G-SEC-1

Reference(s): Ex. 1/1/1, p. 3, 20

Please provide details of all of the steps taken to make sure the Board had the Application in sufficient time to consider the evidence and approve rates, after an appropriate hearing, in time for January 1, 2018 implementation. Please provide a representative timeline of regulatory steps to demonstrate that the Application was timely.

Response:

Alectra Utilities filed its application for electricity distribution rates effective January 1, 2018. In filing, Alectra Utilities considered the nature of the application and the Ontario Energy Board's ("OEB") performance guidelines for the adjudication of applications.

The application was filed on July 7, 2017. A considerable portion of the application pertains to mechanistic adjustments to EDR. Alectra Utilities' expectation was for a streamlined hearing. Alectra Utilities specifically asked for a written hearing. The performance standard posted by the OEB is 140 days for the adjudication of such an application. Based on the filing date, there were 177 days available to dispose of the application in 2017. Should the application follow a standard written hearing, the posted performance standard would be 185 days. While this would carry over into 2018 (mid January), it would still be possible for Alectra Utilities to implement rates for January 1, 2018. Alectra Utilities anticipated that this would be the case even if a portion of the application were heard orally.

Once the application is filed, applicants are in the OEB's hands in terms of the issuance of the Notice of Application and setting of procedural steps.

G-SEC-2

Reference(s): Ex. 1/1/1, p. 4, 5 and 2/4/11, p. 2

Please provide a detailed analysis of the ways, if any, that the Enersource RZ DSP reflects a different asset management and distribution system management approach relative to the DSPs already reviewed by the Board for the Brampton RZ, the Horizon RZ and the Powerstream RZ.

Response:

In each Alectra Utilities rate zone, asset and distribution system management practices are suited to the specific needs and requirements of each service area. The framework, objectives and direction of asset management practices were developed to be aligned with legacy corporate objectives and strategies while recognizing the configuration and condition of distribution system assets, service area attributes and numerous internal and external drivers. To minimize rate impacts, all asset management practices at Alectra Utilities addresses competing investment needs through pacing and investment prioritization. Such investment requirements vary by rate zone and require adjusted asset management approaches to address unique service area needs.

The City of Mississauga is now in a post-greenfield phase. Growth is projected to continue with ongoing intensification and redevelopment, especially in the downtown core and certain business districts. Much of Mississauga's growth occurred between the 1960s and 1990s. As a result, a significant portion of assets in the Enersource rate zone are nearing the end of useful life and requiring renewal. In 2012, Enersource created formal Asset Management practices and utilized external independent expertise to complete annual Asset Condition Assessment studies. Based on learnings and evolving asset management processes, Enersource increased the frequency and detail of asset inspections which combined with additional analytical methods identified renewal investment needs in cables, wood poles as well as a number of transformers exhibiting signs of oil leaking which require to be replaced.

The asset management approach in the Enersource rate zone is based on attaining the best possible balance between risk, performance and cost as to maximize enterprise value on a sustainable basis while ensuring compliance with all legal and regulatory requirements.

The Horizon rate zone includes the cities of Hamilton and St Catharines. These service territories contain some of the oldest distribution system assets in the province. A significant portion of the Horizon Utilities rate zone asset infrastructure was installed during local economic expansion from the 1950s to 1970s, with a significant portion now largely due for renewal. Asset management practices in the Horizon Utilities rate zone are primarily geared toward paced and prioritized system renewal investments while ensuring system access investments due to redevelopment and intensification as well was general plant investments are made to support growth and efficient daily operations. The Horizon Utilities DSP was developed based on asset management objectives aligned with corporate objectives to be the best performing utility, to grow the business profitably, to be a great place to work and to be easy to do business with. This corporate strategy drives the asset management framework which includes developing an asset strategy, planning and project selection practices that lead to work management and finally result reporting. Although the Horizon rate zone asset management strategy has evolved from the development of the Asset Management philosophy in 2008, it continues to largely focus on system renewal with a long term perspective. In comparison with the Horizon Utilities rate zone, the Enersource rate zone asset management approach reflects the recent change from system planning for greenfield growth to that of system planning for maintenance with growth from intensification and redevelopment.

As one of the fastest growing cities in Canada, the asset management approach in the Brampton rate zone is largely geared towards management of growth, maintenance of system performance levels and investments in assets to achieve the lowest long terms cost of ownership. Although Brampton has system renewal needs, in comparison to the other Alectra Utilities rate zones, the system investments needs are primarily drive by system access from greenfield growth and development. As Hydro One Brampton Netowrks Inc.introduced formal asset management practices during periods of growth, the asset management practices in the its service territory are set up to capture and store asset attribute data to analyze trends and proactively address emerging issues. In comparison, the Enersource rate zone asset management practices required effort to improve upon asset data from enhanced asset inspection practices, before prioritizing and determining system renewal investments.

The asset management approach in the PowerStream rate zone is equivalently geared towards addressing system needs necessary to ensure connection and system capacity to meet growth demands as well as to renew certain sub-standard assets to facilitate operational effectiveness and system reliability. The PowerStream rate zone asset management planning process incorporates key elements of asset knowledge, asset strategy and planning, asset management and decision making. It leverages in-house asset condition assessment processes combined with sophisticated software and multi-disciplinary reviews to determined relative value and risk associated with the portfolio of capital projects. In comparison with the Enersource rate zone, the asset management approach in the PowerStream rate zone includes consideration for smart grid investments, as well as system renewal investments that also harden or strengthen the overhead system to withstand the frequency and severity of storms.

G-SEC-3

Reference(s): Ex. 1/1/1, p. 5 and elsewhere

For each of the ICM projects in each of the three rate zones in which ICM projects are proposed, please identify the projects in prior years, or in test year base capital, that are most similar to the individual ICM project, and explain how the ICM project is not related to, part of, a continuation of, or an extension of the similar projects.

Response:

For the below response, similar projects have been defined as similar type of work.

BRZ:

In the 2014 – 2019 DSP, Hydro One Brampton Networks Inc. forecasted a five year anniversary true-up payment for the Pleasant TS in 2014 and a five year anniversary true-up payment for the Goreway TS in 2015.

The proposed 2018 ICM project is for a 10 year anniversary true–up payment which is distinct and separate from the previous 5 year true-up payments.

ERZ Rate Zone:

System Access:

The Evans and Cawthra project would be similar to the 2013 QEW various crossings project. Some of these projects also involved converting an overhead crossing to underground, however they are at different locations than the Evans to Cawthra project.

System Renewal:

Glen Erin and Montevideo, Glen Erin and Battleford, and Credit Woodlands & Wiltshire, are all similar to Ellengale Dr Rebuild. All these projects involve cable rebuilds and in some cases transformers replacement. There is a slight variation in km’s of cable and number of transformers but these differences are negligible. Each of these projects are distinct locations and are not continuous.

Tenth Line, Folkway & Erin Mills, and City Centre Drive are all similar projects in that they involve rebuilding of main line feeder cables. However, there is no comparator in the test year.

Lake & John and Church Street are similar projects, both are approximately 50 pole rebuild projects in urban areas. However, these is no comparator in the test year.

The PCB leaking transformer project is similar to the UG/OH Transformer and Equipment Renewal projects in the test year. The only difference is the volume of transformers being replaced. However, the program in the test year (base capital) is for units failing (not fit for continued service) in the given year, where the ICM project is for replacing the backlog of transformers. Locations of the transformers will also not be identical.

System Service:
The York MS rebuild is similar to the Ruben MS upgrade completed in the 2013 test year. These station rebuilds while similar are at distinct locations and not continuous.

PRZ Rate Zone

System Access:
Since 2010, the former PowerStream has been relocating overhead and underground plant to accommodate road widening and shifting of the boulevard to support the YRRT construction. The portion of work that will be completed in 2017 is related to different phases than that which is expected to be in-service for 2018. The work involved in 2018 on the Y2 and H2 is not an extension of the work currently being completed in 2017.

System Renewal:
There is no similar station switchgear replacement projects in 2017 to the station switchgear replacement at 8th line MS323.

The rear lot supply remediation in Royal Orchard (North) would be similar to the work at Royal Orchard (Baythorn) which is ongoing in 2017. However the remediation in Royal Orchard

(North) is in adjacent to the above area and is not part of, or continuation of the work completed in 2017.

The cable replacement at Steeles and Westminister (Vaughan) would be similar to the ongoing work in the Rutherford and Weston (Vaughan) in 2017, Henderson and Doncaster (Markham) in 2017, Mill St. and Boulevard (Tottenham) in 2017. However the Steeles and Westminister (Vaughan) is a different area and is not a part of or continuation of the work completed in 2017.

The cable replacement at Steeles and Fairview Heights (Markham) would be similar to the above work except that the system voltage is also being converted to the present day primary supply voltage of 27.6kV.

The planned circuit breaker replacement at Richmond Hill TS Bus B would be similar to the ongoing work at the Richmond Hill TS# bus A in 2017. These projects are separate and distinct as Bus A will be capitalized at the end of 2017. Bus B is incremental.

System Service

The system service projects Rebuild 27.6kV Poleline Warden Avenue from Hwy 7 from Major Mackenzie, Build Double Circuit 27.6kV Pole Line on 19th Avenue between Leslie Street and Bayview Avenue drive, Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 are distribution lines capacity addition projects. These are most similar to the following 2017 projects Rebuild Warden Avenue from Hwy 7 to 16th Avenue in , Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Avenue, Vaughan TS#4 Feeder Integration (Part 1).

The system service project Mill Street MS835 Transformer Upgrade in Tottenham is a stations capacity addition project and is similar to the Little lake MS (2017). The major difference is that MS835 involves adding capacity at existing station while Little lake MS involved building a brand new station. The Mill street MS835 project is in the Tottenham area and is not part of continuation of work ongoing in 2017 for station in Barrie area.

As identified in the business cases, each of these projects are separate and distinct from the previous years as those have been completed and energized. These are incremental to that which is being funded in rates. Consequently, they are included as ICM projects.

G-SEC-4

Reference(s): Ex. 1/1/1, p. 9, 10 and elsewhere

Please confirm that the most consistent message during the customer engagement was a request for lower rates, and explain why the Applicant has responded to that message by proposing a substantial increase in rates.

Response:

Yes, Alectra Utilities is mindful that electricity rates are the key concern among Residential and General Service customers. It is not surprising that when engaging customers on the topic of electricity, which the general public typically sees as a commodity product, people say they would like to pay less.

The vast majority of customers, engaged throughout the customer engagement process, are satisfied with the current level of reliability they experience; further, they expect Alectra Utilities to do what is necessary to maintain it. As customers learned more about their distribution system throughout the telephone surveys[1], they were asked to provide their feedback as it relates to needs and preferences. Throughout the surveys, the challenges and pressure the electrical distribution system is currently facing were explained. [Attachment 51, Appendix 5.0, Alectra Utilities Online Feedback Portal Layout, Pages 22, 23, 24, 43, 44, 45, & 46]. Customers were asked to consider these challenges in the context of a trade-off between reliability and cost. Most customers in the Enersource RZ and PowerStream RZ support some form of investment program that ensures a consistently reliable and modern distribution system. [Attachment 51, Customer Engagement Report, Pages 18, 23 & 26].

Alectra Utilities has reviewed the opinions of those customers who prioritize reduced rates. Alectra Utilities believes its proposed investment plan and resulting rate change is in line with the preferences and needs of a majority of its customers, as gathered throughout the customer engagement consultation.

[1] In the Enersource RZ and PowerStream RZ, 25-29% of customers identified that they are very familiar with the services provided by their electricity utility

Alectra Utilities has weighed both the customer sentiment that prioritizes lower rates, as well as the expectation that Alectra Utilities does what is necessary to maintain current levels of reliability, by pacing and deferring certain system expansion projects.

G-SEC-5

Reference(s): Various locations in the Application

With respect to the combined impact of the incremental capital modules proposed:

a) Please confirm that the total incremental capital funding being requested in the test year is $706,794 for Brampton RZ, $1,834,693 for Powerstream RZ and $1,962,111 for Enersource RZ, for a total of $4,503,598.
b) Please confirm that the subject rate riders are proposed to be in place for nine years, and thus are expected to recover approximately $40.5 million from customers over that period, in addition to escalating rates.
c) Please confirm that the Applicant anticipates filing incremental capital module applications in all subsequent years until its next rebasing.
d) Please confirm that the incremental revenue from applications in all years for incremental capital in amounts similar to the current application would be approximately $203 million of incremental recoveries from customers over that period, over and above escalating rates under IRM.
e) Please confirm that, in that scenario, the opening rate base in the rebasing year would still be more than $500 million higher as a result of incremental capital projects, all of which would have to be recovered from customers in the future, along with the cost of capital on that additional rate base.

Response:

a) The total incremental capital funding being requested for 2018 for the Brampton RZ is $706,794 as indicated in Table 67 – Incremental Revenue Requirement – Brampton RZ, located at Exhibit 2, Tab 2, Schedule 10, p.12. The total incremental capital funding being requested for 2018 for the PowerStream RZ is $1,834,693 as indicated in Table 104 – Incremental Revenue Requirement – PowerStream RZ, located at Exhibit 2, Tab 3, Schedule 10, p.33. The total incremental capital funding being requested for 2018 for the Enersource RZ is $1,962,111 as indicated in Table 145 – Incremental Revenue Requirement – Enersource RZ, located at Exhibit 2, Tab 4, Schedule 11, p.46.

b) The proposed rate riders will be in place during the ten year rebasing deferral period that was approved by the Ontario Energy Board ("OEB") in its decision on the LDC Co Mergers Acquisitions, Amalgamations and Divestitures ("MAADs") Application (EB-2016-0025), issued on December 8, 2016.

Alectra Utilities has requested approval to recover incremental capital annual funding for the PowerStream, Brampton and Enersource rate zones totaling $4,503,598. Alectra Utilities is expected to recover approximately $40.5 MM over the rebasing deferral period. Alectra

Utilities will have mechanistic adjustments to rates, according to the OEB's Price Cap formula, which adjusts for inflation less a productivity factor.

Section 7.4 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014, states that:

> "*At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.*"

c) Alectra Utilities is eligible to file Incremental Capital Module ("ICM") applications for any of its rate zones that are on a Price Cap IR rate plan, during the rebasing deferral period. This is consistent with both the OEB's *Rate-Making Associated with Distributor Consolidation*, dated March 26, 2015 (p.9-10) and the *Handbook to Electricity Distributor and Transmitter Consolidations* released on January 19, 2016 (page 17). In the Oral Hearing related to the Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") application, Alectra Utilities' witnesses identified that this was an expectation ((EB-2016-0025), Oral Hearing Transcript, Vol 2, p.145, lines 18-22).

Alectra Utilities expects that it will have a need to file ICM applications periodically through the rebasing deferral period. Such need will be evaluated annually, in the context of the ICM criteria. Alectra Utilities cannot confirm that it will file ICM applications in each year of the rebasing deferral period.

d) Alectra Utilities cannot confirm the amounts of future ICM applications. Alectra Utilities will evaluate its capital funding requirements, annually. A determination of the extent of the application required will be made at that time.

e) Please see Alectra Utilities' response to part d), above.

HRZ-SEC-6

Reference(s): Ex. 2/1/2, p. 3

Please provide details of the impact of the change in the Horizon capitalization policy, both in the test year and in each of the next three future years. Please confirm that the Applicant is seeking the approval of the Board to the change.

Response:

As part of the amalgamation of PowerStream, Horizon Utilities and Enersource, PowerStream was identified as the "acquirer", under the International Financial Reporting Standards ("IFRS") business combination standard. IFRS requires that all entities in the new organization adopt the acquirer's policy. Consequently, Alectra Utilities has adopted PowerStream's capitalization policy for the Horizon Utilities and Enersource RZs. Table 1 below provides the amounts capitalized for Horizon Utilities RZ:

Table 1 – Impact of Capitalization Change – Horizon Utilities RZ

	2017	**2018**	**2019**	**2020**	**2021**
Direct Labour Costs	$1,726,949	$1,794,753	$1,821,276	$1,857,701	$1,894,855
Benefit Costs	$436,627	$450,321	$465,135	$474,438	$483,927
Material Handling Costs	$2,354,025	$2,376,376	$2,372,349	$2,406,103	$2,442,165
Fleet Costs	$1,762,653	$1,710,575	$1,720,082	$1,805,723	$1,894,314
Total Impact	**$6,280,253**	**$6,332,025**	**$6,378,842**	**$6,543,966**	**$6,715,261**

Generally, each year more costs will be capitalized for the Horizon Utilities RZ, as compared to the capitalization policy before the merger. Below are the details of the changes for each category listed in Table 1, above:

<u>Direct labour</u>: The result of this change is more salaries and benefits will be allocated to capital programs relating to network planning, standards, records and customer account set up.

<u>Benefit Costs</u>: The result of this change is that additional benefits such as post-retirement benefits and safety wear are now included in the pool of benefits and therefore allocated to capital projects.

Material Handling Costs: The result of this change is that additional supply chain costs such as the salary and benefits of stores personnel; small tools and depreciation of stores equipment are now allocated to all materials issued out from inventory and therefore allocated to capital projects.

Fleet Costs: The result of this change is that additional fleet and logistics costs such as the salary and benefits of fleet maintenance personnel; small tools and depreciation of fleet are now included in the fleet rate allocated to capital projects.

Alectra Utilities will adjust its results for its next annual filing for the Horizon Utilities RZ to Horizon Utilities on a stand-alone basis, consistent with the Settlement Agreement.

