35.5	33.4	31.6	30.6	32.0
Development	3.7	4.1	3.2	5.3	7.2
Business Telecom	10.6	11.0	9.5	8.3	9.9
IT Security	-	-	-	-	-
IT Management & Project Control	10.5	11.9	10.5	10.9	12.3
Cornerstone	0.4	0.7	0.4	0.0	-
Total	**60.7**	**61.1**	**55.2**	**55.1**	**61.4**

Table 2: OM&A Sustainment of Information Technology ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
Base IT Sustainment Services	29.5	26.8	24.7	23.8	23.8
3rd Party Contracts	6.0	6.6	6.9	6.8	8.2
Total	**35.5**	**33.4**	**31.6**	**30.6**	**32.0**

Table 4: Development Expenditures ($Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
Enhancements	2.0	2.5	1.7	2.0	2.4
Upgrades	1.7	1.6	1.5	2.7	3.1
Impact of Capital Projects	-	-	0.0	0.6	1.7
Total	**3.7**	**4.1**	**3.2**	**5.3**	**7.2**

Table 5: IT Security ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
IT Security	**-**	**-**	**-**	**-**	**-**

Table 6: Business Telecom OM&A Expenditures ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
Operations and Carrier Management	3.3	4.2	3.9	3.6	4.0
Field Services	1.6	1.4	1.3	0.9	0.9
Voice and Data Network Services	5.7	5.4	4.3	3.8	4.5
Mobility Services [1]	-	-	-	-	0.5
Total	**10.6**	**11.0**	**9.5**	**8.3**	**9.9**

[1] Mobility Services costs moved to IT from each business division's non-labour costs starting in 2016

Table 7: IT Management & Project Control Expenditures ($ Millions) 2012-2016

Description	TX 2012	TX 2013	TX 2014	TX 2015	TX 2016
IT Management	10.0	11.3	10.0	10.3	11.5
Project Support and Control	0.5	0.6	0.5	0.6	0.8
Total	**10.5**	**11.9**	**10.5**	**10.9**	**12.3**

d) The tax and payment information in Tables 1 and 2 represent a 100 % allocation to transmission. Please refer to Exhibit C1, Tab3, Schedule 7.

Ontario Energy Board (Board Staff) INTERROGATORY #122

Reference:

Exhibit C1/Tab3/Sch3/p. 2

Hydro One shows an increase of over 300% in Corporate Management Costs from 2015 to 2018, from $5.4 million to $22.1 million. Hydro One indicates that higher corporate management costs are due to increases in compensation.

Interrogatory:

a) Please provide additional detail on the components of this compensation increase.

b) Please justify the reasoning for the necessity for the magnitude of these increases.

Response:

a) and b) Please see Exhibit I, Tab 4, Schedule 12.

Witness: Glenn Scott

Ontario Energy Board (Board Staff) INTERROGATORY #123

Reference:

Exhibit C1/Tab3/Sch3/p. 20

Hydro One shows an increase in Internal Audit and Risk Management costs in the range of 50% from 2015 to 2018. The rationale provided is that rotational resources were made permanent and increased need for Internal Audit capabilities.

Interrogatory:

a) Which originating departments reduced costs as resources were transferred to Internal Audit and what were the reductions in cost?

b) Why did Internal Audit capabilities need to be increased? Please provide specific examples.

Response:

a) For the most part, a few temporary resources were made into permanent positions and new permanent positions were created to fulfill the resource needs. Temporary positions are budgeted at lower cost than permanent positions as they do not have the long-term burdens associated. One position was moved from the Corporate Controller group, reducing its budget by approximately $230,000.

b) Resource increases were needed to address a backlog in audit work and complete the total number of audits planned.

Ontario Energy Board (Board Staff) INTERROGATORY #124

Reference:
Exhibit C1/Tab 4/Sch1, p. 4 and Figure 2

Interrogatory:
Hydro One indicates that from 2011 to 2015 about 20 to 25% of those employees that are eligible to retire; actually retire. Please provide a forecast for 2016 to 2018 to show projected retirements over that period. Is there any reason for Hydro One to expect a higher retirement uptake in future years?

Response:
Forecasting future retirements is challenging due to the very personal nature of this decision. Based on a 4 year average of retirement uptake, Hydro One can expect future retirements to be:

Year	Forecasted Retirement
2016	203
2017	209
2018	192

There is no reason at this time for Hydro One to expect the retirement percentage uptake to change in future years.

Witness: Keith McDonell

Ontario Energy Board (Board Staff) INTERROGATORY #125

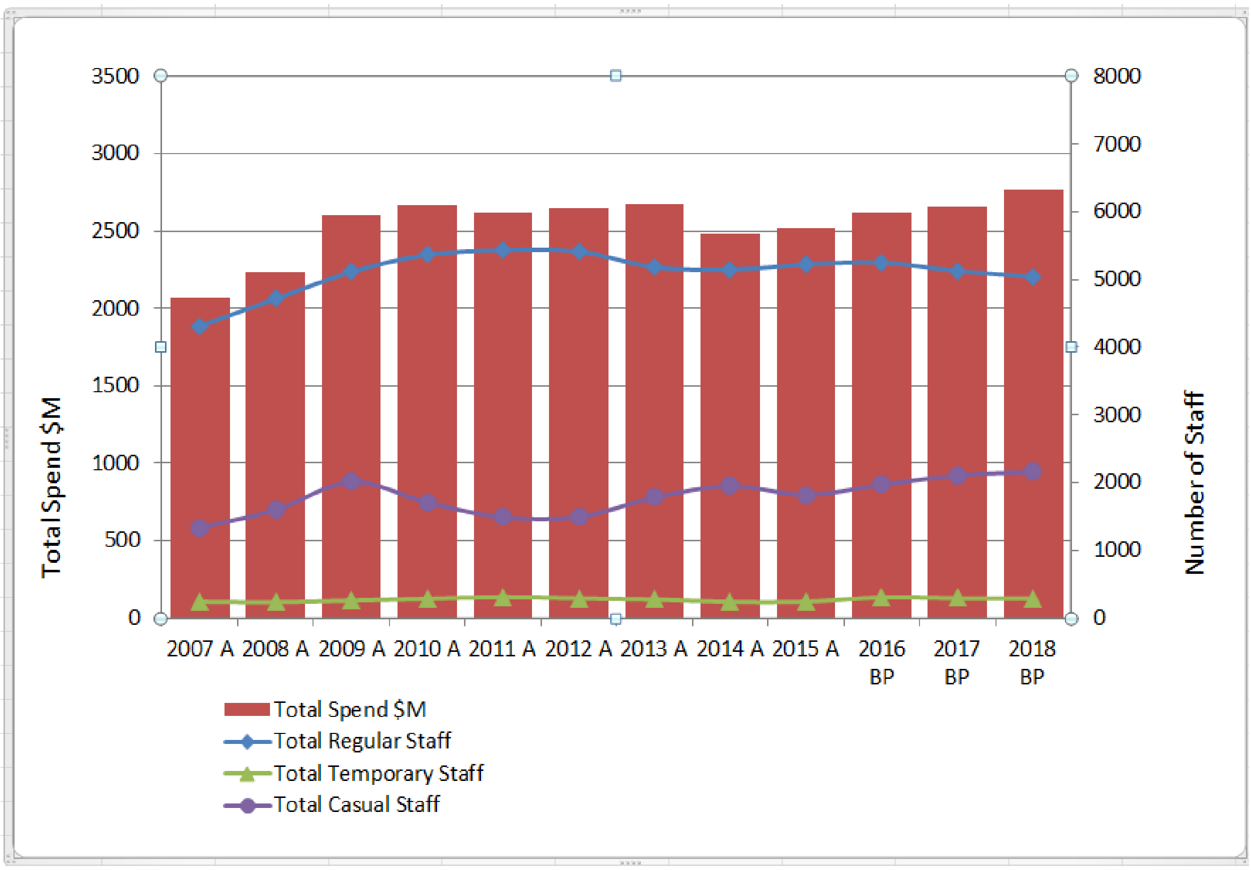
Reference:

Exhibit C1/Tab 4/Sch1, p. 7 and Figure 4

Interrogatory:

Please provide a similar graph which expands to include separate lines for regular, temporary and casual employees. In addition, please define the term, "Total Spend".

Response:



Total spend is the total capital and OM&A spend for both Transmission and Distribution work program in a year.

Ontario Energy Board (Board Staff) INTERROGATORY #126

Reference:

Exhibit C1/Tab 4/Sch1, p. 11 and Table 1

Interrogatory:

Why, in 2016, is Hydro One reducing the levels of apprentice hiring for both Lines and Stations from 2010 levels? Please provide a justification in light of the concerns cited with retirements and expanded work program. What is Hydro One's forecast of this apprentice hiring in 2017 and 2018?

Response:

Due to lengthy training requirements, Hydro One hires apprentices well in advance of the forecasted retirements. Apprentices hired in 2012 are now trained to replace retirements occurring in 2016. For Provincial Lines, the apprentice pool is maintained to keep approximately 350 apprentices in the talent pool at any given time. Based on projected future retirement and work program forecasts, Hydro One hired 80 apprentices earlier in 2016 and a further 16 will be hired in the fall of 2016 for a total of 96 new apprentices in 2016.

Stations electrical apprentice hiring is less in 2016 due to lower than expected retirements in the electrical trade classification.

Forecast apprentice hiring in 2017 and 2018 are:

Lines: 112 and 96 apprentices
Stations: 15 and 15 apprentices

Ontario Energy Board (Board Staff) INTERROGATORY #127

Reference:

Exhibit C1/Tab 4/Sch1, p. 22

Hydro One indicates that in 2015, approximately 57% of the total transmission capital work was performed by casual, unionized employees.

Interrogatory:

a) Can Hydro One provide an estimate of the savings that are generated by this level of casual labour?

b) What are the additional costs, if any, to Hydro One for employing this level of casual labour (both financial and operational)?

c) Will Hydro One continue to increase this percentage in the 2017 and 2018 test years?

Response:

a) Hydro One is obligated through collective agreements to assign work to the various unions based on their work jurisdiction entitlements. Since there are no options to assign work to another union, there are no savings.

b) See response to part a).

c) See response to part a).

Ontario Energy Board (Board Staff) INTERROGATORY #128

Reference:

Exhibit C1/Tab 4/Sch1, p. 24

Interrogatory:

Hydro One indicates that collective bargaining has resulted in share grants as part of total compensation packages for the PWU and the Society. These share grants were offset by below average base wage increases. Please specifically define the 'below average' wage increases and indicate what the total increase in compensation would be when share grants are accounted for on April 1, 2017 for the PWU and April 1, 2018 for the Society.

Response:

In 2015, Hydro One negotiated lower than norm base wage adjustments with both the PWU and Society as part of an overall package that contained share grants for some PWU and Society represented employees. Specifically,

	2015	**2016**	**2017**
PWU	1% base adj.	1% base adj.	1% adj.
Society	0.5% base adj.	0.5% base adj.	0.5% base adj.

Survey data for Forecast and Actual Base wage adjustment:

Survey	**2015 Forecast**	**2015 Actual**	**2016 Forecast**	**2016 Actual**	**2017 Forecast**
Conference Board	2.0%	1.8%	1.9%	-	-
Canadian General Industry	3.0%	2.6%	2.7%	2.4%	2.6%
Ontario based Organizations	2.9%	2.6%	2.6%	2.4%	2.6%
Canadian Energy Sector	2.8%	2.2%	1.2%	1.5%	1.4%

The share grant costs for 2017 and 2018 are:

2017: $3,540,302

2018: $ 4,745,181 for both PWU and Society Share Grants

Ontario Energy Board (Board Staff) INTERROGATORY #129

Reference:

Exhibit C1/Tab 4/Sch1, p. 25

Hydro One indicates that total compensation for regular employees increased by 1.27% per year over the 2013 to 2018 period.

Interrogatory:

a) What was the increase over the same period for temp staff and casual staff over the same period?

b) Please explain the statement, "The attachment does not reflect the revenue requirement for compensation for this Application". Are the figures that appear under 2017 and 2018 not indicative of compensation related to this application?

Response:

a) The increase (decrease) over the same period for temporary employees is -0.13% per year and +6.8% per year for casual employees.

b) The compensation data for 2017 and 2018 are indicative of compensation related to this application, however the revenue requirement related to compensation costs are within the overall OM&A. The compensation data in the payroll table reflects the year end compensation for all Networks employees (Distribution and Transmission) on payroll on December 31st of each year. The dollar values for 2016, 2017 and 2018 are forecasted numbers based on actual YE 2015 compensation totals. The payroll table is intended to show trends in compensation for Network employees.