HRZ-SEC-7

Reference(s): Ex. 2/1/2, p. 4

Please provide all internal documents of the Applicant or its predecessors estimating the costs and benefits of moving the Horizon RZ to monthly billing, including any that estimate the specific impact of the June date.

Response:

Alectra Utilities provides the following internal documents which identify its estimated costs and impacts of transitioning the Horizon Utilities rate zone to monthly billing:

- The attached response (HRZ-SEC-7_Attach 1_Monthly Billing CLD) from the Coalition of Large Distributors ("CLD") which includes Horizon Utilities, dated October 9, 2014. This document includes the benefits and impacts of monthly billing as anticipated by the CLD and Horizon Utilities' estimated incremental operating expenses of $1.5MM annually and $0.5MM of one-time capital and operating expenses related to the initial implementation.

- Horizon Utilities' request as part of its 2016 Annual Update Filing to establish a new deferral account to support its transition to monthly billing. As filed in EB-2015-0075, Tab 2, Page 44 of 61, and as originally identified in Horizon Utilities' response to Interrogatory 2-Energy Probe-11 in its 2015 Custom IR Application (HRZ-SEC-7_Attach 2_IR 2-Energy Probe-11 Comments), the transition to monthly billing "*would require one-time implementation costs that are forecasted to be approximately $0.5MM. This cost includes: the development of implementation plans; testing; documentation and training; the provision of necessary programming changes for the Customer Information System; and the development of a customer communications strategy and related materials. Incremental annual operating expenditures are anticipated to be approximately $1.4MM annually (adjusted for inflation). These costs include: increased paper, printing, and mailing / postage expenditures corresponding to increased billing volumes and Call Centre requirements. Horizon Utilities estimated it will require an additional five Call Centre staff to manage the increased call volumes arising from monthly billing. Approximately $0.84MM of this annual expenditure corresponds to additional postage expense; which has increased at super-inflationary levels and may continue to do so*".

- An internal document (HRZ-SEC-7_Attach 3_MergeCo Monthly Billing Analysis) drafted in 2016 which estimates the impact to MergeCo's operating expenditures as a result of the transition to monthly billing. Note that this assessment was created prior to the OEB's decision that Horizon Utilities must transition its customers to monthly billing prior to June 30, 2017.

- An internal document (HRZ-SEC-7_Attach 4_Monthly Billing Assumptions Horizon Utilities) providing the estimated capital impacts, incremental operating cost expenditures and working capital impacts as estimated in 2016.

- Section 2.4.3 of MergeCo's 2017 to 2021 Financial Plan (HRZ-SEC-7_Attach 5_2017 to 2021 MergeCo Financial Plan) drafted in 2016 which provides the monthly billing impact on Cash to Alectra Utilities, inclusive of Horizon Utilities' transition to monthly billing in June 2017.

Alectra Utilities transitioned its Horizon Utilities Rate Zone customers to monthly billing in May and June of 2017. Although some stabilization efforts continue, Alectra Utilities estimates its actual one time implementation costs for monthly billing to be approximately $340,000 as provided in Table 1, below.

Table 1: Estimated Implementation Expenses related to the implementation of monthly billing in the Horizon Utilities rate zone

	Estimated one-time implementation costs
Programming - Customer Information System and bill print	$40,000
Project management and internal labour costs	$100,000
Total Capital Expenditures	**$140,000**
Miscellaneous Operating expenses related to process changes and training	$54,200
Incremental Call Centre support - 2 agents	$42,456
Incremental backoffice labour expenditures - 3 Clerks	$63,683
Customer Communications strategy	$35,500
Total Operating Expenditures	**$195,839**
TOTAL EXPENDITURES AS A RESULT OF MONTHLY BILLING	**$335,839**

Alectra Utilities also provides its incremental operating expenditures as a result of monthly billing based upon its experience to date. Incremental monthly costs are estimated to be $130,000 per month as provided in Table 2, below.

Table 2: Estimated monthly incremental expenditures after the implementation of monthly billing in the Horizon Utilities rate zone

	Estimated Incremental Operating Expenditures per month [current 2017 rates / charges]
Incremental costs related to in-house printing	$1,442
Mail machine continegency - DirectWorx	$4,000
Incremental Postage expense	$83,030
Incremental consumables - paper, envelopes, return envelopes	$27,325
Incremental backoffice labour expenditures - 3 Clerks	$10,614
ESTIMATED INCREMENTAL EXPENDITURES AS A RESULT OF MONTHLY BILLING	**$126,411**

October 9, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

via RESS and email

Dear Ms. Walli:

RE: **Draft Report of the Board: Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance**
Board File No.: EB-2014-0189

On September 18, 2014, the Ontario Energy Board ("Board" or "OEB") posted a Draft Report of the Board on Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance (EB-2014-0198).

This is the submission of the Coalition of Large Distributors ("CLD"). The CLD consists of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc. This submission has been filed via the Board's web portal and two (2) requisite paper copies have been couriered to the Board.

General Comments

The CLD is appreciative of opportunities afforded by the Board to engage in constructive, meaningful consultation on matters of Board policy. The CLD has a track record of regularly contributing ideas and opinions on topics of interest to the Board that have the potential to impact the operations of CLD members and, crucially, their customers, most recently evidenced by the CLD's submission on Distribution System Reliability Targets (EB-2014-0189).

The CLD participates in these important policy discussions because it is uniquely positioned to bring forth the perspective of large distributors which can, and often do, differ from other Board stakeholders, including local distribution companies ("LDC") of other sizes.

CLD members know their customers. Through the normal course of business, members are in contact with ratepayers on a daily, multi-modal basis. Members are also making conscious efforts to concord with Board policy within the Renewed Regulatory Framework for Electricity ("RRFE") which emphasizes that services be "provided in a manner that responds to <u>identified</u> customer preferences" [emphasis added].[1]

It is within this context that the CLD expresses its keen interest in the main conclusion of the Draft Report: "the Board is of the view that one of the most effective ways to achieve these objectives is to have all non-seasonal electricity residential customers in Ontario billed on a monthly basis [by] January 1, 2016."[2]

The Draft Report suggests "that timely and accurate billing is essential to customer satisfaction." As a broad, principled statement, the CLD agrees that timely and accurate billing is one of many components that contribute to customer satisfaction. Reliability, reduced outage times and value for money are other important components of customer satisfaction.

The Draft Report states further that the Board wants to ensure that customers "have the information to gain a better understanding of their energy consumption so that they can better manage that consumption and control their costs."[3] On this point as well the CLD agrees with the Board. For example, all CLD members participate in the peakSaver Conservation and Demand Management program which provides customers with the opportunity to obtain an in-home display that provides near real-time consumption data.

However, the CLD wishes to better understand the connection between these areas of general agreement and the Board's position on mandatory monthly billing. To be more specific, the CLD is interested in better understanding and having an opportunity to review the evidence that convinced the Board that the benefits customers gain by receiving a monthly electricity bill warrants the required investment and the corresponding rate increases needed to implement this policy.

Accordingly, the CLD does not support the recommendation of mandating monthly billing for residential customers. The CLD strongly advocates that this decision continue to be left to the discretion of individual LDCs as informed by the preferences of their customers.

To support the Board's work going forward, the CLD suggests that prior to any mandatory implementation of monthly billing that the Board consider other approaches and consult on those approaches with customers, LDCs and other stakeholders to determine if mandatory monthly billing is the preferred approach for all residential customers in all parts of the province.

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[1] Report of the Board, *Renewed Regulatory Framework for Electricity Distribution: A Performance-Based Approach*, p. 2.

[2] Draft Report of the Board, *Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance,* p. 8. (EB-2014-0198).

[3] Ibid.

The remainder of this document will cover four points:

1. The ongoing costs to customers as a result of mandating monthly billing are significant and the offsetting benefits are highly unlikely to lead to a cost neutral outcome for all distributors.
2. The CLD has not seen any evidence that suggests increasing billing frequency from bi-monthly to monthly will encourage customers to change their consumption behaviour.
3. Responses to the questions of the Consultation on Monthly Billing.
4. Responses to the questions of the Consultation on Estimated Billing.

Costs and Benefits of Monthly Billing

Costs

The CLD submits that any undertaking that doubles the volume of customer bills and payments processed can be expected to result in material operating and capital costs, including those associated with one-time project implementation work and recurring expenditures driven by volume increases.

Many of the specific cost drivers associated with the contemplated monthly billing transition are listed below; the exact cost of each will vary by distributor depending on customer volumes, the state and modularity of their customer information and billing systems, complexity of the metering infrastructure, bill printing and payment processing arrangements, call centre staffing and other related factors. The Board will no doubt want to consider costs of implementation, including the following.

Capital Costs:

- Billing System hardware and software upgrades and expansions driven by volume increases;
- Advanced metering infrastructure testing and configuration;
- Capitalized IT labour related to project planning and execution, testing and issue rectification; and,
- Contingency reserves.

Operating Costs:

One-Time / Temporary Costs:

- Process design, mapping and scenario analysis;
- Integration of new process(es) with existing operating procedures;
- Performance testing, accuracy validation, and pre-emptive issue rectification;
- Policies and procedures review and redesign;
- Billing, metering, collections and call centre staff training;
- Temporary call centre agents to assist with initial call volume increases;
- Customer communication and expenses related to customer change management
- Third party supplier and service provider contract negotiation (e.g., bill printing);
- Temporary staffing to cover project team member redeployment; and,

- System deployment and post-deployment support;

Recurring Costs:

- Paper, printing and postage costs – regular bills and inserts;
- Paper, printing and postage costs – reminder letters;
- Sustained call volume increases;
- Meter data management expenditures (e.g., exceptions investigations could effectively double);
- Billing staff increases to maintain current preparation timelines at higher volumes;
- Payment processing staff increases to maintain current processing timelines;
- Collection expenses (increased auto-dialler usage costs, additional staff).
- Customer Service staff increases to maintain ESQR telephone accessibility compliance due to any increase in call volumes resulting from higher billing frequency;

On total costs, the CLD submits the following:

- Toronto Hydro estimates its incremental ongoing operating expenses driven by monthly billing transition within the contemplated timelines to be $6.1M, not including approximately $5.2M to $8.3M of incremental one-time capital and operating costs.
- Veridian estimates its incremental ongoing operating expenses to be $0.8M annually.
- Horizon Utilities estimates its incremental ongoing operating expenses to be $1.5M annually, not including $0.5M of incremental one-time capital and operating expenses related to the initial implementation.
- PowerStream estimates its ongoing incremental operating expenses to be approximately $3M annually with additional capital expenditures for implementation in the range of $5M to $8M.
- Enersource estimates its ongoing incremental operating expenses to be approximately $1.2M, not including $0.5M to $0.75M of incremental one-time capital and operating costs.

Finally, a transition to monthly billing would effectively cause customers to advance on month of their electricity bills, which may be viewed negatively from a cash flow perspective.

Benefits

CLD members expect that the monthly billing would improve cash flow by reducing short-term financing costs which are recovered through the working capital allowance built into a distributor’s rate structure. From the customer’s perspective, the materiality of such benefits will vary by the degree to which retail revenue lag can be reduced as result of a transition to monthly billing.

On this benefit, the CLD submits the following:

- Toronto Hydro estimates that a transition to monthly billing would result in a revenue requirement reduction of approximately $1.9M, or 0.3% of its applied-for 2015 service revenue requirement, due to reduced Working Capital Allowance (“WCA”) amounts.

- Veridian estimates a transition to monthly billing would result in a revenue requirement reduction of approximately $0.4M due to reduced WCA amounts.
- Horizon Utilities estimates a transition to monthly billing would result in a revenue requirement reduction of approximately $1.5M due to reduced WCA amounts.
- PowerStream estimates a transition to monthly billing would result in a revenue requirement reduction of approximately $0.7M, or 0.43% of service revenue requirement, due to reduced WCA amounts.
- Enersource estimates a transition to monthly billing would result in a revenue requirement reduction of approximately $1.5M due to reduced WCA amounts.

The Draft Report also lists the arrears and bad debt expenditures as potential sources of benefits that would offset the costs of transitioning to monthly billing. The CLD is not aware of any evidence that would substantiate the conclusion that arrears or bad debt expenditures will be reduced as a result of switching from bi-monthly to monthly billing. The only CLD member to transition to monthly billing (Hydro Ottawa) has only done so earlier this year, however the nature of, and the regulations regarding, arrears/collection/bad debt write-off activities does not allow Hydro Ottawa to reliably assess the impact of any corrective activities in these areas for some time.

The CLD encourages the OEB to work with distributors that have implemented transitions to monthly billing over the past decade to empirically assess the materiality of anticipated bad debt/arrears benefits. It would be equally informative to undertake an empirical evaluation of a portion of total customer arrears that are driven by customers' inability or unwillingness to make a timely payment for a larger (two-months' worth of consumption) electricity bill at once. Absent the insights on a relationship between bill amounts/frequency and customers' propensity to pay them on time, the CLD cannot comment further on the relationship between monthly billing and the expectation of a reduction in the expenditures associated with late-/non-payments.

The Draft Report proposes that ongoing additional costs could be offset through a higher penetration of e-billing. Many of the CLD members have encouraged e-billing options in the past and continue to promote e-billing to their customers with some, if limited, customer participation. It is unlikely that any significant incremental gains will be made in this regard to offset future costs that cause upward pressure on distribution rates.

With regards to the benefits of more frequent opportunities to communicate with customers through monthly bills, the CLD submits that it is difficult to objectively quantify. There are already other cost-effective and widely adopted communication media that can be more easily measured, such as distributors' websites, Facebook or Twitter. At the same time, it is relatively simple to calculate the incremental cost of increased communication through bills, as they would equal the costs of additional bill insert drafting, design and printing, less any potential volume-based savings that utilities could conceivably realize depending on their specific circumstances (e.g., third-party service provider agreements).

Should the Board mandate monthly billing for residential customers, the CLD submits that any incremental, prudently incurred costs resulting from this change must be recoverable from customers in a timely manner (i.e., prior to its next rebasing period). Alternatively, the Board should allows utilities to minimize incremental costs by coordinating the implementation of monthly billing with another major customer billing system upgrade (see response Question 1 below).

Effectiveness of Mandatory Monthly Billing

The impetus for the Board to find new means of helping ratepayers manage their electricity costs is one that is shared by the members of the CLD. The survey undertaken by the Board is helpful in illuminating the degree to which monthly billing has penetrated utility operations.

However, the questions posed do not provide a basis for assessing whether there is a reasonable correlation between monthly billing and encouraging conservation, one of the stated objectives of the Board's proposal. By the same inference, twice-monthly billing, weekly billing or billing on any other shorter interval would be equally valid alternatives to bi-monthly billing. Until more information about the conservation effect of billing frequency is available, the CLD supports a continuation of the status quo which allows utilities to retain the discretion to implement monthly billing.

In addition, current Board policy,[4] which stipulates that utilities on bi-monthly billing cycles must offer equal billing plans to its residential customers, runs counter to the stated objective of mandatory monthly billing. Customers enrolled in these Board-mandated programs are subject to a price signal only once per year at the annual reconciliation. Accordingly, because the price signal to these customers is not dynamic, there should be no expectation of any incremental conservation from these customers if monthly billing is mandated. Moreover, it is possible that moving customers to a monthly billing cycle would encourage a greater uptake of equal monthly payment plans that would further mitigate expected conservation gains.

Responses to Consultation on Monthly Billing

For the electricity distributors that do not offer monthly billing, what are the barriers faced in meeting the Board's goal of having all residential customers moved to monthly billing by January 1, 2016?

The CLD anticipates that switching to monthly billing can be expected to generate significant expenditures associated with accuracy testing and verification. This is of particular relevance given the inclusion of a billing accuracy metric on the recently instituted OEB Distributor Scorecard.

CLD members conduct extensive and high-volume billing system tests each time there are changes to any billing determinants, such as those driven by Regulated Price Plan (RPP) adjustments, rate case decisions, or changes to the amounts of pass-through items such as Retail Transmission Service Rates (RTSR), Rural and Remote Electricity Rate Protection (RRRP) and others. Conducting extensive performance tests prior

[4] *Standard Supply Service Code*, Sections 2.6.2 and 2.6.2B.

to implementing any billing determinant changes allows utilities to maintain customer satisfaction and prevent significant costs associated with rectification of incorrectly issued bills, among other reasons.

The need for such tests (at higher than normal volumes) is paramount following major process changes, such as a scenario where the volumes of bills issued each day doubles and the time to proactively rectify any issues identified prior to sending the bill is effectively reduced in half.

There are also indirect costs on utility operations associated with an undertaking of this magnitude. Some CLD members estimate that a project of this scale, scope and sophistication would take a significant amount of time to implement, and would require significant human and financial resource allocations. A January 1, 2016 mandated implementation date is therefore aggressive and would introduce risk to a successful implementation.

For example, utilities may be faced with postponing or re-prioritizing other customer care-related operating or capital projects planned for the same timeframe that may have been implicitly or explicitly approved by the OEB in past rate proceedings. The impact of reshuffling these capital projects to accommodate a monthly billing project will affect the capital plans of utilities for many years that will have different corresponding impacts on utilities. While project re-prioritization is a common feature of electricity distribution operations, postponing certain planned investments or process modifications to allocate the resources to an externally mandated undertaking can result in a material impact on service quality, customer satisfaction, and other operational areas. These risks should be considered in light of the proposed short-term time line for this initiative.

In addition, the CLD is also aware of a number of other known and potential regulations impacting customers in this same proposed timeframe, including: the elimination of the Ontario Clean Energy Benefit (December 31, 2015); the elimination of the Debt Retirement Charge for certain customer classes; new or enhanced low-income programs; and, on-bill financing for conservation projects. Each of these are significant projects in themselves, will impact Customer Information Systems, require significant testing and process changes and require customer change management.

The CLD submits that material implementation of cost efficiencies can be leveraged if a transition to monthly billing occurs concurrently with other major planned customer information and billing system upgrades or modifications. When implemented alongside another planned major project of similar nature, efficiencies in billing cycle adjustments can be gained in areas such as testing and verification, training, temporary call centre staff increases and other similar one-time expenditures. Given that distributors are in different points of their customer care and billing hardware and software lifecycles, the OEB may consider establishing a target (5- or 10-year) window for such a transition to occur, in place of a rigid sector-wide timeframe.

Finally, if mandated for all utilities, consultants required to assist utilities in transitioning to monthly billing will be in very high demand and likely force utilities to pay more than would otherwise be necessary to meet the Board’s imposed deadline.

Should seasonal customers also be billed on a monthly basis? What are the barriers to moving to monthly billing? What are the offsetting benefits such as reduced costs?

In the event monthly billing for non-seasonal residential customers is mandated by the Board, seasonal residential customers should also be moved to monthly billing. It is likely that the cost of maintaining two separate billing schedules would not be sufficient to offset the savings resulting from the reduced billing volumes for those customers.

Responses to Consultation on Estimated Billing

Are there circumstances that should be considered as exceptions to the requirement for all residential consumers to receive bills based on actual meter reads?

The CLD believes it would be unreasonable to require that all residential customers' bills be based on actual meter reads because the conditions necessary to permit 100% accurate meter reads are beyond the reasonable control of the utility.

There are several instances where a customer's bill cannot be based on actual meter reads, including:

- Mechanical meter failure;
- Communication failure (Radio Frequency or landline) where there is no end read to account for the missing Validation, Estimation and Editing;
- Meter tampering that causes the meter to fail;
- Environmental circumstances that cause the meter to fail or the communications link to fail;
- Delays in gaining access to read a failed meter or install a replacement meter; and,
- Cases where customers have not allowed the utility to install a smart meter.[5]

Are there any barriers to moving to eliminate estimated billing? Are these offset by any benefits?

Meter failures in the field can only be minimized and not entirely eliminated through cost-effective maintenance and repair programs. Potential solutions may require wholesale changes to the status quo including switching out meters more frequently to capitalize on greater software processing capability of new meters. Estimated billing is therefore inevitably necessary for the foreseeable future.

[5] The Board acknowledges that there are still instances of this, noting that smart meters have been deployed to "virtually all" residential customers. Ref: Draft Report of the Board, *Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance,* p. 10. (EB-2014-0198).

For those limited circumstances where an estimated bill may be required, what is the appropriate methodology to be used in estimating the data?

There are at least two methods of estimating bills with some degree of accuracy:

- Many Customer Information Systems have robust estimation algorithms that can be used to estimate gaps in actual meter reads for the purposes of billing.
- Absent this capability, a utility can use historical consumption over the same prior period to gauge and estimate an approximate amount of consumption.

Should the policy establish a similar measure to that in the GDAR (less than 0.5% of meters with no read for four consecutive months)? If so, what should this measure be and should there be a disincentive for not meeting the measure?

The near full adoption of smart meters in the distribution sector would leave very few customers in this category and therefore limit the value provided by establishing and maintaining such a category and the associated cost of doing so. The Board's billing accuracy measure on the Scorecard already sufficiently captures this compliance information.

Yours truly,

[Original signed on behalf of the CLD by]

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2-Energy Probe-11

Ref: Exhibit 2, Tab 4, Appendix 2-3

a) Does Horizon have any plans to move customers from bi-monthly to monthly billing?

b) If all customers were moved to monthly billing, please show the impact on the overall working capital percentage along with the changes in days for the components of the revenue lag and expense lead, and any change associated with the HST.

c) If Horizon does move some or all customers to monthly billing in 2015-2019, would this adjustment be part of the annual adjustment to the working capital calculation? If not, why not?

Response:

Subsequent to the submission of its Application, Horizon Utilities reviewed the inputs used to calculate the Revenue Lag of 27.06. It determined that some of the revenue allocations between monthly and bi-monthly billing were incorrect. Navigant Consulting Inc. recalculates the Revenue Lag to be 25.02 days, based on the correct revenue allocations. The revised Revenue Lag of 25.02 has been used to calculate a revised Working Capital Allowance. This revision results in a reduction in the Working Capital Allowance of 0.7% from 12.7% to 12.0%. Horizon Utilities has included a revised Lead/Lag Report from Navigant as an attachment to its response to 2-Staff-23a. Horizon Utilities response to part b) is based on the revised Working Capital Allowance of 12.0%.

a) Please see Horizon Utilities' response to Interrogatory 2-Staff-23b).

b) Horizon Utilities provides the impact of switching to monthly billing to its overall working capital percentage along with the changes in days for the components of the revenue lag and expense lead, and any change associated with the HST in an attachment to this response as 2-EP-11b_Attch 1_Impact of Switching All Customers to Monthly Billing. A summary of the impact is identified in Table 1 below:

Table 1

		2015	2016	2017	2018	2019
Revenue Lag Days	Current State	67.30	67.30	67.30	67.30	67.30
	Monthly Billing - all Customers	57.53	57.53	57.53	57.53	57.53
Expense Lead Days		no change				
Working Capital Allowance	Current State	12.0%	12.0%	12.0%	12.0%	12.0%
	Monthly Billing - all Customers	8.8%	8.7%	8.7%	8.7%	8.7%
Total Working Capital Requirement including HST	Current State	$70,287,875	$72,767,684	$75,440,421	$78,139,129	$80,754,758
	Monthly Billing - all Customers	$51,215,047	$53,005,107	$54,943,476	$56,945,822	$58,893,908

The transition to monthly billing results in the issuance of an additional 1.2MM invoices annually.

The transition would require one-time implementation costs that are forecasted to be approximately $0.5MM. This cost includes: the development of implementation plans; testing; documentation, and training; the provision of necessary programming changes for the Customer Information System; and the development of a customer communications strategy and related materials.

Incremental annual operating expenditures are anticipated to be approximately $1.4MM annually (adjusted for inflation). These costs include: increased paper, printing, and mailing/ postage expenditures corresponding to increased billing volumes and Call Centre requirements. Horizon Utilities estimates it will require an additional five Call Centre staff to manage the increased call volumes arising from monthly billing. Approximately $0.84MM of this annual expenditure corresponds to additional postage expense; which has increased at super-inflationary levels and may continue to do so.

Horizon Utilities has estimated the net impact on Revenue Requirement (summarized in Table 2 below) resulting from:

i) The reduction in Revenue Requirement corresponding to the reduction in Working Capital Allowance provided in Table 1 above (Refer to Table 3 below);
ii) The ongoing increase in Revenue Requirement corresponding to an increase in annual operating expenditures necessary to support monthly billing (Refer to Table 4 below);
iii) The increase in Revenue Requirement from 2015 to 2019 corresponding to the recovery of implementation costs for monthly billing (Refer to Table 5 below).

Table 2

Impact on Revenue Requirement from Change to Monthly Billing
($000s)

	Reference	**2015**	**2016**	**2017**	**2018**	**2019**	**Totals**
Impact on Revenue Requirement							
Reduction of Working Capital Allowance	Table 3	(1,358)	(1,407)	(1,460)	(1,528)	(1,592)	(7,346)
Increase in OM&A	Table 4	1,409	1,437	1,466	1,495	1,525	7,332
Implementation Impact	Table 5	(6)	74	157	150	143	520
Net Increase/ (Decrease)		44	104	163	117	76	505

Table 2 demonstrates that Revenue Requirement would increase approximately $0.5MM across 2015 to 2019 as a result of implementing monthly billing. Thereafter, the outcome is marginally positive to ratepayers following the full amortization of one-time implementation costs and under the cost and inflation assumptions identified above and in Tables 3 through 5 below. Horizon Utilities submits that there is relative ratepayer indifference to monthly billing insofar as the impact on their distribution rates.

Horizon Utilities has not evaluated customer preferences with respect to monthly vs. bi-monthly billing. There have been very few calls from customers in the past requesting monthly billing, which may suggest relative indifference. Customers seeking to make electricity payments monthly for budgeting purposes already have opportunity to do so through Horizon Utilities equal monthly payment plan. Based on historical billing amounts, Horizon Utilities computes the monthly billing amount and settles on any differences relative to actual charges on an annual basis.

It is clear that a transition to monthly billing would effectively cause customers to advance one month of their electricity bills, which may be viewed negatively from a cash flow perspective.

Table 3

Impact on Revenue Requirement
Reduction of Working Capital Allowance from Change to Monthly Billing
($000s)

Assumptions:						
Working Capital Rate	8.80%					
PILs Rate	26.50%					
Deemed Debt %	60.00%					
Deemed Equity %	40.00%					
	2015	**2016**	**2017**	**2018**	**2019**	**Totals**
Working Capital Allowance Impact						
Current State	70,288	72,768	75,440	78,139	80,755	[redacted]
Monthly Billing - All	51,215	53,005	54,943	56,946	58,894	[redacted]
Working Capital Impact	19,073	19,763	20,497	21,193	21,861	[redacted]
Cost of Capital						
Debt	3.38%	3.38%	3.38%	3.53%	3.65%	[redacted]
Equity	9.36%	9.36%	9.36%	9.36%	9.36%	[redacted]
Revenue Requirement						
Cost of Capital:						
Debt	387	401	416	449	479	2,131
Equity	714	740	767	793	818	3,833
PILs Gross-Up	257	267	277	286	295	1,382
Total	1,358	1,407	1,460	1,528	1,592	7,346

Table 4

Impact on Revenue Requirement
Increase in OM&A from Change to Monthly Billing
($000s)

Assumptions:						
OMA - Annual	1,400					
Inflation Rate	2.00%					
Working Capital Rate	8.80%					
PILs Rate	26.50%					
Deemed Debt %	60.00%					
Deemed Equity %	40.00%					
	2015	**2016**	**2017**	**2018**	**2019**	**Totals**
Cost of Capital						
Debt	3.38%	3.38%	3.38%	3.53%	3.65%	
Equity	9.36%	9.36%	9.36%	9.36%	9.36%	
Revenue Requirement						
OM&A	1,400	1,428	1,457	1,486	1,515	7,286
Cost of Capital:						
Debt	2	3	3	3	3	13
Equity	5	5	5	5	5	24
PILs Gross-Up	2	2	2	2	2	9
Total	1,409	1,437	1,466	1,495	1,525	7,332
Working Capital Impact	123	126	128	131	133	

Table 5

Implementation Costs - Monthly Billing
Impact of Increase in OM&A from Change to Monthly Billing
($000s)

Assumptions:

Implementation CapEx	500
Depreciable Life (Years)	5
CCA Rate	100.00%
PILs Rate	26.50%
Deemed Debt %	60.00%
Deemed Equity %	40.00%

	2015	2016	2017	2018	2019	Totals
Fixed Asset Continuity						
Opening Balance	-	450	350	250	150	
Additions	500					
Depreciation	(50)	(100)	(100)	(100)	(100)	
Closing Balance	450	350	250	150	50	
Average Balance	225	400	300	200	100	
UCC Continuity						
Opening	-	250	-	-	-	
Additions	500	-	-	-	-	
CCA	(250)	(250)	-	-	-	
Closing	250	-	-	-	-	
Cost of Capital						
Debt (Exhibit 5)	3.38%	3.38%	3.38%	3.53%	3.65%	
Equity (Exhibit 5)	9.36%	9.36%	9.36%	9.36%	9.36%	
Revenue Requirement						
Depreciation	50	100	100	100	100	450
Cost of Capital:						
Debt	5	8	6	4	2	25
Equity	8	15	11	7	4	46
PILs Gross-Up (1)	(69)	(49)	40	39	37	(1)
Total	(6)	74	157	150	143	520
PILs Calculation						
Cost of Equity Capital	8	15	11	7	4	46
Add:						
Depreciation	50	100	100	100	100	450
Deduct:						
CCA	(250)	(250)	-	-	-	(500)
PILs Income	(192)	(135)	111	107	104	(4)
PILs before Gross-Up	(51)	(36)	29	28	27	(1)
PILs Gross-Up	(69)	(49)	40	39	37	(1)

1) PILs Gross-Up only applies to change in Cost of Equity

c) Yes.

However, it is Horizon Utilities' expectation that it would commence recovery of one-time and ongoing incremental costs identified in b) at the same time as the adjustment to working capital.

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2-EP-11b_Attch 1_Impact of Switching All Customers to Monthly Billing

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As per updated filed report

2014 WORKING CAPITAL REQUIREMENT

2014

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2014 Expenses	2014 Working Capital Requirement
Cost of Power	67.30	32.86	34.44	9.4%	$514,946,434	$48,584,754
OM&A Expenses	67.30	7.30	60.00	16.4%	$64,986,015	$10,683,086
PILS	67.30	14.50	52.80	14.5%	$555,146	$80,303
DRC	67.30	25.59	41.70	11.4%	$32,180,619	$3,676,858
Interest Expense	67.30	(67.15)	134.45	36.8%	$9,519,067	$3,506,363
Total					**$622,187,281**	**$66,531,364**
HST						$2,925,521
Total - Including HST						**$69,456,886**
Working Capital as a Percent of OM&A incl. Cost of Power						**12.0%**

2015 WORKING CAPITAL REQUIREMENT

2015

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2015 Expenses	2015 Working Capital Requirement
Cost of Power	67.30	32.86	34.44	9.4%	$520,720,617	$49,129,543
OM&A Expenses	67.30	7.30	60.00	16.4%	$64,479,807	$10,599,871
PILS	67.30	14.50	52.80	14.5%	$2,874,217	$415,763
DRC	67.30	25.59	41.70	11.4%	$31,854,423	$3,639,588
Interest Expense	67.30	(67.15)	134.45	36.8%	$9,831,640	$3,621,500
Total					**$629,760,705**	**$67,406,264**
HST						$2,881,611
Total - Including HST						**$70,287,875**
Working Capital as a Percent of OM&A incl. Cost of Power						**12.0%**

2016 WORKING CAPITAL REQUIREMENT

2016

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2016 Expenses	2016 Working Capital Requirement
Cost of Power	67.30	32.86	34.44	9.4%	$542,171,542	$51,013,656
OM&A Expenses	67.30	7.30	60.00	16.4%	$65,940,947	$10,810,450
PILS	67.30	14.50	52.80	14.4%	$4,252,792	$613,496
DRC	67.30	25.59	41.70	11.4%	$31,531,534	$3,592,852
Interest Expense	67.30	(67.15)	134.45	36.7%	$10,204,633	$3,748,622
Total					**$654,101,448**	**$69,779,077**
HST						$2,988,607
Total - Including HST						**$72,767,684**
Working Capital as a Percent of OM&A incl. Cost of Power						**12.0%**

2017 WORKING CAPITAL REQUIREMENT

2017

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2017 Expenses	2017 Working Capital Requirement
Cost of Power	67.30	32.86	34.44	9.4%	$562,422,662	$53,064,095
OM&A Expenses	67.30	7.30	60.00	16.4%	$67,692,855	$11,128,065
PILS	67.30	14.50	52.80	14.5%	$4,496,240	$650,392
DRC	67.30	25.59	41.70	11.4%	$31,211,917	$3,566,177
Interest Expense	67.30	(67.15)	134.45	36.8%	$10,624,086	$3,913,398
Total					**$676,447,760**	**$72,322,128**
HST						$3,118,293
Total - Including HST						**$75,440,421**
Working Capital as a Percent of OM&A incl. Cost of Power						**12.0%**

2018 WORKING CAPITAL REQUIREMENT

2018

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2018 Expenses	2018 Working Capital Requirement
Cost of Power	67.30	32.86	34.44	9.4%	$583,269,859	$55,031,010
OM&A Expenses	67.30	7.30	60.00	16.4%	$69,773,217	$11,470,057
PILS	67.30	14.50	52.80	14.5%	$3,925,141	$567,781
DRC	67.30	25.59	41.70	11.4%	$30,895,541	$3,530,029
Interest Expense	67.30	(67.15)	134.45	36.8%	$11,632,105	$4,284,704
Total					**$699,495,863**	**$74,883,581**
HST						$3,255,548
Total - Including HST						**$78,139,129**
Working Capital as a Percent of OM&A incl. Cost of Power						**12.0%**

2019 WORKING CAPITAL REQUIREMENT

2019

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2019 Expenses	2019 Working Capital Requirement
Cost of Power	67.30	32.86	34.44	9.4%	$602,042,446	$56,802,187
OM&A Expenses	67.30	7.30	60.00	16.4%	$72,228,903	$11,873,749
PILS	67.30	14.50	52.80	14.5%	$4,021,290	$581,690
DRC	67.30	25.59	41.70	11.4%	$30,582,371	$3,494,247
Interest Expense	67.30	(67.15)	134.45	36.8%	$12,600,791	$4,641,521
Total					**$721,475,801**	**$77,393,394**
HST						$3,361,364
Total - Including HST						**$80,754,758**
Working Capital as a Percent of OM&A incl. Cost of Power						**12.0%**

As per switching all customers to monthly billing

2014 WORKING CAPITAL REQUIREMENT

2014

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2014 Expenses	2014 Working Capital Requirement
Cost of Power	57.53	32.86	24.67	6.8%	$514,946,434	$34,804,956
OM&A Expenses	57.53	7.30	50.24	13.8%	$64,986,015	$8,944,082
PILS	57.53	14.50	43.03	11.8%	$555,146	$65,448
DRC	57.53	25.59	31.94	8.7%	$32,180,619	$2,815,715
Interest Expense	57.53	(67.15)	124.68	34.2%	$9,519,067	$3,251,636
Total					**$622,187,281**	**$49,881,837**
HST						$761,026
Total - Including HST						**$50,642,863**
Working Capital as a Percent of OM&A incl. Cost of Power						**8.7%**