Ontario Energy Board (Board Staff) INTERROGATORY #130

Reference:
Exhibit C1/Tab 4/Sch1, p. 26

Interrogatory:
Why did Hydro One not complete an update of the Mercer Compensation Benchmarking study for this application? If the study was not updated, can Hydro One provide similar information on how its compensation levels compares with others in the industry?

Response:
In 2015, Hydro One negotiated a new three-year collective agreement with the Power Workers' Union ("PWU") and entered into early negotiations for a new three-year collective agreement with the Society of Energy Professionals ("the Society") as discussed in Exhibit C1, Tab 4, Schedule 1. The first negotiated wage increase for the new Society collective agreement was a 0.5% base salary adjustment on April 1, 2016.

Hydro One filed this two-year (2017-2018) Transmission Cost of Service application on May 31, 2016. The Company intends to file a five-year Custom IR Distribution rate application (for 2018 to 2022) in the first quarter of 2017 and an RRFE-compliant, multi-year transmission rate application in early 2018. The timing of current application did not allow for a quality Total Compensation Study to be completed for this rate application; the study would not have adequately captured the total effects of the new collective agreements.

Hydro One does plan to complete an updated Total Compensation Study and to submit this study in conjunction with its application for 2018 to 2022 Distribution rates, consistent with the direction of the OEB in its Decision in proceeding EB-2013-0416, dated March 12, 2015.

Hydro One does not have similar compensation data relevant to its peers for this application. However, since the last study in 2013, Hydro One has continued to reduce compensation costs in all of the employee categories by

- closing the MCP Defined Benefit Pension Plan to new entrants and introducing a new Defined Contribution Pension Plan;
- increasing employee pension contributions and making progress toward a 50-50 contribution rate between Hydro One and employees; and

- negotiating lower than normal base wage increases for represented employees in the last rounds of collective bargaining.

Ontario Energy Board (Board Staff) INTERROGATORY #131

Reference:

Exhibit C1/Tab 4/Sch2, p. 2 – Table 1 Cash Pension Cost

Interrogatory:

a) Please reconcile the total cash pension cost for the test years to the annual funding requirements outlined in the June 9, 2016 Willis Towers Watson actuarial valuation provided in Exhibit C1/Tab 4/Sch 2, Attachment 1 (p.19).

b) Hydro One Transmission has historically recovered OPEBs in rates on an accrual basis:

i) Please complete the table below to illustrate the delta between recovering on an accrual basis compared to the actual cash benefit payments made in the given years.

ii) Please describe what Hydro One Transmission has done with any recoveries in excess of cash benefit payments.

iii) How are OPEB costs allocated between the Transmission and Distribution operations?

iv) How are OPEB costs allocated between OM&A and Capital?

v) Please provide the actuarial valuation to support the amounts being claimed in the test years as noted in above graph.

Response:

a)

	2017	2018
Normal actuarial cost	79,932	77,446
Going concern payments	9,119	9,119
Solvency amortization payments	15,586	15,586
Updated total cash pension cost	104,637	102,151

Subsequent to the filing of the blue page update, Hydro One completed a detailed reconciliation of the various components of the Pension costs and compared to the interim valuation information. As a result, it is updating the Pension cost information for the test years resulting in a further decrease to the plan's operating expenses. The update is outlined below:

2017 - Forecast					
Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	18	26	4	48
Capital	$M	31	25		57
	$M	**49**	**52**	**4**	**105**
2018 - Forecast					
Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	16	24	4	44
Capital	$M	30	28		58
	$M	**46**	**52**	**4**	**102**

In test years 2017 and 2018, OM&A is reduced by $0.4M and $1.9M, respectively, relative to the filed Blue Page update.

b)

i.

OPEBs	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Amounts included in rates:						
OM&A	25	28	23	20	23	21
Capital	28	29	28	23	29	30
Sub-total	**53**	**57**	**51**	**44**	**52**	**50**
Paid benefit amounts	19	20	20	23	24	26
Net excess amount included in rates greater than amounts actually paid	34	37	31	21	27	25

ii. Recoveries in excess of cash benefit payments form part of Hydro One's working capital, which is invested in capital and OM&A work programs.

iii. OPEB costs are allocated between Transmission and Distribution as well as between OM&A and capital based on the work programs of the Transmission and Distribution businesses which includes the allocation between the type of work involved (capital vs OM&A).

iv. See response to (iii) above.

v. Hydro One does not have an actuarial valuation for OPEB expense. However Hydro One does have a projected cost report from Willis Towers Watson and has summarized the costs in the table below:

	2017	2018
Expected Benefit Cost	95,079	96,635
Expected Benefit Cost	6,489	6,373
Expected Benefit Cost	8,040	8,189
	109,608	111,197

Please note the portion of consolidated expense allocated to Transmission OM&A and Capital are noted below for 2017 and 2018.

2017	2018
21% OM&A	19% OMA
27% Capital	27% Capital

The relevant tables from the report supporting the costs above have been provided in the tables below.

Figures in $000s	Projections 2017	Projections 2018
Components of Benefit Cost		
Employer service cost	32,583	32,516
Interest cost	61,109	63,150
Expected return on plan assets	-	-
Net prior service (credit)/cost amortization	-	-
Net (gains)/loss amortization	1,387	969
Curtailments	-	-
Settlements	-	-
Special/contractual termination benefits	-	-
Disclosed benefit cost	95,079	96,635

Components of Benefit cost		
Employer service cost	1,352	1,242
Expected letter of credit fee	390	390
Interest cost	4,231	4,307
Expected return on plan assets	0	0
Net prior service cost amortization	10	0
Net loss/(gain) amortization	506	434
Curtailments	0	0
Settlements	0	0
Special/contractual termination benefits	0	0
Net expense (income)	6,489	6,373

1

Components of Benefit Cost		
Employer service cost	5,776	5,905
Interest cost	2,264	2,284
Expected return on plan assets	-	-
Net prior service (credit)/cost amortization	-	-
Net (gains)/loss amortization	-	-
Curtailments	-	-
Settlements	-	-
Special/contractual termination benefits	-	-
Disclosed benefit cost	8,040	8,189

2

Ontario Energy Board (Board Staff) INTERROGATORY #132

Reference:

Exhibit C1/Tab 4/Sch2, p. 4

Interrogatory:

Please provide more detailed information on the Pension Funds target benchmark. What is this benchmark comprised of and why is it an appropriate benchmark for the Pension Plan?