2015 WORKING CAPITAL REQUIREMENT

2015

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2015 Expenses	2015 Working Capital Requirement
Cost of Power	57.53	32.86	24.67	6.8%	$520,720,617	$35,195,230
OM&A Expenses	57.53	7.30	50.24	13.8%	$64,479,807	$8,874,412
PILS	57.53	14.50	43.03	11.8%	$2,874,217	$338,850
DRC	57.53	25.59	31.94	8.7%	$31,854,423	$2,787,174
Interest Expense	57.53	(67.15)	124.68	34.2%	$9,831,640	$3,358,408
Total					**$629,760,705**	**$50,554,074**
HST						$660,973
Total - Including HST						**$51,215,047**
Working Capital as a Percent of OM&A incl. Cost of Power						**8.8%**

2016 WORKING CAPITAL REQUIREMENT

2016

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2016 Expenses	2016 Working Capital Requirement
Cost of Power	57.53	32.86	24.67	6.7%	$542,171,542	$36,544,963
OM&A Expenses	57.53	7.30	50.24	13.7%	$65,940,947	$9,050,714
PILS	57.53	14.50	43.03	11.8%	$4,252,792	$500,004
DRC	57.53	25.59	31.94	8.7%	$31,531,534	$2,751,384
Interest Expense	57.53	(67.15)	124.68	34.1%	$10,204,633	$3,476,295
Total					**$654,101,448**	**$52,323,360**
HST						$681,747
Total - Including HST						**$53,005,107**
Working Capital as a Percent of OM&A incl. Cost of Power						**8.7%**

Monthly/bi-monthly customers (filed) VS all customers with monthly billing

2017 WORKING CAPITAL REQUIREMENT

2017

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2017 Expenses	2017 Working Capital Requirement
Cost of Power	57.53	32.86	24.67	6.8%	$562,422,662	$38,013,849
OM&A Expenses	57.53	7.30	50.24	13.8%	$67,692,855	$9,316,627
PILS	57.53	14.50	43.03	11.8%	$4,496,240	$530,074
DRC	57.53	25.59	31.94	8.7%	$31,211,917	$2,730,957
Interest Expense	57.53	(67.15)	124.68	34.2%	$10,624,086	$3,629,101
Total					**$676,447,760**	**$54,220,608**
HST						$722,868
Total - Including HST						**$54,943,476**
Working Capital as a Percent of OM&A incl. Cost of Power						**8.7%**

2018 WORKING CAPITAL REQUIREMENT

2018

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2018 Expenses	2018 Working Capital Requirement
Cost of Power	57.53	32.86	24.67	6.8%	$583,269,859	$39,422,900
OM&A Expenses	57.53	7.30	50.24	13.8%	$69,773,217	$9,602,949
PILS	57.53	14.50	43.03	11.8%	$3,925,141	$462,746
DRC	57.53	25.59	31.94	8.7%	$30,895,541	$2,703,275
Interest Expense	57.53	(67.15)	124.68	34.2%	$11,632,105	$3,973,432
Total					**$699,495,863**	**$56,165,302**
HST						$780,520
Total - Including HST						**$56,945,822**
Working Capital as a Percent of OM&A incl. Cost of Power						**8.7%**

2019 WORKING CAPITAL REQUIREMENT

2019

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	2019 Expenses	2019 Working Capital Requirement
Cost of Power	57.53	32.86	24.67	6.8%	$602,042,446	$40,691,729
OM&A Expenses	57.53	7.30	50.24	13.8%	$72,228,903	$9,940,927
PILS	57.53	14.50	43.03	11.8%	$4,021,290	$474,081
DRC	57.53	25.59	31.94	8.7%	$30,582,371	$2,675,873
Interest Expense	57.53	(67.15)	124.68	34.2%	$12,600,791	$4,304,328
Total					**$721,475,801**	**$58,086,938**
HST						$806,970
Total - Including HST						**$58,893,908**
Working Capital as a Percent of OM&A incl. Cost of Power						**8.7%**

MergeCo Impact of Transitioning to Monthly Billing *

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Operating Costs	**2,818,084**	**3,427,424**	**4,672,870**	**5,183,034**	**4,913,034**	**4,643,034**	**4,373,034**	**4,373,034**	**4,373,034**	**4,373,034**
Bill Processing	*1,595,910*	*1,903,439*	*2,891,574*	*3,637,731*	*3,637,731*	*3,637,731*	*3,637,731*	*3,637,731*	*3,637,731*	*3,637,731*
Payment Processing	*114,443*	*133,883*	*194,362*	*237,557*	*237,557*	*237,557*	*237,557*	*237,557*	*237,557*	*237,557*
Other On-going Costs	*212,254*	*263,942*	*410,794*	*497,746*	*497,746*	*497,746*	*497,746*	*497,746*	*497,746*	*497,746*
Total On-going Costs	***1,922,607***	***2,301,264***	***3,496,730***	***4,373,034***	***4,373,034***	***4,373,034***	***4,373,034***	***4,373,034***	***4,373,034***	***4,373,034***
Transitional FTE	*810,000*	*1,080,000*	*1,080,000*	*810,000*	*540,000*	*270,000*	-	-	-	-
Outsource Call Centre	*65,476*	*41,160*	*91,140*	-	-	-	-	-	-	-
Communication/Marketing	*20,000*	*5,000*	*5,000*	-	-	-	-	-	-	-
Total One-Time Operating Costs	***895,476***	***1,126,160***	***1,176,140***	***810,000***	***540,000***	***270,000***	-	-	-	-
Total Operating Benefits	**883,005**	**1,085,245**	**1,695,455**	**1,695,455**	**1,695,455**	**1,695,455**	**1,695,455**	**1,695,455**	**1,695,455**	**1,695,455**
Interest Expense Savings from Cash Flow Increase	*854,005*	*1,017,445*	*1,542,055*	*1,542,055*	*1,542,055*	*1,542,055*	*1,542,055*	*1,542,055*	*1,542,055*	*1,542,055*
Reduction in Bad Debt & LPC Expense	*29,000*	*39,000*	*67,000*	*67,000*	*67,000*	*67,000*	*67,000*	*67,000*	*67,000*	*67,000*
Increase in Collection Notice revenue	-	*28,800*	*86,400*	*86,400*	*86,400*	*86,400*	*86,400*	*86,400*	*86,400*	*86,400*
Total Ongoing Operating Benefits	*883,005*	*1,085,245*	*1,695,455*	*1,695,455*	*1,695,455*	*1,695,455*	*1,695,455*	*1,695,455*	*1,695,455*	*1,695,455*
Total Budgeted Operating Costs	**1,935,079**	**2,342,179**	**2,977,415**	**3,487,580**	**3,217,580**	**2,947,580**	**2,677,580**	**2,677,580**	**2,677,580**	**2,677,580**

Assumptions

*Assumes Monthly Billing start dates of Jan 1, 2017 for PowerStream; Sept 1, 2018 Enersource; Sept 1, 2019 Horizon & Brampton

Analysis assumes any inflation increase in costs would be offset by an increase in operating benefits

Analysis excludes any impact as a result of a change in working capital impact

Impact of Transitioning to Monthly Billing - OPEX Costs

Customer Data	PowerStream	Enersource	Horizon	Brampton
Total Customers	364,130	204,216	240,000	156,000
Total Residential / Small GS (Bi-Monthly) Customers	316,298	181,600	219,700	144,000
Total Residential E-Bill Customers	44,620	17,974	25,500	10,000
Total Residential E-Post Customers	-	12,605	6,000	3,700
Total Residential (PAP) AutoPay Customers	61,108	52,376	55,000	30,000
Total Residential (PAP) AutoPay Customers Bi-Monthly	42,838	22,655	-	20,000
Total Current Residential Letters/Notices	262,950	24,000	318,000	40,000
Total Incremental Residential Letters/Notices	-	48,000	-	-
Total Customer Calls per year	293,038	140,000	310,000	145,000

Annual Processing Costs - Ongoing	PowerStream Rates	PowerStream Full Year Bi-Monthly Costs	PowerStream Full Year Monthly Costs	PowerStream Increase / (Decrease)	Enersource Full Year Bi-Monthly Costs	Enersource Full Year Monthly Costs	Enersource Increase / (Decrease)	Horizon Full Year Bi-Monthly Costs	Horizon Full Year Monthly Costs	Horizon Increase / (Decrease)	Brampton Full Year Bi-Monthly Costs	Brampton Full Year Monthly Costs	Brampton Increase / (Decrease)	Brampton Rates
Bill Processing														
Regular Postage Customers	$ 0.80	$ 1,304,054	$ 2,608,109	$ 1,304,054	$ 724,901	$ 1,449,802	$ 724,901	$ 903,360	$ 1,806,720	$ 903,360	$ 1,250,880	$ 1,250,880	$ -	$ 0.80
Bill Print (includes paper, envelopes, etc…)	$ 0.163	$ 265,701	$ 531,402	$ 265,701	$ 147,699	$ 295,397	$ 147,699	$ 184,060	$ 368,119	$ 184,060	$ 254,867	$ 242,888	-$ 11,979	$ 0.21
E-Bill Customers ($0.14 + $0.05)	$ 0.19	$ 26,155	$ 52,310	$ 26,155	$ 20,490	$ 40,981	$ 20,490	$ 29,070	$ 58,140	$ 29,070	$ 22,800	$ 23,484	$ 684	$ 0.16
E-Post Customers	$ 0.39	$ -	$ -	$ -	$ 29,496	$ 58,991	$ 29,496	$ 14,040	$ 28,080	$ 14,040	$ 17,316	$ 17,316	$ -	$ 0.39
Total Annual Billing Costs		***$ 1,595,910***	***$ 3,191,821***	***$ 1,595,910***	***$ 922,585***	***$ 1,845,171***	***$ 922,585***	***$ 1,130,530***	***$ 2,261,059***	***$ 1,130,530***	***$ 1,545,863***	***$ 1,534,568***	***-$ 11,295***	
Payment Processing														
PAP/AutoPay Payment Processing	$ 0.064	$ 30,481	$ 46,931	$ 16,450	$ 31,525	$ 40,225	$ 8,700	$ 42,240	$ 42,240	$ -	$ 23,040	$ 23,363	$ 323	$ 0.05
Non-PAP/AutoPay Payment Processing	$ 0.064	$ 97,993	$ 195,986	$ 97,993	$ 49,622	$ 99,244	$ 49,622	$ 63,245	$ 126,490	$ 63,245	$ 87,552	$ 88,778	$ 1,226	$ 0.05
Total Annual Payment Processing Costs		***$ 128,474***	***$ 242,917***	***$ 114,443***	***$ 81,147***	***$ 139,469***	***$ 58,322***	***$ 105,485***	***$ 168,730***	***$ 63,245***	***$ 110,592***	***$ 112,140***	***$ 1,548***	
Other On-going Costs														
Billing & Collections letters/notices ($0.107 + $0.80)	$ 0.91	$ 238,496	$ 238,496	$ -	$ 21,768	$ 65,304	$ 43,536	$ 288,426	$ 288,426	$ -	$ 435,360	$ 435,360	$ -	$ 0.91
Olameter Collections	$ 185,252	$ 463,132	$ 648,384	$ 185,252	$ -	$ -	$ 92,626	$ -	$ -	$ 92,626	$ -	$ -	$ -	$ -
Idocs, Archiving & Retrieval ($0.14 view & $0.0075 archive)	$ 27,002	$ 27,002	$ 54,004	$ 27,002	$ -	$ -	$ 18,901	$ -	$ -	$ 18,901	$ -	$ -	$ 18,901	
Additional Licensing/Maintenance (IT costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Other On-going costs		$ 728,630	$ 940,884	$ 212,254	$ 21,768	$ 65,304	$ 155,063	$ 288,426	$ 288,426	$ 111,527	$ 435,360	$ 435,360	$ 18,901	
Total Annual Processing Costs - Ongoing		***$ 2,453,015***	***$ 4,375,622***	***$ 1,922,607***	***$ 1,025,501***	***$ 2,049,944***	***$ 1,135,970***	***$ 1,524,440***	***$ 2,718,215***	***$ 1,305,302***	***$ 2,091,815***	***$ 2,082,068***	***$ 9,155***	
Annual Processing Costs - One-time														
Transition FTE (2017-2023)														
Billing Exceptions	6.00			$ 540,000										
Payment Processing	3.00			$ 270,000										
Collection Activity	3.00			$ 270,000										
Total Annual FTE Transitional Costs		***$ -***	***$ -***	***$ 1,080,000***	***$ -***	***$ -***	***$ -***	***$ -***	***$ -***	***$ -***	***$ -***	***$ -***	***$ -***	
Customer Calls														
Outsource Customer Calls (15% increase for 6 months)	$ 3.92	$ 873,019	$ 938,495	$ 65,476	$ 548,800	$ 589,960	$ 41,160	$ 1,215,200	$ 1,306,340	$ 91,140	$ -	$ -	$ -	
Communications & Marketing														
Bill Inserts & local newspapers	$ 20,000		$ 20,000	$ 20,000			$ 5,000			$ 5,000			$ -	
Other One-time costs														
Other One-time costs	$ -			$ -			$ -			$ -				
Total One-time Costs		***$ 873,019***	***$ 958,495***	***$ 1,165,476***	***$ 548,800***	***$ 589,960***	***$ 46,160***	***$ 1,215,200***	***$ 1,306,340***	***$ 96,140***	***$ -***	***$ -***	***$ -***	
Total Incremental Operating Costs One-Time & Ongoing				***$ 3,088,084***			***$ 1,182,130***			***$ 1,401,442***			***$ 9,155***	

Impact of Transitioning to Monthly Billing - BENEFITS

		PowerStream			Enersource			Horizon		
Cash Flow increase (AR & Unbill) from Monthly Billing		31,629,800			18,160,000			21,970,000		
Bad Debt Expense		1,600,000			1,100,000			1,400,000		
LPC Revenue		1,700,000			1,500,000			1,200,000		
Annual Ongoing Benefits	**Assumption**	**Full Year Bi-Monthly Costs**	**Full Year Monthly Costs**	**Increase / (Decrease)**	**Full Year Bi-Monthly Costs**	**Full Year Monthly Costs**	**Increase / (Decrease)**	**Full Year Bi-Monthly Costs**	**Full Year Monthly Costs**	**Increase / (Decrease)**
Benefits										
Interest Expense Savings from Cash Flow Increase	2.70%			$ 854,005			$ 490,320			$ 593,190
Reduction in Bad Debt Expense	5.00%			$ 80,000			$ 75,000			$ 60,000
Reduction in LPC Revenue	-3.00%			-$ 51,000			-$ 45,000			-$ 36,000
Increase in Collection Notice revenue*	$ 9.00			$ -			$ 86,400			$ -
		$ -	*$ -*	***$ 883,005***	*$ -*	*$ -*	***$ 606,720***	*$ -*	*$ -*	***$ 617,190***
Total Annual Processing Costs - Ongoing				***$ 883,005***			***$ 606,720***			***$ 617,190***

MergeCo Synergy Savings of Transitioning to Monthly Billing

	2017	2018	2019	Total
Total Operating Costs	2,583,572	2,189,529	934,295	**$ 5,707,395**
Total Operating Benefits	1,223,910	1,021,670	411,460	**$ 2,657,040**
Total Operating Synergy Savings	1,359,662	1,167,859	522,835	**$ 3,050,355**

	2017	2018	2019	Total
Capital Synergy Savings Enersource & Horizon	-	725,000	300,000	**$ 1,025,000**

Monthly Billing Implementation Assumptions - Capital

Account	Budget Assumptions	January	February	March	April	May	June	July	August	September	October	November	December	Total
Outside Service Provider	Daffron				20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	**187,500**
Outside Service Provider	Added for COH non monthly				10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	**90,000**
Outside Service Provider	Costs to generate print files				5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	**45,000**
Labour	Development of Project Documentation	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	CIS Prep for purge/archival	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	CIS Prep for purge/archival	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	CIS Prep for purge/archival	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	CIS Prep for purge/archival	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	CIS Prep for purge/archival	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Finalize RFP for Outsource printing / mailing	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	Evaluate results, meet with vendors, recommendation	1,342	-	-	-	-	-	-	-	-	-	-	-	**1,342**
Labour	Evaluate results, meet with vendors, recommendation	1,326	-	-	-	-	-	-	-	-	-	-	-	**1,326**
Labour	Evaluate results, meet with vendors, recommendation	934	-	-	-	-	-	-	-	-	-	-	-	**934**
Labour	Evaluate results, meet with vendors, recommendation	936	-	-	-	-	-	-	-	-	-	-	-	**936**
Labour	Evaluate results, meet with vendors, recommendation	485	-	-	-	-	-	-	-	-	-	-	-	**485**
Labour	Evaluate results, meet with vendors, recommendation	658	-	-	-	-	-	-	-	-	-	-	-	**658**
Labour	Evaluate results, meet with vendors, recommendation	652	-	-	-	-	-	-	-	-	-	-	-	**652**
Labour	Evaluate results, meet with vendors, recommendation	708	-	-	-	-	-	-	-	-	-	-	-	**708**
Labour	Recommendation to Stakeholders, printing / mailing	-	467	-	-	-	-	-	-	-	-	-	-	**467**
Labour	Recommendation to Stakeholders, printing / mailing	-	442	-	-	-	-	-	-	-	-	-	-	**442**
Labour	Develop print SOW for Daffron programs	-	-	1,768	-	-	-	-	-	-	-	-	-	**1,768**
Labour	Develop print SOW for Daffron programs	-	-	934	-	-	-	-	-	-	-	-	-	**934**
Labour	Develop print SOW for Daffron programs	-	-	936	-	-	-	-	-	-	-	-	-	**936**
Labour	Develop print SOW for Daffron programs	-	-	969	-	-	-	-	-	-	-	-	-	**969**
Labour	Implement outsource solution to test system	-	-	-	884	884	884	884	-	-	-	-	-	**3,537**
Labour	Implement outsource solution to test system	-	-	-	467	467	467	467	-	-	-	-	-	**1,867**
Labour	Implement outsource solution to test system	-	-	-	936	468	468	468	-	-	-	-	-	**2,340**
Labour	Implement outsource solution to production	-	-	-	-	-	-	-	442	-	-	-	-	**442**
Labour	Implement outsource solution to production	-	-	-	-	-	-	-	467	-	-	-	-	**467**
Labour	Implement outsource solution to production	-	-	-	-	-	-	-	468	-	-	-	-	**468**
Labour	CIS Changes/requirements/reports/SOW	9,691	7,268	4,846	-	-	-	-	-	-	-	-	-	**21,805**
Labour	CIS Changes/requirements/reports/SOW	2,340	2,340	2,340	-	-	-	-	-	-	-	-	-	**7,019**
Labour	CIS Changes/requirements/reports/SOW	4,669	2,334	4,669	-	-	-	-	-	-	-	-	-	**11,671**
Labour	CIS Changes/requirements/reports/SOW	1,426	1,426	1,426	-	-	-	-	-	-	-	-	-	**4,279**
Labour	CIS Changes/requirements/reports/SOW	2,211	3,095	2,211	-	-	-	-	-	-	-	-	-	**7,516**
Labour	CIS Changes/requirements/reports/SOW	1,478	1,478	1,478	-	-	-	-	-	-	-	-	-	**4,435**
Labour	CIS Changes/requirements/reports/SOW	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	CIS Changes/requirements/reports/SOW	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Labour	testing of all changes/interfaces	-	-	-	-	6,511	6,511	6,511	-	-	-	-	-	**19,533**
Labour	testing of all changes/interfaces	-	-	-	-	1,938	1,938	1,938	-	-	-	-	-	**5,815**
Labour	testing of all changes/interfaces	-	-	-	-	4,421	4,421	4,421	-	-	-	-	-	**13,263**
Labour	testing of all changes/interfaces	-	-	-	-	1,867	1,867	1,867	-	-	-	-	-	**5,602**
Labour	testing of all changes/interfaces	-	-	-	-	1,404	1,404	1,404	-	-	-	-	-	**4,212**
Labour	testing of all changes/interfaces	-	-	-	-	986	1,478	1,478	-	-	-	-	-	**3,942**
Labour	testing of all changes/interfaces	-	-	-	-	951	1,426	1,426	-	-	-	-	-	**3,803**
Labour	Develop/Execute internal training & communications	-	-	-	-	934	934	934	-	-	-	-	-	**2,801**
Labour	Develop/Execute internal training & communications	-	-	-	-	930	930	930	-	-	-	-	-	**2,791**
Labour	Develop/Execute internal training & communications	-	-	-	-	840	840	840	-	-	-	-	-	**2,519**
Labour	Develop/Execute internal training & communications	-	-	-	-	884	884	884	-	-	-	-	-	**2,653**
Labour	Develop/Execute internal training & communications	-	-	-	-	969	969	969	-	-	-	-	-	**2,907**
Labour	Develop/Execute internal training & communications	-	-	-	-	986	986	986	-	-	-	-	-	**2,957**

Monthly Billing Implementation Assumptions - Capital

Account	Budget Assumptions	January	February	March	April	May	June	July	August	September	October	November	December	Total
Labour	Develop/Execute internal training & communications	-	-	-	-	951	951	951	-	-	-	-	-	**2,852**
Labour	Develop/Execute internal training & communications	-	-	-	-	263	263	263	-	-	-	-	-	**789**
Labour	Develop external communications	-	-	-	467	467	467	-	-	-	-	-	-	**1,401**
Labour	Develop external communications	-	-	-	6,978	465	465	465	930	930	930	930	930	**13,026**
Labour	Develop external communications	-	-	-	884	442	442	-	-	-	-	-	-	**1,768**
Labour	Develop external communications	-	-	-	485	485	485	-	-	-	-	-	-	**1,454**
Labour	Develop external communications	-	-	-	5,747	383	383	383	383	383	383	383	383	**8,812**
Labour	Develop external communications	-	-	-	3,290	658	658	658	658	658	658	658	658	**8,553**
Labour	Develop external communications	-	-	-	2,829	566	566	566	566	566	566	566	566	**7,354**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	3,256	3,256	-	-	**6,511**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	969	969	-	-	**1,938**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	2,653	2,653	-	-	**5,305**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	1,867	934	-	-	**2,801**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	1,872	936	-	-	**2,808**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	986	986	-	-	**1,971**
Labour	Deploy pilot phase and monitor	-	-	-	-	-	-	-	-	951	951	-	-	**1,902**
Labour	Implement for all customers / monitor / stabilize	-	-	-	-	-	-	-	-	-	-	-	934	**934**
Labour	Implement for all customers / monitor / stabilize	-	-	-	-	-	-	-	-	-	-	-	930	**930**
Labour	Implement for all customers / monitor / stabilize	-	-	-	-	-	-	-	-	-	-	-	884	**884**
Labour	Implement for all customers / monitor / stabilize	-	-	-	-	-	-	-	-	-	-	-	493	**493**
Labour	Implement for all customers / monitor / stabilize	-	-	-	-	-	-	-	-	-	-	-	475	**475**
Labour	Implement for all customers / monitor / stabilize	-	-	-	-	-	-	-	-	-	-	-	485	**485**
Total		**28,854**	**18,850**	**21,576**	**58,799**	**65,952**	**66,920**	**65,527**	**39,747**	**50,923**	**49,054**	**38,370**	**42,571**	**547,144**

Monthly Billing Implementation Assumptions - Operating and Depreciation Impacts (MMs)

Operating Expenditures

Account	Budget Assumptions	2016	2017	2018	2019	2020
Freight, Postage and Delivery (740000)	2016 ADJ - Monthly Billing - Outer year increase $1.0M increase - Postage - Notices, Invoices, Letters, Mills Courier	-	1.00	1.02	1.04	1.06
General Office Supplies (704000)	2016 ADJ - Monthly Billing - Outer year increase $50K - Envelopes $28.74 per 1000	-	0.05	0.05	0.05	0.05
General Office Supplies (704000)	2016 ADJ - Monthly Billing - Outer year increase $40K - Invoice bills $15,000 per 550,000		0.04	0.04	0.04	0.04
Training and Development (640000)	2016 ADJ - Monthly Billing Implementation		0.03			
Public Relations (773000)	2016 ADJ - Monthly Billing Implementation		0.08			
Consulting (753000)	2016 ADJ - Monthly Billing Implemenation - Backfill		0.10			
Total operating expenditures		**-**	**1.3**	**1.1**	**1.1**	**1.2**

Depreciation Expenditures

Account	Budget Assumptions	2016	2017	2018	2019	2020
Depreciation	Assumes in service date of June 2017 (5 year asset amortization period)	-	0.05	0.11	0.11	0.11
Total depreciation expenditures		**-**	**0.1**	**0.1**	**0.1**	**0.1**

Monthly Billing Implementation Assumptions - Working Capital (MMs)

Account	Budget Assumptions	2016	2017	2018	2019	2020
Accounts Receivable	30 day reduction in cash flow lags	-	(21.0)	-	-	-
Estimated impact to Net Financing charges, fav (unfav)		-	0.3	0.3	0.3	0.3

Net Income Impact Analysis - Monthly Billing Implemented in Daffron by June 30, 2017

Horizon Utilities Corporation
Electricity Distribution Operations
Results of Operations

(000s)	2017	2018	2019
Distribution services revenue:			
Fixed	-	-	-
Variable	-	-	-
Total distribution services revenue	-	-	-
Other rider/adder revenue	-	-	-
Total distribution services and other revenue	-	-	-
Non-distribution electricity revenue:			
Electricity revenue	-	-	-
Electricity cost of sales	-	-	-
Settlements of past accumulated variances	-	-	-
Net non-distribution electricity revenue	-	-	-
Net electricity revenue	-	-	-
Other income from operations	-	-	-
Total net revenue	-	-	-
Expenses:			
Distribution and utilization	1,290	1,111	1,133
Billing and collecting	-	-	-
Credit losses	-	-	-
General and administrative	-	-	-
Depreciation and amortization	55	109	109
Total expenses	1,345	1,221	1,243
Income from operating activities	(1,345)	(1,221)	(1,243)
Loss on sale and disposal of assets	-	-	-
Net financing charges	300	300	300
Income before taxes	(1,045)	(921)	(943)
Payments in lieu of income taxes	277	244	250
Net income	(768)	(677)	(693)
Total Modified IFRS adjustments, net of tax	-	-	-
Modified IFRS net income	(768)	(677)	(693)

MergeCo Financial Plan

2017 - 2021

2.4.3 Monthly Billing Impact

The following table summarizes the estimated impacts on Accounts Receivable ("AR") and net financing charges for MergeCo over the next five years resulting from the implementation of monthly billing based on the schedule below:

Table 15: Monthly Billing Impact on Cash ($MMs)

Description	2017	2018	2019	2020	2021	Total
Accounts Receivable	(53.6)	(18.2)	—	—	—	**(71.8)**
Estimated impact to Net Financing charges, fav (unfav)	1.5	1.9	1.9	1.9	1.9	**7.9**

The aforementioned favourable impacts to AR are based on the following forecasted monthly billing start dates:

- PowerStream - January 2017
- Horizon Utilities - June 2017
- Enersource - August 2018

The impact to AR is principally estimated as the product of the number of Residential and General Service<50kW customers and an average monthly bill of $100. The corresponding reduction in AR is $71.8MM. Reductions in average AR balances will have corresponding favourable impacts to net financing charges.

HRZ-SEC-8

Reference(s): Ex. 2/1/6, p. 6, 7

Please recalculate Tables 28 and 20 on the assumption that the working capital allowance is calculated at 7.5% instead of 12.0%.

Response:

Alectra Utilities understands this to be a request to recalculate Tables 28 and 29, not Table 28 and 20. The requested recalculation, based on a working capital allowance of 7.5%, instead of 12.0%, is provided for illustrative purposes only, as the calculation is not relevant to any of the issues in the application.

Table 1 – Revision of Table 28

2016 Regulatory ROE	2016 Actuals ESM	Annual Filing EB-2015-0075
Regulatory Net Income	$20,009,623	$18,223,662
Deemed Equity	$190,522,939	$198,298,824
Return on Equity	10.502%	9.190%

% Return in Excess of 9.19%	1.312%
$ Return in Excess of 9.19%	$2,500,565
Amount Payable to Rate Payers	$1,250,282

Table 2 – Revision of Table 29

Deemed Equity Calculation	RRR 2.1.7	RRR 2.1.5.6 and ESM
Cost of Power	$610,882,333	$610,882,333
Operating Expenses	$61,631,155	$61,631,155
Total Cost of Power and Operating Expenses including Merger Costs	$672,513,487	$672,513,487
Deduct Merger Costs		($2,331,217)
Total Cost of Power and Operating Expenses excluding Merger Costs	$672,513,487	$670,182,271
Working Capital Allowance %	7.5%	7.5%
Total Working Capital Allowance	**$50,438,512**	**$50,263,670**
Fixed Assets		
Opening Balance - NBV	$415,903,516	$415,903,516
Closing Balance - NBV	$436,183,839	$436,183,839
Average NBV	**$426,043,677**	**$426,043,677**
Total Rate Base	**$476,482,189**	**$476,307,348**
Regulated Deemed Equity @ 40%	**$190,592,876**	**$190,522,939**

For the Horizon Utilities Rate Zone (“HRZ”), Alectra Utilities’ predecessor, Horizon Utilities, filed a Lead Lag study with its Custom Incentive Regulation Application (EB-2014-0002). The OEB accepted the Lead Lag Study and the working capital allowance (or factor) of 12.0%, as part of the OEB-approved Settlement Agreement. Further, Horizon Utilities’ Settlement Agreement, as agreed by the Parties and approved by the OEB, did not include changes to the working capital allowance.

BRZ-SEC-9

Reference(s): Ex. 2/2/10, p. 2, 9

Please confirm that the proposed capital expenditures in the Brampton RZ in the test year are approximately equal to the Board-approved capital expenditures in the last rebasing year. Please explain how the test year capital expenditures are thus incremental.

Response:

The proposed 2018 capital expenditure in the BRZ is $38.1MM. The OEB-approved capital expenditures in the last rebasing year were $37.9MM. Alectra Utilities confirms that these two amounts are approximately equal.

The OEB's Capital Module for ACM and ICM for the BRZ (Attachment 18 to the Application) uses the threshold formula to determine the amount of incremental capital for purposes of determining the need for additional funding of incremental capital. The 2018 proposed capital expenditures of $38.1MM less the threshold capital expenditure of $31.0MM equals $7.1MM of incremental capital.

Please see Alectra Utilities' response to PRZ-SEC-12 for further discussion of the relationship between approved cost of service test year capital expenditures and the amount in rates to fund capital spending in IRM years.

PRZ-SEC-10

Reference(s): Ex. 2/3/10, p. 2

Please explain the following sentence: "*PowerStream further leverages appropriate capital investment governance of the capital portfolio with a consistent approach to reviewing the status of expenditures, controlling the additions and removals of projects and management of expenditures approvals of project execution*."

Response:

Alectra Utilities' predecessor, PowerStream, (RZ) has an ongoing process for monitoring of the capital portfolio on monthly basis, a methodology to forecast and adjust the capital portfolio with appropriate approvals to meet emerging issues and cost review at each project stage. It uses the Copperleaf C55 platform in order to have a consistent methodology for business case development, optimization, forecasting and variance analysis.

PRZ-SEC-11

Reference(s): Ex. 2/3/10, p. 3

Please provide a chart of the actual population in the PowerStream RZ from 1950 until today.

Response:

Population from 1950s to 2016 for more populous municipalities in the PowerStream rate zone is provided in Table 1.

Table 1 – Population from 1950 to Present for Several Municipalities in PowerStream RZ Service Area

	Population (000s)					
Year	Aurora	Barrie	Markham	Richmond Hill	Vaughn	Total
1951	3.9	16.6	12.4	6.6	13.8	53.3
1971	13.6	21.2	36.7	32.4	15.9	119.8
1981	16.3	27.7	77.0	37.8	29.7	188.5
1991	29.5	38.4	153.8	80.1	111.4	413.2
1996	34.9	62.7	173.4	101.7	132.6	505.3
2001	40.2	79.2	208.6	132.0	182.0	642.0
2011	47.6	103.7	261.6	162.7	238.9	814.5
2016	53.2	128.4	301.7	185.5	288.3	957.2

Source: Statistics Canada

PRZ-SEC-12

[Ex. 2/3/10, p. 4] Please confirm that the proposed capital expenditures in the PowerStream RZ in the test year are approximately 5% less that the Board-approved capital expenditures in the last rebasing year. Please explain how the test year capital expenditures are thus incremental. Please confirm that the Applicant plans to spend $23.1 million (6.7%) less in capital in the PowerStream RZ in 2018-2020 than its last Board-approved capital spending level.

Response:

For clarity, Alectra Utilities has divided its response into three parts to deal with each of the three requests in the interrogatory.

1) Alectra Utilities' predecessor, PowerStream, last rebased its rates in 2017. Table 1 below compares the OEB-approved 2017 capital expenditures, half of which went into the 2017 rate base used to set 2017 rates, with the proposed capital expenditures for 2018.

Table 1: 2017 vs. 2018 Capital Expenditures

	2017 Approved	2018 Proposed	Change	Change %
Capital Expenditures	$ 115,800,000	$ 109,773,500	-$ 6,026,500	-5%
Depreciation	$ 52,272,173			

Alectra Utilities confirms that the proposed 2018 capital expenditures for the PRZ are 5% lower than the 2017 OEB-approved capital expenditures.

2) 2017 rates do not recover the 2017 capital expenditures of $115.8MM and therefore do not provide similar funding for additional capital expenditures in 2018. As shown in Table 1 above, 2017 rates contain depreciation of $52.3MM, which represents the annual recovery of the costs of investments in PP&E for 2017 and prior years over their estimated useful lives. One perspective is that any new capital expenditures in 2018 above the depreciation in rates are incremental capital expenditures.

Depreciation in 2017 rates of $52.3MM is the starting point in determining how much there is in rates to fund new capital investment as evidenced by the OEB's threshold formula.