Response:

The Fund's target asset mix is determined by conducting an extensive asset liability study. The asset liability study provides a detailed analysis of scenarios that best achieves the long-term objectives of the pension and investment strategy. The Fund's target asset mix is best measured using a target benchmark. The Fund's investment performance is measured against a range of objectives consistent with the pension and investment strategy as well as benchmarks for the respective underlying asset classes of the target asset mix ("target benchmark"). The target benchmark provides an effective way to evaluate and measure the Fund's implementation of the target asset mix. The benchmarks used by the Fund are industry accepted benchmarks.

Below are the asset classes in which the Fund is invested and the respective underlying benchmarks used to measure the performance of each asset class. A strategic asset allocation (target asset mix) is made to each asset class (target benchmark).

Asset Class	Benchmark	Strategic Asset Allocation as at December 31, 2015
Canadian Equity	S&P TSX Composite Index	12.0%
U.S. Equity	S&P 500 Total Return Index	12.0%
International Equity	MSCI EAFE Net Dividend Index	12.0%
Global Equity	MSCI World Net Dividend Index	14.0%
Private Equity	S&P 500 Total Return Index	5.0%
Real Estate	FTSE NAREIT Developed Index	5.0%
Infrastructure	FTSE Global Infrastructure 50/50 Index	5.0%
Universe Bonds	FTSE TMX Canada Universe Bond Index	18.0%
Long Bonds	FTSE TMX Canada Long Bond Index	15.0%
Cash & Cash Equivalents	FTSE TMX 91-day T-bill index	2.0%
Total Fund - Target Asset Mix	Weighted average of the above individual asset classes – Target Benchmark	100%

When choosing the appropriate benchmark for each of the asset classes in the Fund several factors were taken into consideration, namely:

- The benchmark had to be investable (in the case of publicly listed equities and bonds);
- The benchmark had to be generally accepted and recognized within the investment industry (i.e., how widely a specific benchmark is used by market participants);
- The benchmark represented the types of exposures that the Fund was looking for within an asset class;
- Historical data was readily available for the benchmark; and
- The benchmark was purposeful (i.e., the asset class included in the portfolio has a specific purpose, and then the chosen benchmark should accomplish that purpose).

At the total or aggregate level, the Fund's benchmark is determined by way of using a weighted-average of the individual asset class benchmarks, with the weightings based on the target allocations for each asset class. Hydro One's view is that including a portfolio benchmark comprised of the individual asset class benchmarks allows for an additional layer of performance attribution when analyzing performance results.

The Fund has selected the benchmarks that allow for the appropriate measurement of the Fund's investment performance. The target benchmark is appropriate as it provides an effective means to measure the implementation of the Fund's target asset mix.

Ontario Energy Board (Board Staff) INTERROGATORY #133

Reference:

Exhibit C1/Tab 5/Sch1, p. 13

Interrogatory:

Hydro One indicates that its equipment utilization averages have increased from 65% in 2001 to 81% in 2015.

Will Hydro One continue to be able to increase utilization rates in 2016, 2017 and 2018? Does Hydro One have a target for equipment utilization? What is a comparable industry standard rate?

Response:

Hydro One plans to increase the equipment utilization rate by installing telematics on more fleet vehicles and equipment, as described in Exhibit C1, Tab 5, Schedule 1. This will allow Hydro One to take advantage of real-time data from cellular and satellite modems to increase fleet utilization and "right-size" Hydro One's fleet levels. Management intends to consider targets once the telematics project is completed.

No comparable industry standard equipment utilization rate is available at this time. Hydro One is monitoring its usage statistics year-over-year.

Ontario Energy Board (Board Staff) INTERROGATORY #134

Reference:
Exhibit C1/Tab 8/Sch1 – Departure from PILs Regime

Interrogatory:
Hydro One Limited realized a deferred tax recovery of $2,619 million that was triggered by the deemed disposition of its assets upon exiting the PILs regime in 2015 (see page 28 of the Hydro One Limited 2015 Annual Report). The impact of this deferred tax recovery has been excluded from the test year PILs calculations filed with this application.

a) In RP-2004-0188, Report of the Board on the 2006 Electricity Distribution Rate Handbook, the OEB reviewed a similar matter related to a deferred tax recovery that utilities realized upon first entering the PILs regime in 2001 (RP-2004-0188, pp. 55-57). Given the similar circumstances, has this conclusion been considered in determining the regulatory treatment of the $2,619 million deferred tax recovery in the current application?

b) What portion, if any, of the $2,619 million deferred tax recovery would be allocated to the Transmission business?

c) How would the test period PILs calculations in Exhibit C2/Tab 4/Sch 1, Attachment 1 be impacted if the deferred tax recovery was applied to the estimate?

Response:
a) Consideration of the Board's RP-2004-0188 Report, including the sections on pp.55-57, was given in the preparation of this application. The present circumstances however differ significantly from the Fair Market Value Bump scenario discussed in the Board's Report. Specifically:

- The IPO process resulted in a change in Hydro One's relevant taxation regime and triggered a deemed disposition of assets for taxation purposes. The loss of Hydro One's exemption from tax under the existing legislative scheme and its departure from the PILs regime cannot be reasonably described as a change in tax rules that would fall into the category of a taxation change subject to true-up in rates;

- In the RP-2004-0188 Report, the OEB disregarded the regulatory principle that "benefits follow costs" and determined that ratepayers should benefit from the deferred tax recovery on the basis that shareholders would not be disadvantaged as they had not incurred a cost as a result of the Fair Market Value Bump. However, that is not the case here. The IPO process triggered the above-mentioned change in taxation regime, the Fair Market Value Bump, the associated requirement for Hydro One Limited to pay the departure tax of $2.6 billion and the requirement for Hydro One Limited to recognize the deferred tax recovery. The amount of the departure tax was driven substantially by the Fair Market Value of the assets. As a result, Hydro One Limited incurred a real $2.6 billion cost associated with the Fair Market Value Bump and would be disadvantaged if it is not allocated 100% of the benefit of the deferred tax recovery;

- The incurrence of the departure tax and the recognition of the deferred tax recovery arise from facts and circumstances that do not relate to Hydro One's rate regulated activities. These amounts arise from the IPO process. This process is not a rate regulated activity and the resulting Fair Market Value Bump does not affect the accounts and balances upon which rates are set. The OEB acknowledged in the 2006 DRH that under the "stand-alone" principle, the Fair Market Value Bump should be disregarded, such that in the current circumstances, Hydro One Limited and its shareholders would be solely responsible for the costs and benefits from changes arising from the Fair Market Value Bump; and

- Hydro One incurred a real cost. The payment of the departure tax by Hydro One Limited and how it was funded by Hydro One Limited's shareholder is set out in the financial statements filed as part of the evidentiary basis for this application. Payment by Hydro One Limited of the departure tax reduced its retained earnings by approximately $2.6 billion. In order to mitigate the potentially negative financial consequences arising from the payment of the departure tax, Hydro One Limited's shareholder funded the payment by purchasing a corresponding number of common shares of the company. The purchase of common shares restored the common equity component of Hydro One Limited's capitalization and maintained the strong financial profile of the company.

b) $1,475 million of the $2,619 million deferred tax recovery pertains to the transmission business.

c) The requested analysis has not been performed as it would be inconsistent with the "stand-alone" and "benefits follow costs" principles used in the Board's RP-2004-0188 Report, and the Board's Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016, and the OEB's related predecessor policies[1].