In the "*Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673)",* dated September 17, 2008 ("Report"), the Board considered the question of how much capital expenditures a distributor can be reasonably expected to fund through existing rates, before additional funding may be requested. This can be found in section 2.3 - Incremental Capital Module Materiality Threshold starting on page 22. The Board concluded on page 33 that:

> *"Accordingly, the Board has determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should be distributor-specific and derived using the following formula:*

$$\textit{Threshold Value} = 1 + \left(\frac{\mathrm{RB}}{\mathrm{d}}\right) * (\mathrm{g} + \mathrm{PCI} * (1 + \mathrm{g})) + 20\%$$

Where:

RB	=	rate base included in base rates ($);
d	=	depreciation expense included in base rates ($);
g	=	distribution revenue change from load growth (%); and
PCI	=	price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

The OEB approved formula is an adoption of the formula proposed by Mr. Aiken on behalf of LPMA and Energy Probe as discussed on page 27 of the Report:

> *"Mr. Aiken, on behalf of LPMA and Energy Probe for the purposes of this part of the consultation, proposed a formulaic approach to calculate an individual threshold for each distributor. The formula incorporates both the impact of the price cap and organic growth:*

$$\frac{CAPEX}{d} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) \qquad (1)$$

Where:
RB = rate base included in base rates;
d = depreciation expense;
g = distribution revenue change based on load growth; and
PCI = price cap index (inflation less productivity factor less stretch factor).

(Mr. Aiken noted that the values for RB, d, and g, would be taken from the Board-approved base year rate decisions.)

Mr. Aiken arrived at this formula by first establishing a means of estimated the level of CAPEX that can be financed by increases in revenues due to the price cap formula and by load growth as follows:

$$CAPEX = d + RB * (g + PCI * (1 + g)) \qquad (2)$$

> *The premise of the above is that the approved base year revenue requirement covers OM&A costs and rate base costs (which include depreciation, interest on debt, return on equity and the associated taxes). Mr. Aiken noted that, similar to the other proposals, his proposal recognizes that the revenue generated under a price cap plan automatically generates more revenue for capital investment. Further, the revenue generated under a price cap plan is equal to the approved revenue requirement from the last rebasing year adjusted for the price cap index, as well as load growth."*

The OEB's formula added a dead band of 20%. The dead band is an addition to the formula by Mr. Aiken, in which he estimated the amount of revenue available from rates to fund new capital investment. The dead band indicates that the OEB will only consider incremental capital funding where the additional capital expenditures exceeds the estimated revenue available to support new capital expenditures, plus the dead band, and that no funding is available to fund the capital expenditures amount represented by the dead band.

The OEB updated this formula in the Report of the OEB: *New Policy Options for the Funding of Capital Investments: Supplemental Report January 22, 2016* (EB-2014-0219). Changes are summarized on page 3:

"The materiality threshold formula will be modified as follows:

- *A multi-year formula*
- *An annualized growth factor*
- *A dead band of 10% (down from the previous 20%)*
- *Use of the stretch factor assigned to the middle cohort (currently 0.3%) for every distributor for the determination of the materiality threshold, irrespective of the actual stretch factor at any one point in time"*

The portion of 2018 capital spending that is incremental for purposes of this proceeding is $25.9MMm as identified on Tab 10b of the OEB Capital Module Applicable to ACM and ICM for PRZ and reproduced below in Figure 1.

Figure 1: Calculation of 2018 Incremental Capital

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PowerStream Inc. - York Region and Simcoe County

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Cost of Service	*Price Cap IR*			
	Test Year 2017	Year 1 2018	Year 2 2019	Year 3 2020	Year 4 2021
Distribution System Plan CAPEX		$ 109,773,500			
Materiality Threshold		$ 83,881,705	$ 84,524,505	$ 85,182,966	$ 85,857,470
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 25,891,795	$ -	$ -	$ -

This question was also addressed in PowerStream's 2014 IRM rate application (EB-2013-0166) in response to OEB Staff-5, part (a) filed on November 29, 2013. The 2013 response discusses the reasons why the amount available in rates to fund new capital investment is significantly lower than the current level of capital expenditures. The 2013 response has been attached to this response for ease of reference.

3) From the discussion in 2) above, it can be seen that there are different ways of looking at what is the approved capital expenditures level after 2017 and its relationship to 2018-2020 capital expenditures. Alectra Utilities has prepared Table 2 below to compare the forecast expenditures for 2018-2020 based on the two different perspectives discussed in part 2 above: a) approved capital expenditures for 2017 cost of service rates and b) revenue to fund new capital expenditures plus the 10% dead band, as per the threshold formula in the ACM/ICM capital module.

Table 2: Forecast Capital Spending vs. Board-Approved Capital Spending Level for 2018-2020 ($ thousands)

Capital Expenditures (CAPEX)	2018	2019	2020	Total	
a) 2017 CAPEX Comparison					
Application Forecast	$109,773	$104,231	$110,236	$324,240	
2017 Approved CAPEX	$115,800	$115,800	$115,800	$347,400	
Difference	($6,027)	($11,569)	($5,564)	($23,160)	-6.7%
b) ACM/ICM Comparison					
Application Forecast	$109,773	$104,231	$110,236	$324,240	
ACM/ICM Threshold	$83,882	$84,525	$85,183	$253,589	
Difference	$25,891	$19,707	$25,053	$70,651	27.9%

Alectra Utilities confirms that the forecast capital spending for 2018-2020 for the PRZ of $324.2MM is $23.1MM or 6.7% less than three times the 2017 OEB-approved capital spending of $115.8MM.

Alectra Utilities identifies that the forecast capital spending for 2018-2020 for the PRZ of $324.2MM is $70.7MM or 27.9% higher than the Threshold capital expenditure in the PRZ ICM model. Table 3 uses a dead band of 0% to breakdown (c) Threshold capital expenditure amount into (e) capital expenditure funded by rates and (f) the capital expenditure amount represented by the 10% dead band.

Table 3 – Threshold Calculations - PRZ

Threshold Amounts	2018	2019	2020	Total
a) Threshold Value-10% Dead band	1.6047	1.6170	1.6296	
b) Depreciation	$ 52,272,173	$ 52,272,173	$ 52,272,173	
c) Threshold CAPEX	$ 83,881,705	$ 84,524,505	$ 85,182,966	$ 253,589,175
d) Threshold Value- 0% Dead band	1.5047	1.5170	1.5296	
e) CAPEX funded by rates	$ 78,654,488	$ 79,297,287	$ 79,955,748	$ 237,907,523
f) Dead band	$ 5,227,217	$ 5,227,217	$ 5,227,217	$ 15,681,652

Based on the OEB's threshold formula, the Threshold capital expenditure for 2018-2020 totals of $253.6MM consists of $237.9MM of capital expenditure that is funded in distribution rates and $15.7MM that is unfunded.

Board Staff Interrogatory No. 5

Ref: Manager's Summary - page 12

Ref: Application, EB-2012-0161 - Ex. B1/T.1/Sch.6, pages 30 - 33

On page 12 of the Manager's Summary, PowerStream states:

PowerStream's process is to prepare a two-year capital budget and a five year capital plan each year. The last approved capital budget was for the 2013 and 2014 calendar years. Once the 2013 and 2014 Capital Budget is approved by the Executive and the Board of Directors, the 2013 portion becomes the capital plan for 2013. The 2014 portion represents the best information at the time as to what capital work will need to be done in 2014.

As part of its annual capital planning and budgeting process in 2013, PowerStream updates the five year capital plan for 2014 to 2018. The updated five year capital plan and the 2014 portion of the 2013-2014 capital budget is then the starting point for the 2014-2015 capital budget build.

On pages 30 through 33 of Exhibit B1, Tab 1, Schedule 6 of PowerStream's last cost of service application, PowerStream provided a discussion of its forecast capital expenditures in 2014 and 2015, as compared to, 2013. On page 31 PowerStream indicated total capital expenditures of approximately $114M in 2013 and $116M in 2014. PowerStream also noted expected total capital expenditures of approximately $121M in 2015.

a) Given that PowerStream had expected relatively consistent capital expenditures in both 2013 and 2014, in its last cost of service application, please explain the changes in circumstances that have led to PowerStream filing for additional capital funding in 2014.

b) Please provide the total updated capital budget forecast for 2014, including a break-down of the discretionary work into major capital projects.

c) In its last cost of service application, PowerStream had forecast a slight increase in capital spending for 2015. Based on its current five year capital plan and two-year capital budget, is PowerStream anticipating that it will seek additional capital funding in its 2015 rate application?

Response:

a) The level of capital expenditures for 2014 that was presented in the last cost of service rate application is relatively consistent to 2013 and no new circumstances have arisen to alter the level of capital spending in 2014. However, PowerStream's capital spending has increased in recent years due in large part to the need to replace aging infrastructure. As a result, the depreciation recovered in Board-approved rates does not contain sufficient funding for new capital spending.

In the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673),* dated September 17, 2008, the Board considered the question of how much capital spending a distributor can be reasonably expected to fund through existing rates, before additional funding may be requested. This consideration can be found in section 2.3 - Incremental Capital Module Materiality Threshold starting on page 22. The Board concluded on page 33 that:

"Accordingly, the Board has determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should be distributor-specific and derived using the following formula:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB	=	rate base included in base rates ($);
d	=	depreciation expense included in base rates ($);
g	=	distribution revenue change from load growth (%); and
PCI	=	price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

That the level of required non-discretionary capital spending is not supported by current rates is clearly demonstrated by the Board's Incremental Capital Workform ("ICM Model") using the Board approved formula (Application Appendix F-1).

In PowerStream's case, the formula generates a threshold test value of 157.08% which is then applied to the 2013 approved depreciation expense of $32.9 million (M) resulting in a threshold CAPEX of $51.6M. Only non-discretionary capital additions in excess of the $51.6M are eligible for ICM funding. PowerStream has $69.8M in non-discretionary capital additions required in 2014, resulting in an Eligible Incremental Capital Amount of $18.2M.

Implicit in the Board's formula is that funding for new capital additions during the IRM period is derived from depreciation expense. This is based on the fact that depreciation represents recovery of amounts previously spent and provides funding for new capital spending.

Annual depreciation may be considered as a proxy amount for the level of annual capital additions. In a sense, annual depreciation represents an average of the annual capital additions over an extended period of time.

There are four reasons why this proxy amount is inadequate to fund the current capital requirements:

- Higher levels of capital spending and additions compared to historical levels of capital spending and additions, as PowerStream has recognized and acted on the need to replace aging infrastructure;

- Much of the 2013 depreciation expense is based on older historical cost of capital additions which are at much lower levels than 2013 and 2014 capital additions;

- There is no depreciation in rates for many of the assets being replaced, due to 100% funding by developers prior to the year 2000; and

- The change to longer useful lives under MIFRS after depreciating on shorter useful lives under CGAAP until 2010 causes a discontinuity which results in lower depreciation expense in 2013 than if PowerStream had depreciated the capital additions on the basis of MIFRS for the last 30 years of typical asset useful life.

The Board-approved capital additions for 2013 are $82.8M. This compares to capital additions of $61.9M for 2007 and $57.8M for 2006. Historically capital additions were even lower than the 2006 and 2007 levels. This increase in the level of capital additions is in part due to the need to replace aging infrastructure.

The average useful life of PowerStream's assets is 30 years. Depreciation is based on historical costs of assets that are acquired up to 60 years ago at much lower costs than current costs. In real terms the dollar amount of 2013 depreciation expense will fund the replacement of fewer assets than those that must be replaced.

The impact of lower historical levels of additions and lower historical costs on the funding in depreciation is illustrated in Example 2 below.

In many cases the assets being replaced, such as distribution assets in residential subdivisions installed prior to the year 2000, were 100 per cent funded by developers. For these assets, the cost recorded on the books, net of contributed capital, is $0 and there is no amount in depreciation for funding the replacement of these assets.

The impact of lower levels of additions and lower costs prior to 2000, due to higher levels of contributed capital, on the funding in depreciation is illustrated in Example 3 below.

PowerStream moved from CGAAP to MIFRS in 2011. PowerStream rebased under MIFRS in 2013. The change to MIFRS has also affected the amount of 2013 depreciation expense available to fund new capital additions during IRM. Under MIFRS the weighted average useful life of capital assets is 30 years. Under CGAAP the weighted average useful life was 23 years.

If PowerStream had been depreciating under MIFRS for the last 30 or more years then there would be 2013 depreciation on assets purchased between 23 and 30 years ago. Under CGAAP, the capital costs of assets, purchased between 23 and 30 years ago, are fully depreciated under CGAAP and there is no 2013 depreciation expense for these capital additions in approved rates.

The added impact, of fully depreciated assets under CGAAP that would have continued to be depreciated under MIFRS (had MIFRS been the method used for the life of the assets), on the funding in depreciation is illustrated in Example 4 below.

PowerStream has prepared the following examples in Table Staff 5-1 below to illustrate the impact of these factors.

The values used are for purposes of illustration only. For ease of illustration it has been assumed that PowerStream has only one type of asset with a useful life of 30 years and full year depreciation has been used; these assumptions are not expected to have a material impact on the results. Thirty years has been chosen as this is the average useful life under MIFRS of

PowerStream's assets. Depreciation expense has been calculated by amortizing the cost of the additions over the average life of 30 years.

Example 1 assumes the 2013 level of capital additions of $82.8M has been constant over the last 30 years.

In Example 1, the 2013 depreciation expense would be $82.8M. If this amount had been used to set 2013 rates it would provide funding of $82.8M for capital additions in 2014.

Note that PowerStream's approved rates contain only $32.8M in depreciation expense and not the $82.8M required to fund 2014 capital additions at the same level as 2013 capital additions.

Example 2 has the same level of capital additions in 2013 of $82.8M but this level of spending is the result of 3.5% year over year increases in costs due to inflation and growth.

In Example 2, the 2013 depreciation expense would be $51.8M, based on the lower average cost of capital additions of $51.8M over 30 years. If this amount had been used to set 2013 rates it would provide funding of $51.8M for capital additions in 2014.

Example 3 uses the capital additions in Example 2 and reduces the capital additions prior to the year 2000 by 30% to illustrative the effect of the fact that many assets were fully funded by developers during that period.

In Example 3, the 2013 depreciation expense would be $45.2M, based on the lower average cost of capital additions over 30 years of $45.2M which includes the impact of fully contributed assets prior to the year 2000. If this amount had been used to set 2013 rates it would provide funding of $45.2M for capital additions in 2014.

Example 4 uses the capital additions in Example 3 and removes the depreciation on assets added in 1984 through 1990. Based on an average asset life of 23 years under CGAAP, these assets would have been fully depreciated in 2013 and not included in the depreciation expense for 2013.

In Example 4, the 2013 depreciation expense would be $39.8M, based on the lower average cost of capital additions of $45.2M. Depreciation expense in this case is less than the average capital additions due to assets fully depreciated under the shorter useful life under CGAAP. If this amount had been used to set 2013 rates, it would provide funding of $39.8M for capital additions in 2014.

These examples clearly demonstrate how these factors result in much lower depreciation in rates than what is required to fund 2014 capital additions.

Example 4 is the scenario that most closely reflects PowerStream's current circumstances. Although the numbers are only representative they clearly illustrate the short-fall in funding capital additions in 2014 from depreciation. It also illustrates that the assumption that the approval of $82.8M of capital additions in 2013 rates provides adequate funding for a similar level of 2014 capital additions is invalid.

Table Staff 5-1: Depreciation Funding Illustrative Examples ($000)

	Example 1: Constant Level of Additions		Example 2: Increasing Level of Additions		Example 3: Pre 2000 100% Contribution		Example 4: CGAAP shorter life	
Year	Capital Additions	2013 Depreciation Expense	Capital Additions	2013 Depreciation Expense	Capital Additions	2013 Depreciation Expense	Capital Additions	2013 Depreciation Expense
1984	$ 82,777	$ 2,759	$ 29,458	$ 982	$ 20,621	$ 687	$ 20,621	
1985	$ 82,777	$ 2,759	$ 30,526	$ 1,018	$ 21,368	$ 712	$ 21,368	
1986	$ 82,777	$ 2,759	$ 31,633	$ 1,054	$ 22,143	$ 738	$ 22,143	
1987	$ 82,777	$ 2,759	$ 32,781	$ 1,093	$ 22,947	$ 765	$ 22,947	
1988	$ 82,777	$ 2,759	$ 33,970	$ 1,132	$ 23,779	$ 793	$ 23,779	
1989	$ 82,777	$ 2,759	$ 35,202	$ 1,173	$ 24,641	$ 821	$ 24,641	
1990	$ 82,777	$ 2,759	$ 36,479	$ 1,216	$ 25,535	$ 851	$ 25,535	
1991	$ 82,777	$ 2,759	$ 37,802	$ 1,260	$ 26,461	$ 882	$ 26,461	$ 882
1992	$ 82,777	$ 2,759	$ 39,173	$ 1,306	$ 27,421	$ 914	$ 27,421	$ 914
1993	$ 82,777	$ 2,759	$ 40,593	$ 1,353	$ 28,415	$ 947	$ 28,415	$ 947
1994	$ 82,777	$ 2,759	$ 42,066	$ 1,402	$ 29,446	$ 982	$ 29,446	$ 982
1995	$ 82,777	$ 2,759	$ 43,591	$ 1,453	$ 30,514	$ 1,017	$ 30,514	$ 1,017
1996	$ 82,777	$ 2,759	$ 45,172	$ 1,506	$ 31,621	$ 1,054	$ 31,621	$ 1,054
1997	$ 82,777	$ 2,759	$ 46,811	$ 1,560	$ 32,768	$ 1,092	$ 32,768	$ 1,092
1998	$ 82,777	$ 2,759	$ 48,509	$ 1,617	$ 33,956	$ 1,132	$ 33,956	$ 1,132
1999	$ 82,777	$ 2,759	$ 50,268	$ 1,676	$ 35,188	$ 1,173	$ 35,188	$ 1,173
2000	$ 82,777	$ 2,759	$ 52,091	$ 1,736	$ 41,673	$ 1,389	$ 41,673	$ 1,389
2001	$ 82,777	$ 2,759	$ 53,981	$ 1,799	$ 53,981	$ 1,799	$ 53,981	$ 1,799
2002	$ 82,777	$ 2,759	$ 55,938	$ 1,865	$ 55,938	$ 1,865	$ 55,938	$ 1,865
2003	$ 82,777	$ 2,759	$ 57,967	$ 1,932	$ 57,967	$ 1,932	$ 57,967	$ 1,932
2004	$ 82,777	$ 2,759	$ 60,070	$ 2,002	$ 60,070	$ 2,002	$ 60,070	$ 2,002
2005	$ 82,777	$ 2,759	$ 62,248	$ 2,075	$ 62,248	$ 2,075	$ 62,248	$ 2,075
2006	$ 82,777	$ 2,759	$ 64,506	$ 2,150	$ 64,506	$ 2,150	$ 64,506	$ 2,150
2007	$ 82,777	$ 2,759	$ 66,846	$ 2,228	$ 66,846	$ 2,228	$ 66,846	$ 2,228
2008	$ 82,777	$ 2,759	$ 69,270	$ 2,309	$ 69,270	$ 2,309	$ 69,270	$ 2,309
2009	$ 82,777	$ 2,759	$ 71,783	$ 2,393	$ 71,783	$ 2,393	$ 71,783	$ 2,393
2010	$ 82,777	$ 2,759	$ 74,386	$ 2,480	$ 74,386	$ 2,480	$ 74,386	$ 2,480
2011	$ 82,777	$ 2,759	$ 77,084	$ 2,569	$ 77,084	$ 2,569	$ 77,084	$ 2,569
2012	$ 82,777	$ 2,759	$ 79,880	$ 2,663	$ 79,880	$ 2,663	$ 79,880	$ 2,663
2013	$ 82,777	$ 2,759	$ 82,777	$ 2,759	$ 82,777	$ 2,759	$ 82,777	$ 2,759
2013 Depreciation Expense		$ 82,777		$ 51,762		$ 45,174		$ 39,807
Average additions		$ 82,777	$ 51,762		$ 45,174		$ 45,174	

PRZ-SEC-13

Reference(s): Ex. 2/3/10, p. 11

Please explain how the acceleration of the CIS project into 2017 is not merger-related spending. Please calculate, on a cost of service revenue requirement basis, the impact of that project in each of 2017, 2018, and 2019, including all tax shelter impacts.

Response:

Alectra Utilities has divided the question into two parts in order to address the interrogatory.

1) For the first part of this question, please see Alectra Utilities response to PRZ-AMPCO-4 a).

2) The second part of this question is hypothetical and not relevant to the 2018 ICM request. The 2018 ICM request for the PRZ does not contain any amounts for the upgrade to the current version of the CC&B CIS software, nor is the resulting ICM funding affected by the version upgrade in 2017. Alectra Utilities has not provided a calculation.

PRZ-SEC-14

Reference(s): Ex. 2/3/10, p. 23

Please provide information on the outage minutes caused by the ice storm on a per km of line or other unitized basis, e.g. % of underground line in the system compared to percentage of outage minutes as a result of the storm.

Response:

Typical feeder configuration consists of sections of underground and overhead portions and it is not possible to provide the requested information. However, the impact of the Ice Storm on rear lot grids, which are overhead, has been analyzed. The ice storm of December 2013 caused a total of 178,831,919 Customer Minutes of Interruption (“CMI”). The rear lot grids accounted for 29,831,573 CMI, which is 16.68% of the total CMI during the ice storm.

ERZ-SEC-15

Reference(s): Ex. 2/4/11, p. 9

Please provide a chart of the actual population in the Enersource RZ from 1950 until today.

Response:

Population from 1950s to 2016 for the Enersource rate zone is provided in Table 1.

Table 1 – Population from 1950 to Present for Enersource RZ Service Area

Year	Mississauga Population (000s)
1951	33.3
1961	74.9
1971	172.4
1981	315.1
1991	463.4
1996	544.4
2001	613.0
2011	668.6
2016	713.4

Sources: Dieterrman, F. Mississauga: First 10,000 Years (2002); Riendeau, R.E. Mississauga: An Illustrated History (1985); Statistics Canada.

ERZ-SEC-16

Reference(s): Ex. 2/4/11, p. 10

Please provide the report from Kinectrics referred to.

Response:

Alectra Utilities has provided the most recent Kinectrics Report as ERZ-SEC-16_Attach 1_Kinectrics Report.

ENERSOURCE HYDRO MISSISSAUGA
2015 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418951-RA-R00

August 8, 2016

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Toronto, ON
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ENERSOURCE HYDRO MISSISSAUGA
2015 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418951-RA-R00

August 8, 2016

Prepared by:

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Dated: August 8, 2016

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Revision History

Revision Number	Date	Comments	Approved
R00	August 8, 2016	Final Draft	Yury Tsimerg

EXECUTIVE SUMMARY

In 2011 Enersource Hydro Mississauga (Enersource) determined a need to perform a condition assessment of its key distribution assets. Enersource selected and engaged Kinectrics Inc. (Kinectrics) to perform the Asset Condition Assessment (ACA). Subsequent assessments were conducted in 2011, 2013, and 2014. This report presents the results for the fifth, 2015, ACA.

The asset groups included in the 2015 ACA are as follows: substation transformers, circuit breakers, distribution transformers (pole mounted, pad mounted, and vault), pad mounted switchgears, overhead line switches, underground cables, and poles. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

It was found that underground cables have the highest percentages in poor to very poor condition. Wood poles, vault transformers, and pad mounted switchgear also have large quantities that are classified as poor or very poor.

In terms flagged for action, it was found that over 9% of main feeder underground cables and nearly 15% of distribution underground cables are currently flagged for action. Furthermore, within the next 10 years, more than 40% of the underground cable population should be addressed.

Also of significance is that presently, 10% of wood poles have been flagged for action. This includes poles that require action because of the insulation used. In the next 10 years 35% of all wood poles will need to be addressed.

In the past year Enersource has made improvements with respect to inspection programs and condition data collection. Availability of inspection information was improved for many assets, and most notably for breakers, switchgear, and poles. Enersource should continue with the improvements made inspections and gathering data.

There is still limited data for overhead switches and wood poles. It is recommended that additional data be gathered for these asset groups. It is further recommend that Enersource consider collecting corrective maintenance records for all asset categories. Corrective maintenance history would be useful in highlighting units or components that have been historically problematic or aging at an accelerated rate.

The results presented in this study are based solely on asset condition as determined by available data. Note that there are numerous other considerations that may influence Enersource's planning process. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

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I INTRODUCTION

Enersource Hydro Mississauga (Enersource) recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. An assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan. This undertaking spans several years and thus allows Enersource to monitor the trend in asset condition changes and to incrementally improve its assessment process and asset management practices.

In early 2011, Enersource selected and engaged Kinectrics Inc. (Kinectrics) to perform the first ACA on Enersource's key distribution assets. This assessment covered Enersource's asset population as of the end of 2010. Second, third, and fourth assessments were conducted for Enersource's 2011, 2013, and 2014 populations respectively. This report presents results for the fourth year assessment and is based on the available data as of the end of 2015.

I.1 Objective and Scope of Work

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
    - In Service
    - Spares
- Substation Circuit Breakers
    - High Voltage
    - Low Voltage
- Pole Mounted Transformers
- Pad Mounted Transformers
    - 1 Phase
    - 3 Phase
- Vault Transformers
- Pad Mounted Switchgears
- Overhead Line Switches
    - 44 kV
    - 27.6 kV
    - Inline
    - Motorized
- Underground Cables
    - Main Feeder
    - Distribution
- Poles
    - Wood
    - Concrete

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following are included:
    - Health Index formulation
    - Age distribution
    - Health Index distribution
    - Condition-based Flagged For Action Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis
- An audit describing the key changes between 2014 and 2015

II ASSET CONDITION ASSESSMENT METHODOLOGY

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weights, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS_m = \frac{\sum_{n=1}^{\forall n} \beta_n (SCPS_n \times WSCP_n) \times DR_n}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)} \times DR_m$$

Equation 2

CPS	Condition Parameter (CP) Score, 0-4
WCP	Weight of Condition Parameter
α_m / β_n parameter	Data availability coefficient for condition/sub-condition
	(1 if input data available; 0 if not available)
SCPS	Sub-Condition Parameter (SCP) Score, 0-4
WSCP	Weight of Sub-Condition Parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. In the Kinectrics methodology, a condition criteria scoring system of 0 through 4 is used. A score of 0 is the “worst” possible score; a score of 4 is the “best” score. I.e. $CPS_{max} = SCPS_{max} = 4$.

Note: From the formula, it can be seen that each parameter (condition or sub-condition) will have the following properties:

1. Weight
2. Availability coefficient (1 if asset has data for such parameter available; 0 otherwise)
3. Score (real value from 0 through 4)
4. Multiplier (real value)

II.1.1 Health Index Results

As stated previously, an asset’s Health Index is given as a percentage, with 100% representing “as new” condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 **Condition Based Flagged for Action Plan**

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$\mathrm{f} = \gamma e^{\beta t}$$ **Equation 3**

f	= failure rate per unit time
t	= time
γ, β	= constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

Equation 4

$$\mathrm{f(t)} = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= age (years)
α, β	= constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

Equation 5

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

P_f	= cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} = 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

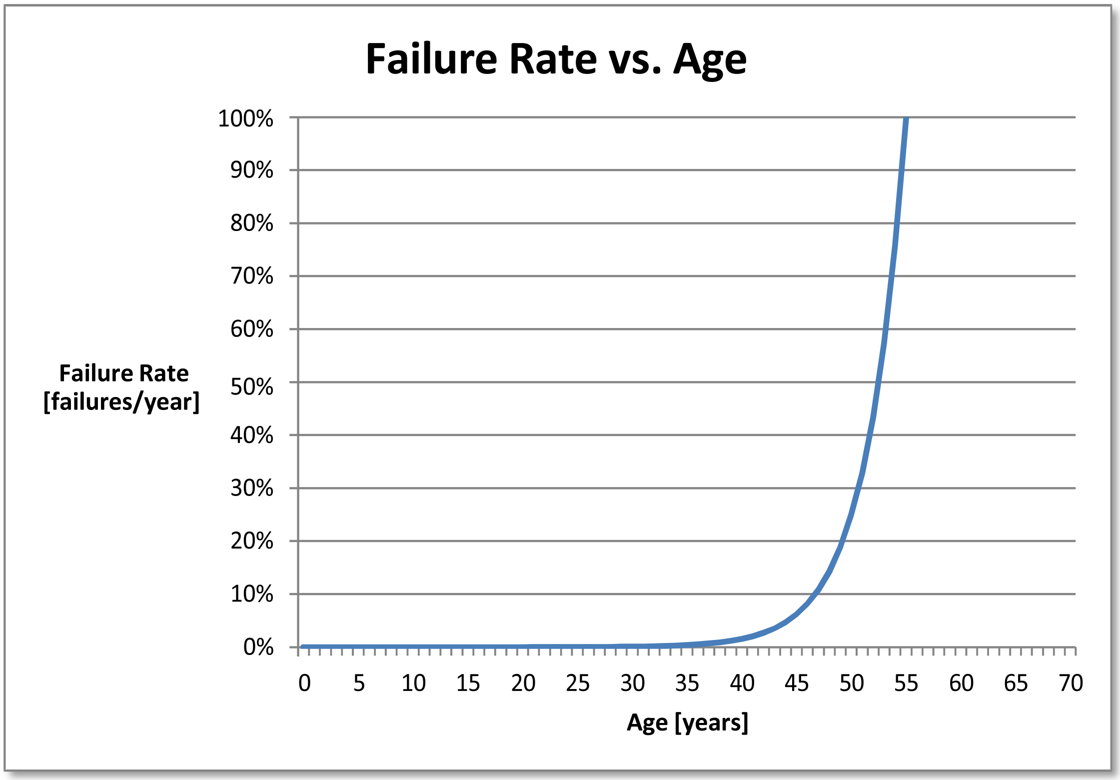


Figure 0-1 Failure Rate vs. Age

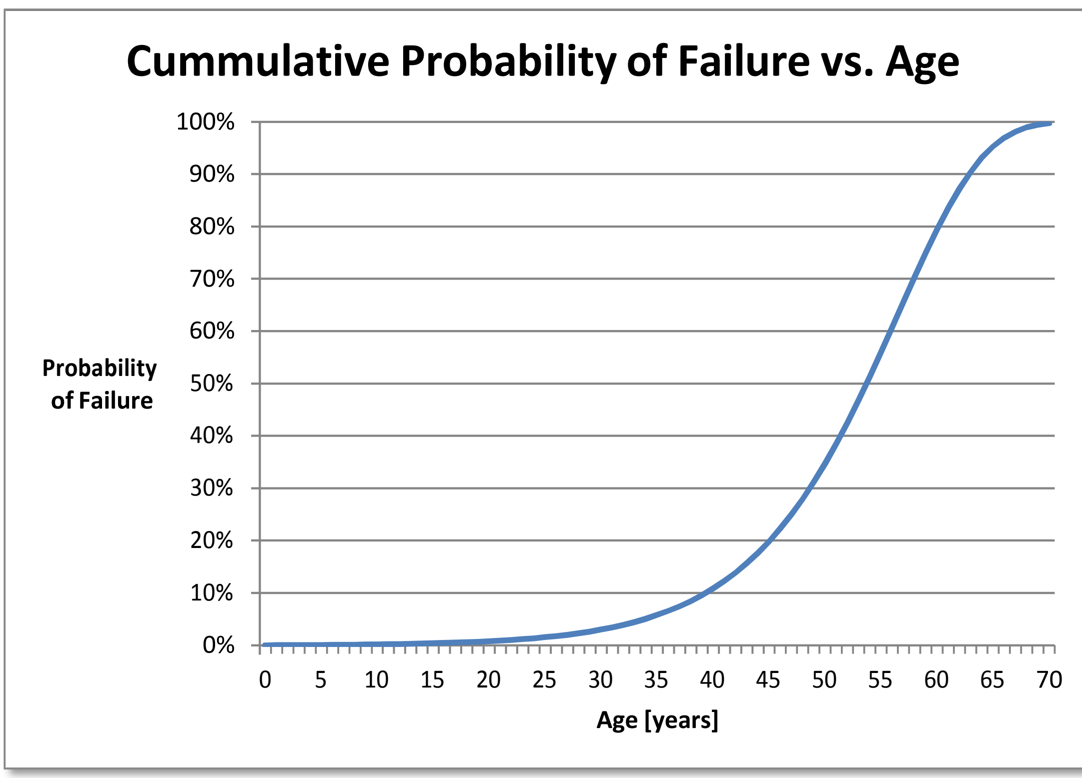


Figure 0-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\{3(t-a)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are $f_5 = 0.02$, $f_{10} = 0.05$, $f_{20} = 0.1$ failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

The Levelized Flagged for Action plan smooths or levelizes the peaks and valleys of the flagged for action plan.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

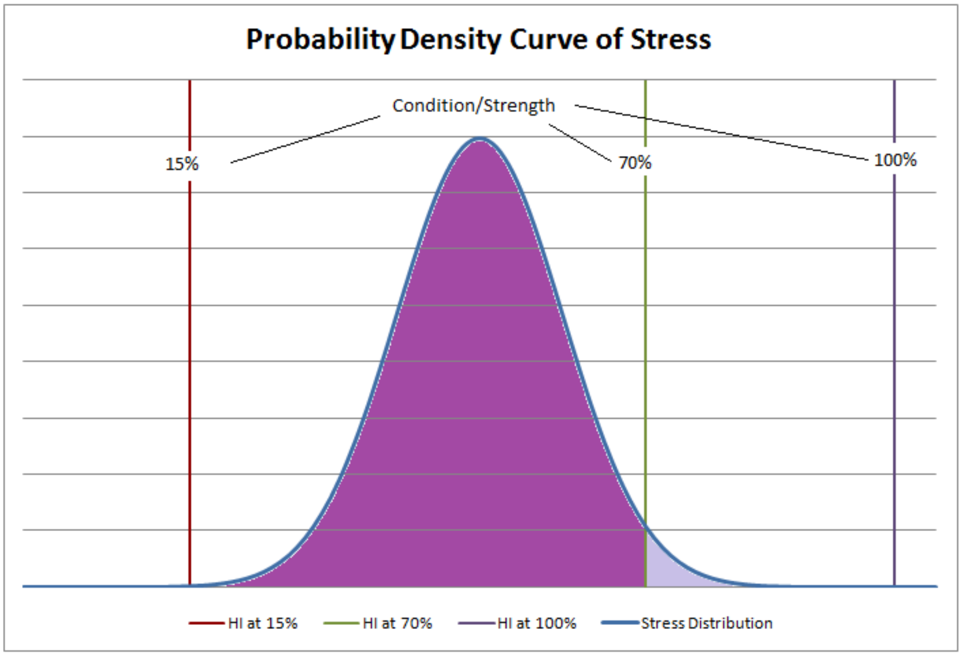


Figure 0-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

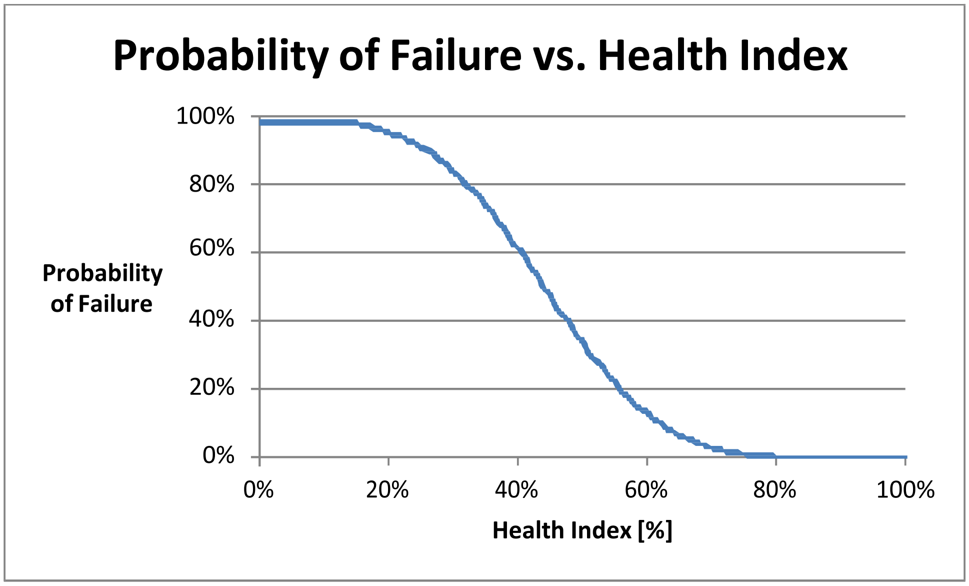


Figure 0--4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.43. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action. In this case, if the unit with the criticality value of 1.43 has a POF = 70%, its risk will be 1.43*0.7 = 1 and it will be flagged for action.