[1] EB-2014-0138 Report of the Board regarding Rate-Making Associated with Distributor Consolidation dated March 26, 2015, Report of the Board regarding Rate-making Associated with Distributor Consolidation dated July 23, 2007 and the determinations of the Board in the Combined Proceeding Decision – OEB File No. RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

Ontario Energy Board (Board Staff) INTERROGATORY #135

Reference:

Exhibit C2/Tab 4/Sch1 Attachment 1 – Calculation of Utility Income Taxes

Interrogatory:

The OEB approved PILs Model requires that a utility's return on deemed equity be used as the starting point (i.e. Net Income Before Tax) when computing Regulatory Taxable Income for the test year.

a) What value is being presented as the "Regulatory Net Income (before tax)" in the test year calculations for PILs?

b) Why hasn't the test year return on deemed equity, as calculated in Table 1 of Exhibit D1/Tab 4/Sch 1, been used as the Regulatory Net Income (before tax)?

c) How would the test year PILs calculations be impacted had the return on deemed equity been used as the starting point?

Response:

a) The value presented as the "Regulatory Net Income (before tax)" in the test year calculations for utility income tax was based on the return on deemed equity presented in Hydro One's current application.

	2017	**2018**	**Evidentiary Reference**
Return on common equity	$388.0	$412.6	D1-4-1, page 4
Utility income tax	81.3	90.4	C2-4-1, Attachment 1
Regulatory Net Income (before tax)	$469.3	$503.0	

b) Please see response in a) above.

c) There is no impact to the test year utility income tax calculations as the return on deemed equity was used as the starting point as noted in a) above.

Witness: Giovanna Baragetti

Ontario Energy Board (Board Staff) INTERROGATORY #136

Reference:

Exhibit C2/Tab 4/Sch1 Attachment 1 – Calculation of Utility Income Taxes

Interrogatory:

Based on the PILs calculations provided for historical years in Exhibit C2/Tab4/Sch 1, Attachment 3, it appears that interest capitalized for accounting purposes, but deductible for tax purposes, has typically been approximately $32-35 million per year. An estimate for this deduction does not appear to be incorporated within the test year PILs calculation, please explain why. If this is an oversight, please update the test year calculation to incorporate the impact of this item.

Response:

For tax return purposes, the net income before tax is the starting point in determining taxable income for the historical years reflected in Exhibit C2, Tab 4, Schedule 1, Attachment 3. This net income computation only reflects a portion of the interest deductible for tax purposes. As such, a deduction is made to reflect the interest capitalized for accounting purposes.

However, when computing *regulatory taxable income* for the test year utility income tax calculation (provided in Exhibit C2, Tab 4, Schedule 1), the starting point is the net income before tax computed in accordance with the OEB-approved model, which requires that a utility's return on deemed equity be used without any consideration of capitalized interest. (Please see Exhibit I, Tab 1, Schedule 135). Since the regulatory net income before tax used in determining taxable income for the test year does not reflect any interest expense, an adjustment similar to that reflected for the historical years is not required for interest capitalized for accounting purposes.

Witness: Giovanna Baragetti

Ontario Energy Board (Board Staff) INTERROGATORY #137

Reference:
Exhibit C2/Tab 4/Sch1 Attachment 1 – Calculation of Utility Income Taxes

Interrogatory:
How does the deduction for Capitalized Pension Costs in the test year PILs calculations reconcile to the capitalized pension cost amounts presented in Table 1 of Exhibit C1/Tab 4/Sch 2?

Response:
Please refer to Attachment 1 of Exhibit C2, Tab 4, Schedule 1, which reflects deductions for capitalized pension costs of $50.5 million and $48.6 million in the income tax calculations for 2017 and 2018, respectively. These amounts agree with the capitalized pension cost amounts originally filed in Exhibit C1, Tab 4, Schedule 2 on May 31, 2016.

On July 20, 2016, Hydro One filed a blue page update to its current application, which reflected lower capitalized pension costs of $33 million and $32 million for 2017 and 2018, respectively, as presented in Table 1 of Exhibit C1, Tab 4, Schedule 2. The original test year income tax calculations shown in Exhibit C2, Tab 4, Schedule 1, Attachment 1 were not updated. This means that the income tax cost reflected in revenue requirement is lower than it would have been if the updated pension costs were used in its calculation. Subsequent to the blue page update, the cash pension costs were updated, as described in response (a) in Exhibit I, Tab 1, Schedule 131. The revised capitalized components are $31 million and $30 million for 2017 and 2018, respectively. Taking into account the new cash pension costs noted above and properly reflecting the capitalization component in the calculation of utility income tax, as the well as the impact of the tax return update as described in Exhibit I, Tab 1, Schedule 138, please see below for a revised calculation of utility income taxes.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Utility Income Taxes
Test Years (2017 and 2018)
Year Ending December 31
($ Millions)

Line No.	Particulars		2017		2018	
			(a)		(b)	
	Determination of Taxable Income					
1	Regulatory Net Income (before tax)	$	477.0	$	509.6	
2	Book to Tax Adjustments:					
3	Other Post Employment Benefits expense		22.5		20.7	
4	Other Post Employment Benefits payments		(26.1)		(26.5)	
5	Inergi pension payments		0.0		0.0	
6	Depreciation and amortization		435.7		470.7	
7	Capital Cost Allowance		(513.1)		(545.8)	
8	Removal costs		(2.1)		(2.1)	
9	Environmental costs		(11.6)		(10.0)	
10	Hedge loss – amortization		0.2		0.2	
11	Non-deductible meals & entertainment		3.6		3.6	
12	Capital amounts expensed under $2K		3.5		3.5	
13	Research & Development ITC		0.5		0.5	
14	Ontario education credits		0.3		0.3	
15	Capitalized overhead costs		(34.2)		(34.6)	
16	Capitalized pension costs		(31.0)		(29.7)	
17	Debt Issuance costs – amortization		1.8		1.8	
18	Debt Issuance costs - 21e deduction		(2.5)		(2.8)	
19	Premium/Discount – amortization		(0.8)		(0.3)	
20	Bond discount deduction		0.0		0.0	
21	Capital Contribution True-Up Adjustment		11.7		7.2	
22	Other		3.6		2.7	
23		$	(138.0)	$	(140.6)	
24	Regulatory Taxable Income	$	339.0	$	369.1	
25	Corporate Income Tax Rate		26.50	%	26.50	%
26	Subtotal	$	89.8	$	97.8	
27	Less: R&D ITC / Ontario education credits		(0.8)		(0.8)	
28	Regulatory Income Tax	$	89.0	$	97.0	

	<u>Tax Rates</u>				
29	Federal Tax	15.00	%	15.00	%
30	Provincial Tax	11.50	%	11.50	%
31	Total Tax Rate	26.50	%	26.50	%

Ontario Energy Board (Board Staff) INTERROGATORY #138

Reference:

Exhibit C1/Tab 8/Sch1 Attachment 1 – Integrity Checks

Interrogatory:

This section indicates that the December 31, 2015 federal T2 tax return was not prepared at the time of this application and therefore estimated December 31, 2015 UCC balances were used in preparing the UCC/CCA continuity for the bridge year (opening balances).

a) Please provide a copy of December 31, 2015 federal T2 tax return that was filed as of June 30, 2016.

b) Please update the UCC/CCA continuity schedules for the bridge and test years in Exhibit C2/Tab 4/Sch 1, Attachment 2 based on the actual Schedule 8 UCC balances filed in the December 31, 2015 tax return.

c) Has there been any correspondence from the related tax authorities since filing the December 31, 2015 T2 return that impact the UCC/CCA balances presented in Schedule 8? If so, please ensure that these are factored into the updated numbers provided in (b) above.

Response:

a) Please see Attachment 3 to Exhibit C2, Tab 5, Schedule 1, which was filed with the OEB on August 10, 2016.

b) Please see Attachment 1 to this response. Also embedded in the results of Attachment 1 is the inclusion of the UCC and CCA impacts of the cash pension reductions. This update has been incorporated into the changes requested in part b) of this question. Please refer to Exhibit I, Tab 1, Schedule 131 for an explanation of the cash pension changes and Exhibit I, Tab 1, Schedule 137 for the Schedule 1 adjustments associated with the cash pension changes.

c) There has been no such correspondence.

UPDATE TO CALCULATION OF CAPITAL COST ALLOWANCE – BRIDGE (2016) TEST (2017, 2018) YEARS

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2016 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2016 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,015.4	35.2	2,050.6	17.6	2,033.0	4%	81.3	1,969.3
2	535.7	-	535.7	-	535.7	6%	32.1	503.6
3	239.7	-	239.7	-	239.7	5%	12.0	227.7
6	70.54	-	70.4	-	70.4	10%	7.0	63.4
7	-	-	0.0	-	0.0	15%	0.0	0.0
8	121.5	48.2	169.7	24.1	145.6	20%	29.1	140.6
9	2.2	-	2.2	-	2.2	25%	0.5	1.6
10	46.4	16.2	62.5	8.1	54.5	30%	16.3	46.1
12	3.3	9.6	12.8	4.8	8.2	100%	8.2	4.7
13	15.5	(0.6)	14.9	-	15.5	N/A	0.9	14.0
17	71.3	3.3	74.6	1.7	73.0	8%	5.8	68.7
35	0.1	-	0.1	-	0.1	7%	0.0	0.1
42	73.6	-	73.6	-	73.7	12%	8.8	64.8
45	0.1	-	0.1	-	0.1	45%	0.0	0.1
46	9.5	-	9.5	-	9.5	30%	2.9	6.7
47	2,946.3	539.6	3,485.9	269.8	3,216.1	8%	257.3	3,228.6
50	76.3	13.3	89.6	6.6	82.9	55%	45.6	44.0
52	-	0.1	0.1	-	0.1	100%	0.1	-
Total CCA	**6,227.3**	**664.7**	**6891.9**	**332.6**	**6560.2**		**508.1**	**6383.9**
						Less CCA not in rates	(9.5)	
CEC	46.6	5.5	52.1	2.7	49.3	7%	3.5	48.6
						Total CCA for RR	**502.1**	

Witness: Giovanna Baragetti

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2017 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2017 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,969.3	33.4	2,002.7	16.7	1,986.0	4%	79.4	1,923.3
2	503.5	0.0	503.5	-	503.5	6%	30.2	473.3
3	227.7	0.0	227.7	-	227.7	5%	11.4	216.4
6	63.4	0.0	63.4	-	63.4	10%	6.3	57.1
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	140.6	17.8	158.4	8.9	149.5	20%	29.9	128.5
9	1.6	0.0	1.6	-	1.6	25%	0.4	1.2
10	46.1	16.3	62.4	8.1	54.2	30%	16.3	46.2
12	4.7	17.3	21.9	8.6	13.2	100%	13.2	8.7
13	14.0	(0.8)	13.2	-	14.0	N/A	0.9	12.3
17	68.7	1.1	69.9	0.5	69.3	8%	5.5	64.3
35	0.1	0.0	0.1	-	0.1	0.07	0.0	0.1
42	64.8	0.0	64.8	-	64.8	0.12	7.8	57.0
45	0.1	0.0	0.1	-	0.1	45%	0.0	0.0
46	6.7	0.0	6.7	-	6.7	30%	2.0	4.7
47	3,228.6	678.1	3,906.7	339.1	3,567.7	8%	285.4	3,621.3
50	44.0	21.6	65.6	10.8	54.8	55%	30.1	35.5
52	-	0.1	0.1	-	0.1	100%	0.1	(0.0)
Total CCA	**6,383.9**	**785.0**	**7,168.9**	**392.7**	**6,776.7**		**519.0**	**6,649.8**
						Less CCA not in rates	(9.5)	
CEC	48.6	6.6	55.2	3.3	51.9	7%	3.6	51.6
						Total CCA for RR	**513.1**	

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2018 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2018 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,923.3	37.4	1,960.7	18.7	1,942.0	4%	77.7	1,883.0
2	473.3	0.0	473.3	-	473.3	6%	28.4	444.9
3	216.4	0.0	216.4	-	216.4	5%	10.8	205.5
6	57.1	0.0	57.1	-	57.1	10%	5.7	51.4
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	128.5	43.3	171.9	21.7	150.2	20%	30.0	141.8
9	1.2	0.0	1.2	-	1.2	25%	0.3	0.9
10	46.2	18.6	64.8	9.3	55.4	30%	16.6	48.2
12	8.7	10.9	19.7	5.5	14.2	100%	14.2	5.5
13	12.3	(0.2)	12.1	(0.1)	12.2	N/A	0.8	11.3
17	64.3	3.9	68.2	1.9	66.3	8%	5.3	62.9
35	0.1	0.0	0.1	-	0.1	7%	0.0	0.1
42	57.0	0.0	57.0	-	57.0	12%	6.8	50.1
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	4.7	0.0	4.7	-	4.7	30%	1.4	3.3
47	3,621.3	967.4	4,588.7	483.8	4,105.1	8%	328.4	4,260.3
50	35.5	15.2	50.7	7.6	43.1	55%	23.7	26.9
52	-	0.1	0.1	0.0	0.1	100%	0.1	-
Total CCA	**6,6649.8**	**1,096.7**	**7,746.5**	**548.4**	**7,198.2**		**550.3**	**7,196.2**
						Less CCA not in rates	(8.7)	
CEC	51.6	14.9	66.5	7.4	59.0	7%	4.1	62.4
						Total CCA for RR	**545.8**	

Witness: Giovanna Baragetti

Ontario Energy Board (Board Staff) INTERROGATORY #139

Reference:
Ref: Exhibit C1/Tab 8/Sch1 Attachment 1 – Integrity Checks

Interrogatory:
A statement is made that "The 2015 CCA deductions in the PILs tax model do not agree with the numbers in the UCC schedules because Hydro One received a significant amount (approximately $55 million) of capital contribution true-ups from customers. These amounts are treated as taxable income by the tax authorities rather than reduction of UCC balances for 2015 tax purposes".

Currently the CCA deductions used in the PILs model filed in Exhibit C2/Tab 4/Sch 1, Attachment 1 and Attachment 3 agree to the detailed CCA calculations provided in Exhibit C2/Tab 4/Schedule 1, Attachment 2 and Attachment 4.
Please explain what this statement is referring to.

Response:
The CCA deductions used in the Utility Income Tax model filed in Attachments 1 and 3 to Exhibit C2, Tab 4, Schedule 1 agree with the detailed CCA calculations provided in Attachments 2 and 4 to the same Exhibit. The reconciliation provided at the bottom of the CCA schedules indicates the amount of CCA available for revenue requirement purposes after the total CCA is reduced by a "non-regulatory" CCA amount. The "non-regulatory" CCA primarily pertains to the capital contribution true-ups not included in the revenue requirement.

Ontario Energy Board (Board Staff) INTERROGATORY #140

Reference:

Exhibit C1/Tab 3/Sch7 – Section 2.1 Transmission Stations and Buildings

Interrogatory:

This section states that a province wide reassessment was due to take place in 2016 by MPAC to refresh property values for property tax calculation purposes. Has this reassessment been received and how does it impact the values shown in Table 2?

Response:

As of the date of this response, Hydro One has not received any notices of the province-wide re-assessment.

Ontario Energy Board (Board Staff) INTERROGATORY #141

Reference:

Exhibit D/Tab1/Sch4

Interrogatory:

The evidence shows that Working Capital increases in 2017 to $14.7 million, an increase of over 70% from the 2016 level, with a subsequent increase of 6% in 2018.

Please provide an itemized list of the primary factors that contribute to the increase in working capital from 2016 to 2017 and from 2017 to 2018.

Response:

The primary factor of this increase is due to the inclusion of a significant pre-payment of utility income tax in the first half of the year which was not captured in the prior study. The pre-payment of utility income tax are based on predictions of net income in which it was deemed; and in the current study, the pre-payment accurately reflects the timing of the utility income tax payment.

The 2018 increase over 2017 is due to higher interest expenses which are as a result of the increased long term debt being borrowed in 2018.

Ontario Energy Board (Board Staff) INTERROGATORY #142

Reference:

Exhibit E1/Tab 2/Sch1, p. 2

Interrogatory:

Table 1 shows that External Revenues fall significantly from 2015 to 2016 in all 3 major categories of external revenues.

a) Regarding Secondary Land Use, Hydro One cites previously high levels of unbudgeted transactions involving easement grants and land sales. What is the reason for the precipitous drop in these revenues in 2016, 2017 and 2018?

b) For Station Maintenance, Hydro One cites a lower volume of work from major customers. Why is there a lower volume of work for this revenue source?

c) For Other External Revenues, why do levels fall from 2016 to 2018?

Response:

a) The unbudgeted, historical transactions referred to were one-time sales and easement transactions for major projects, including pipeline projects in the Greater Toronto Area and storm water management ponds (“SWMP”) in the Waterloo Region. There are no large pipeline projects or SWMP projects expected in the bridge or test years, which explains the drop in forecast revenues for 2016, 2017, and 2018. Hydro One also expects a decrease in municipal and regional road transactions in the later years.

b) The lower volume of work is due to a drop in the maintenance work on OPG’s Pickering and Darlington stations. In addition, maintenance work for Bruce Power began decreasing in 2015 and is expected to continue its downward trend.

c) Other External Revenues in 2016 to 2018 are lower than the 2015 figure because the 2015 figure reflects high Infrastructure Ontario payments related to the one-time sales and easement transactions discussed in part a) above.

Witness: Glenn Scott

Ontario Energy Board (Board Staff) INTERROGATORY #143

Reference:
Exhibit E1/Tab 3/Sch. 1, pp. 3–8

Interrogatory:
In section 3 of Exhibit E1/Tab 3/Sch. 1, Hydro One summarizes some of the key economic assumptions that influence its load forecasts.

a) Please provide the source(s) of the economic data that is provided in section 3 of Exhibit E1/Tab 3/Sch. 1.

b) If any of the forecast economic assumptions are calculated by Hydro One, please explain the methodology used to forecast those quantities.

Response:
a) The sources of economic data used in Section 3 of the above-noted Exhibit, as well as the methodology used to forecast these quantities, are listed below.
   i. Ontario GDP: Please see page 26, lines 17-21 of the above-noted Exhibit.
   ii. Ontario population: The historical data is from Statistics Canada. The forecast data is based on the average of population forecasts from IHS Global Insight and C4SE.
   iii. Housing Forecast: The historical data is from IHS Global Insight. The forecast data is based on Consensus Forecast presented in Appendix E (second table) of the above-noted Exhibit.
   iv. Commercial floor space: The historical data is from IHS Global Insight. Using econometric analysis, the forecast data is internally derived from variables for which forecasts were available including:
      - Ontario population as defined above;
      - Ontario real disposable income (page 30, lines 17-22 of above-noted Exhibit); and
      - Ontario GDP as defined above.
   v. Industrial production: Both historical and forecast values are from IHS Global Insight. The forecast values were scaled to be consistent with consensus forecast as defined in Appendix E (first table) of the above-noted Exhibit. The scale factor used is defined as the ratio of GDP forecast based on consensus forecast growth rates divided by the IHS Global Insight GDP forecast.

b) Where applicable, the methodology is described in a) above.

Witness: Bijan Alagheband

Ontario Energy Board (Board Staff) INTERROGATORY #144

Reference:

Exhibit E1/Tab 3/Sch. 1, pg. 50

Interrogatory:

In Appendix G, Hydro One states that its comparison of load forecast results with the IESO is "consistent with the latest Hydro One consultation with IESO in February 2016."

Please summarize the activities/consultations Hydro One undertakes with the IESO to ensure consistency between the results of the IESO's 18-month forecast and Hydro One's forecast of transmission charge determinants.

Response:

Hydro One consulted with the IESO on the items noted below in order to ensure consistency between the two forecasts.

1. Assumptions for CDM and Embedded Generation
   a. CDM: IESO provided the historical and forecast values for CDM and well as their hourly profile by program. Hydro One used the information provided by IESO to calculate CDM by program in each month.

   b. Embedded Generation ("EG"): IESO provided an EG energy forecast up to December 2018 as well as an EG peak forecast up to June 2017. Hydro One used IESO's energy-to-peak ratio (i.e., load factor) and energy monthly profile to estimate EG monthly peak values up to December 2018.

2. Models
   The IESO uses an econometric model to forecast Ontario's peak for the next 18 months and does not have a forecast of charge determinants. Hydro One uses a variety of econometric and end-use models to forecast both monthly peak and charge determinants that are consistent with monthly peak.

3. Results
   The IESO assumes that extreme weather occurs on the busiest day (Wednesday) for system reliability purposes. In practice, extreme weather may happen on any day of the week. For this reason, Hydro One does not assume that extreme weather occurs on Wednesdays.

Accordingly, Hydro One’s average peak forecast over the forecast horizon is lower compared to that of the IESO, as detailed in Appendix G of the above-noted Exhibit. Another definitional difference discussed in Appendix G relates to the treatment of demand response (“DR”). IESO adds DR to the Ontario peak forecast and considers DR as a source of supply in balancing demand and supply. Hydro One needs to consider demand net of DR to account for the loss in demand and revenue caused by DR. If Hydro One used the IESO’s treatment of DR, its load forecast would be artificially higher. Accordingly, it is appropriate to use the net forecast value for the purposes of determining charge determinants.

Ontario Energy Board (Board Staff) INTERROGATORY #145

Reference:

Exhibit F1/Tab 1/Sch2 – Regulatory Accounts Requested: Section 2.6

Interrogatory:

Section 2.6 is proposing to continue to use this account to record the difference between the actual pension cost based on the May 2012 Towers Willis Watson actuarial valuation and what will be approved by the Board as part of the 2017 and 2018 Transmission Rates.

Shouldn't the May 2012 report referenced in this section be replaced with the latest valuation from Towers Willis Watson received on June 9, 2016? Please explain.

Response:

Subsequent to the filing of the updated valuation with the Financial Services Commission of Ontario and the blue page update, Exhibit F1/Tab 1/Sch2 section 2.6 is updated as follows:

"This account is a continuation of the account accepted in EB-2012-0031. Hydro One Transmission proposes to continue to record the difference between the actual pension costs booked using the actuarial valuation provided by Willis Towers Watson and filed with the Financial Services Commission of Ontario in June 2016, and the estimated pension costs approved by the Board as part of 2017 and 2018 Transmission Rates."

Ontario Energy Board (Board Staff) INTERROGATORY #146

Reference:

Exhibit F1

Interrogatory:

Certain filing information does not appear to be present in this section of the Application (Exhibit F1), including the following:

a) Section 2.10 of the Chapter 2 Filing Requirements states that the applicant must provide the interest rates used to calculate the carrying charges by month or by quarter for each year. Please provide.

b) Section 2.10 also requires that the applicant makes a statement as to whether adjustments had been made to deferral and variance account balances that were previously approved by the OEB on a final basis. Please provide accordingly.

Response:

a) The interest rate used to calculate the carrying charges for 2016 was 0.96% and was determined using the OEB's methodology (the Bankers' Acceptances-3 month plus 0.25 Spread). Hydro One applied the Bankers' Acceptances-3 month issued by the Board on October 15, 2015 (Re: Cost of Capital Parameter Updates for 2016 Applications), i.e., 0.712%. Any difference in this rate (0.96%) and actual OEB prescribed rate would remain in the deferral account for disposition in a future application.

b) Exhibit F1, Tab1, Schedule 1, section 2.1 – section 2.9 notes in the description of each account where an adjustment has been made to account balances to reflect disposition amounts previously approved by the OEB.

Ontario Energy Board (Board Staff) INTERROGATORY #147

Reference:

Exhibit G/Tab 1/Sch1

Interrogatory:

Hydro One is proposing to simplify the allocation process by eliminating the Wholesale Meter rate pool and allocating the related revenue requirement into the three remaining rate pools.

Please provide the Wholesale Meter rate pool revenue requirement amounts each year from 2012 to 2016 and the forecast amounts for 2017 and 2018.

Response:

The Wholesale Meter rate pool revenue requirement amounts for each year from 2012 to 2016 and the forecast amounts for 2017 and 2018 are provided in the table below.

Case Number	**Effective Year**	**Wholesale Meter Rate Pool Revenue Requirement ($M)**
EB-2011-0268	2012	0.6
EB-2012-0031	2013	0.9
EB-2012-0031	2014	0.7
EB-2014-0140	2015	0.3
EB-2014-0140	2016	0.2
EB-2016-0160	2017	0.3*
EB-2016-0160	2018	0.3*

* *Implied revenue requirement based on proposed Wholesale Meter Services fee*