II.3 Data Assessment

The condition data used in this study were provided by Enersource and included the following:

- Test Results (e.g. Oil Quality, DGA)
- Inspection Records
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\ m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n \times WCFn}{\sum_{n=1}^{\forall n} (WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	**Name**		**n**	**Name**		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$DAI_{CP1} = (1*1) / (1) = 1$
$DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545$
$DAI_{CP3} = (0*1) / (1) = 0$

$$DAI = (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3)$$
$$= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3)$$
$$= 35\%$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on Enersource's available data. There are additional parameters or tests that Enersource may not collect but that are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	+++
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	++
Low	Helpful data; least indicative of asset deterioration	+

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulas.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for “Tank Corrosion” on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	++	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table III-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and average age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure III-5. Note that the Health Index distribution percentages are based on the asset group's sample size.

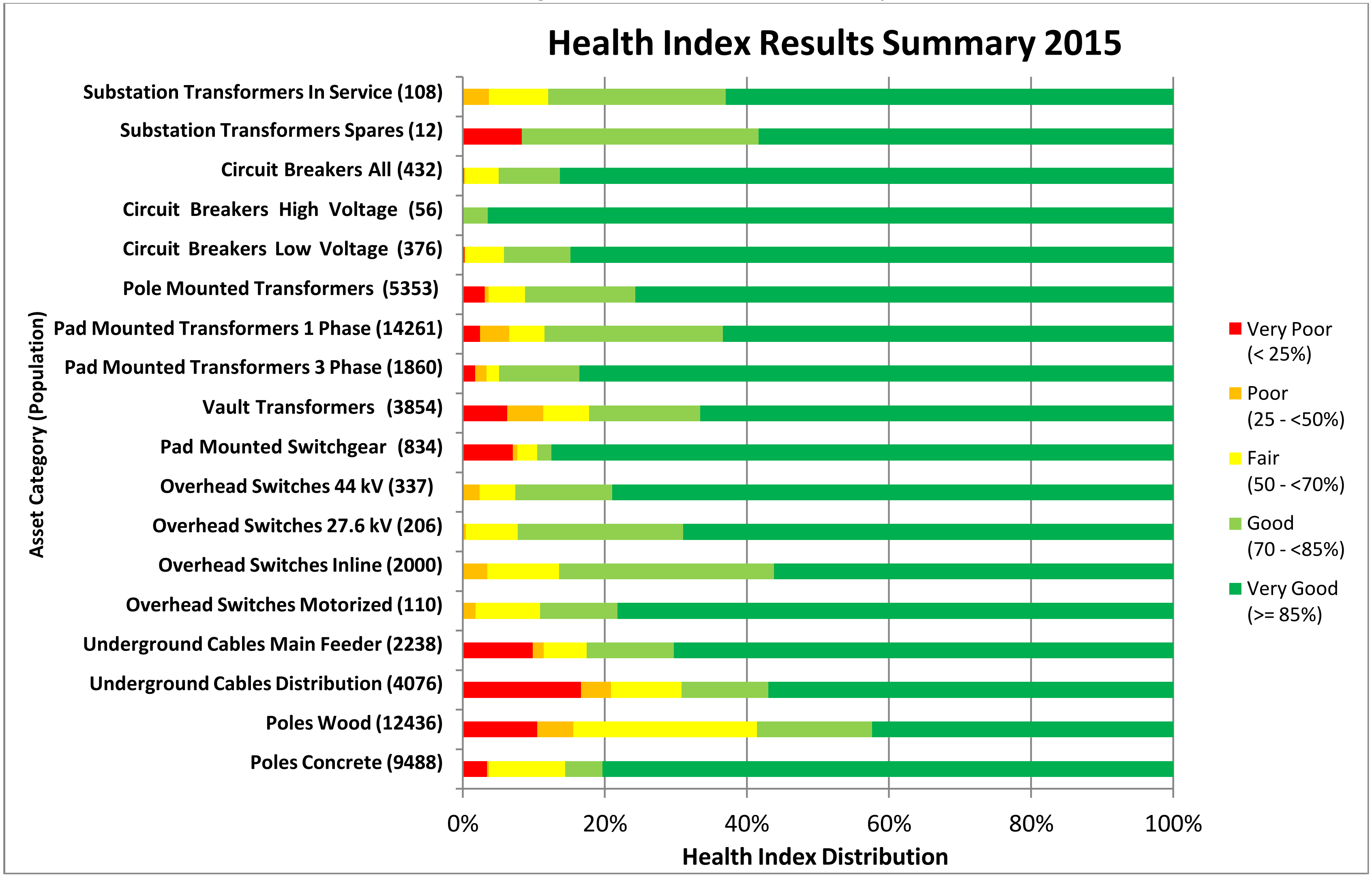
It can be seen from the results that Underground Cables category was, on average as an asset group, in the worst condition. Approximately 12% of main feeder and 21% of distribution cables were classified as "poor" or "very poor".

Another group of concern is Wood Poles where 16% are in "poor" or "very poor" condition. It should also be noted that 11% of Vault Transformers are classified as "poor" or "very poor" and that 8% of Switchgear are in "poor" or "very poor" condition.

Table III-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	Average Age	Average DAI
Substation Transformers	In Service	108	108	87%	0%	4%	8%	25%	63%	23	87%
	Spares	12	12	82%	8%	0%	0%	33%	58%	33	45%
Circuit Breakers	All	432	432	93%	< 1%	0%	5%	9%	86%	22	94%
	High Voltage	56	56	96%	0%	0%	0%	4%	96%	23	98%
	Low Voltage	376	376	93%	< 1%	0%	6%	9%	85%	21	94%
Pole Mounted Transformers		5353	5353	90%	3%	< 1%	5%	16%	76%	20	77%
Pad Mounted Transformers	1 Phase	14261	14261	86%	2%	4%	5%	25%	63%	21	70%
	3 Phase	1860	1860	93%	2%	2%	2%	11%	84%	16	68%
Vault Transformers		3854	3854	84%	6%	5%	6%	16%	67%	27	88%
Pad Mounted Switchgear		834	834	88%	7%	< 1%	3%	2%	88%	15	84%
Overhead Switches	44 kV	337	337	89%	0%	2%	5%	14%	79%	21	57%
	27.6 kV	206	206	87%	0%	< 1%	7%	23%	69%	19	57%
	Inline	2000	2000	82%	0%	4%	10%	30%	56%	18	57%
	Motorized	110	110	90%	0%	2%	9%	11%	78%	15	55%
Underground Cables *Note that results are given in terms of conductor-km	Main Feeder	2238	2238	82%	10%	2%	6%	12%	70%	18	100%
	Distribution	4076	4076	75%	17%	4%	10%	12%	57%	21	100%
Poles	Wood	12436	12436	73%	11%	5%	26%	16%	42%	27	47%
	Concrete	9488	9488	91%	3%	< 1%	11%	5%	80%	20	88%

Figure III-5 Health Index Results Summary



III.2 **Condition-Based Flagged for Action Plan**

It is evident from Table III-2, Table III-3, and Figure III-6 that there may be significantly larger quantities of assets flagged for action in the first year than in subsequent years. This is generally the case when there is a large quantity of assets that are at or near the end of their service lives. Because such assets would have high probabilities of failure, large quantities will be flagged for intervention in the first year. Since the assessment methodology assumes that all units flagged for action are replaced, the quantities flagged for action in year 2 or later may be significantly smaller than that of the first year. In reality, only some of the units flagged for action in the first year will be dealt while the remaining units will be addressed in subsequent years (e.g. levelized action plan). Figure III-8 shows the comparison between the levelized and un-levelized plan.

At present, over 9% of main feeder underground cables and nearly 15% of distribution underground cables were flagged for action. Within the next 10 years, over 40% of underground cable population is flagged for action.

Presently, nearly 10% of wood poles are flagged for action. A significant number of the pad mounted switchgear population, 6%, has been flagged for action today. As well, over 5% of vault transformers require attention. This includes transformers that contain PCBs.

It is important to note that the Flagged for Action plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. While this condition-based Flagged for Action Plan can be used as a guide or input to Enersource's Distribution System Plan, it is not expected that it be followed directly or as the final deciding factor in making sustainment capital decisions. There are numerous other factors and considerations that will influence Enersource's Asset Management decisions, such as obsolescence, system expansion, regulatory requirements, municipal demands, etc.

Table III-2 Year 1 Flagged for Action Plan

Asset Category		10 Year Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
Substation Transformers	In Service	3	2.8%	9	8.3%	3	2.8%	9	8.3%	proactive
	Spares	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Circuit Breakers	High Voltage	0	0.0%	1	1.8%	0	0.0%	1	1.8%	proactive
	Low Voltage	1	0.3%	1	0.3%	1	0.3%	1	0.3%	proactive
Pole Mounted Transformers		139	2.6%	307	5.7%	29	0.5%	318	5.9%	reactive
Pad Mounted Transformers	1 Phase	294	2.1%	847	5.9%	77	0.5%	810	5.7%	reactive
	3 Phase	35	1.9%	103	5.5%	10	0.5%	124	6.7%	reactive
Vault Transformers		205	5.3%	412	10.7%	39	1.0%	364	9.4%	reactive
Pad Mounted Switchgear		51	6.1%	84	10.1%	8	1.0%	78	9.4%	reactive
Overhead Switches	44 kV	1	0.3%	28	8.3%	3	0.9%	34	10.1%	reactive
	27.6 kV	1	0.5%	20	9.7%	2	1.0%	29	14.1%	reactive
	Inline	38	1.9%	403	20.2%	36	1.8%	452	22.6%	reactive
	Motorized	0	0.0%	9	8.2%	1	0.9%	12	10.9%	reactive
Underground Cables *Note that results are given in terms of conductor-km	Main Feeder	203	9.1%	700	31.3%	67	3.0%	596	26.6%	reactive
	Distribution	605	14.8%	1822	44.7%	176	4.3%	1495	36.7%	reactive
Poles	Wood	1205	9.7%	4401	35.4%	422	3.4%	4381	35.2%	proactive
	Concrete	188	2.0%	781	8.2%	72	0.8%	783	8.3%	proactive

Table III-3 Ten Year Flagged for Action Plan

Replacement Year	Type (L = Levelized)	Asset Category																
		Substation Transformers		Circuit Breakers		Pole Mounted Transformers	Pad Mounted Transformers		Vault Transformers	Pad Mounted Switchgear	Overhead Switches				Underground Cables *Note that results are given in terms of conductor-km		Poles	
		In Service	Spares	HV	LV		1 Phase	3 Phase			44 kV	27.6 kV	Inline	Motorized	Main Feeder	Distribution	Wood	Concrete
0		3	N/A	0	1	139	294	35	205	51	1	1	38	0	203	605	1205	188
	L	3	N/A	0	1	29	77	10	39	8	3	2	36	1	67	176	422	72
1		0	N/A	0	0	34	73	3	46	10	1	1	37	0	70	207	658	118
	L	0	N/A	0	0	29	77	10	39	8	3	2	36	1	67	176	422	72
2		0	N/A	0	0	10	44	5	19	3	1	1	38	0	59	171	389	72
	L	0	N/A	0	0	29	77	10	39	8	3	2	36	1	67	176	422	72
3		1	N/A	0	0	8	30	8	12	3	1	1	38	0	55	149	293	53
	L	1	N/A	0	0	29	75	10	36	8	3	2	36	1	67	176	417	72
4		0	N/A	1	0	9	37	8	14	1	3	2	37	0	52	134	271	44
	L	0	N/A	1	0	29	75	10	36	8	3	2	36	1	56	143	417	72
5		0	N/A	0	0	15	43	7	17	3	4	1	38	1	51	122	267	43
	L	1	N/A	0	0	28	72	12	29	6	3	3	45	1	46	109	407	72
7		2	N/A	0	0	18	58	6	18	2	3	3	31	2	47	100	268	50
	L	2	N/A	0	0	28	72	12	29	6	3	3	45	1	46	109	407	72
8		1	N/A	0	0	19	66	7	21	2	4	2	34	1	43	88	265	52
	L	1	N/A	0	0	28	70	12	27	6	3	3	45	1	46	109	350	69
9		1	N/A	0	0	18	74	8	21	3	4	3	39	2	38	74	265	56
	L	1	N/A	0	0	28	70	12	27	6	3	3	45	1	39	89	350	69
10		0	N/A	0	0	21	77	9	22	4	3	3	41	1	33	61	254	60
	L	0	N/A	0	0	33	70	14	27	8	4	4	47	2	39	89	350	69

Figure III-6 Ten Year Flagged for Action Plan

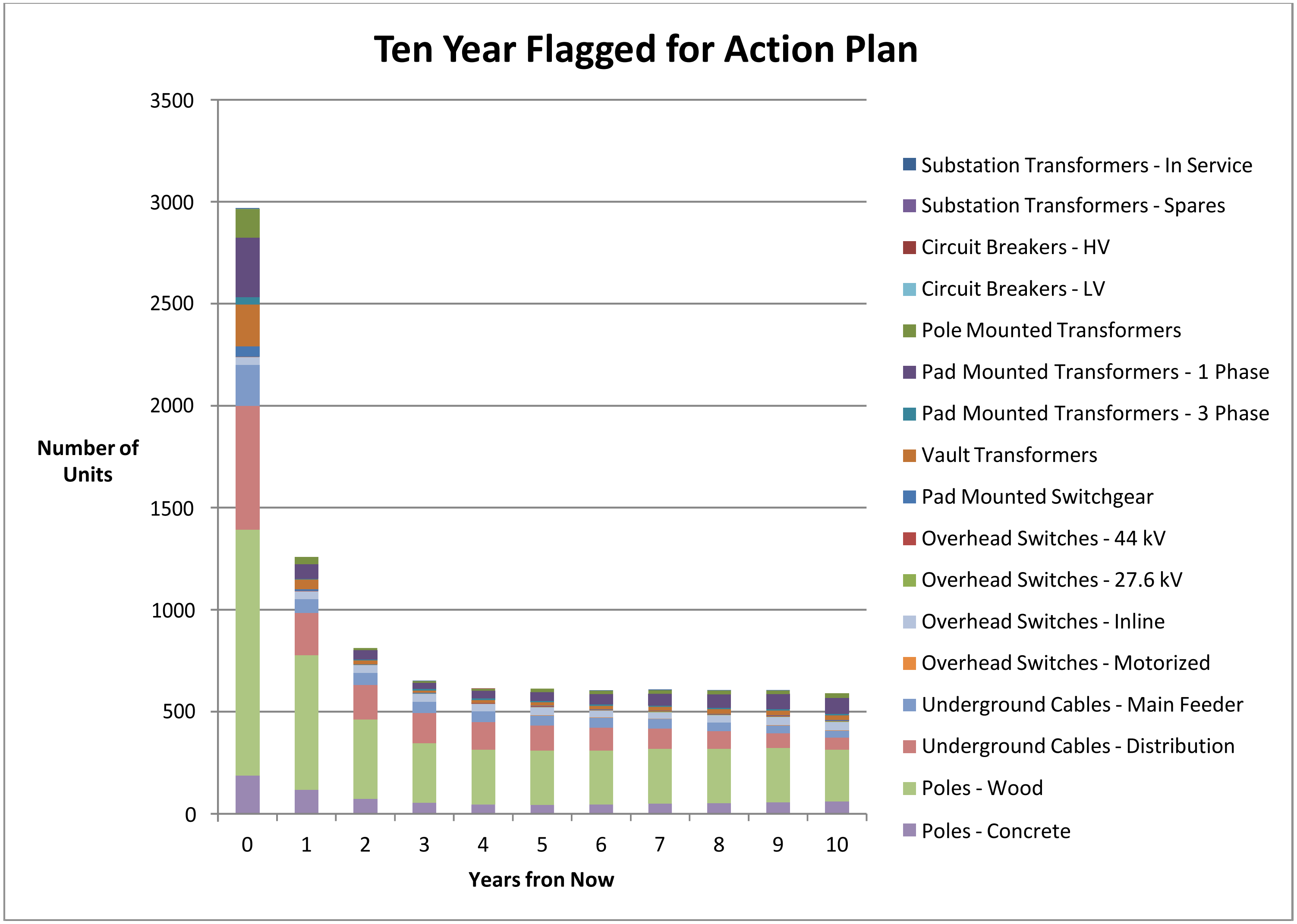
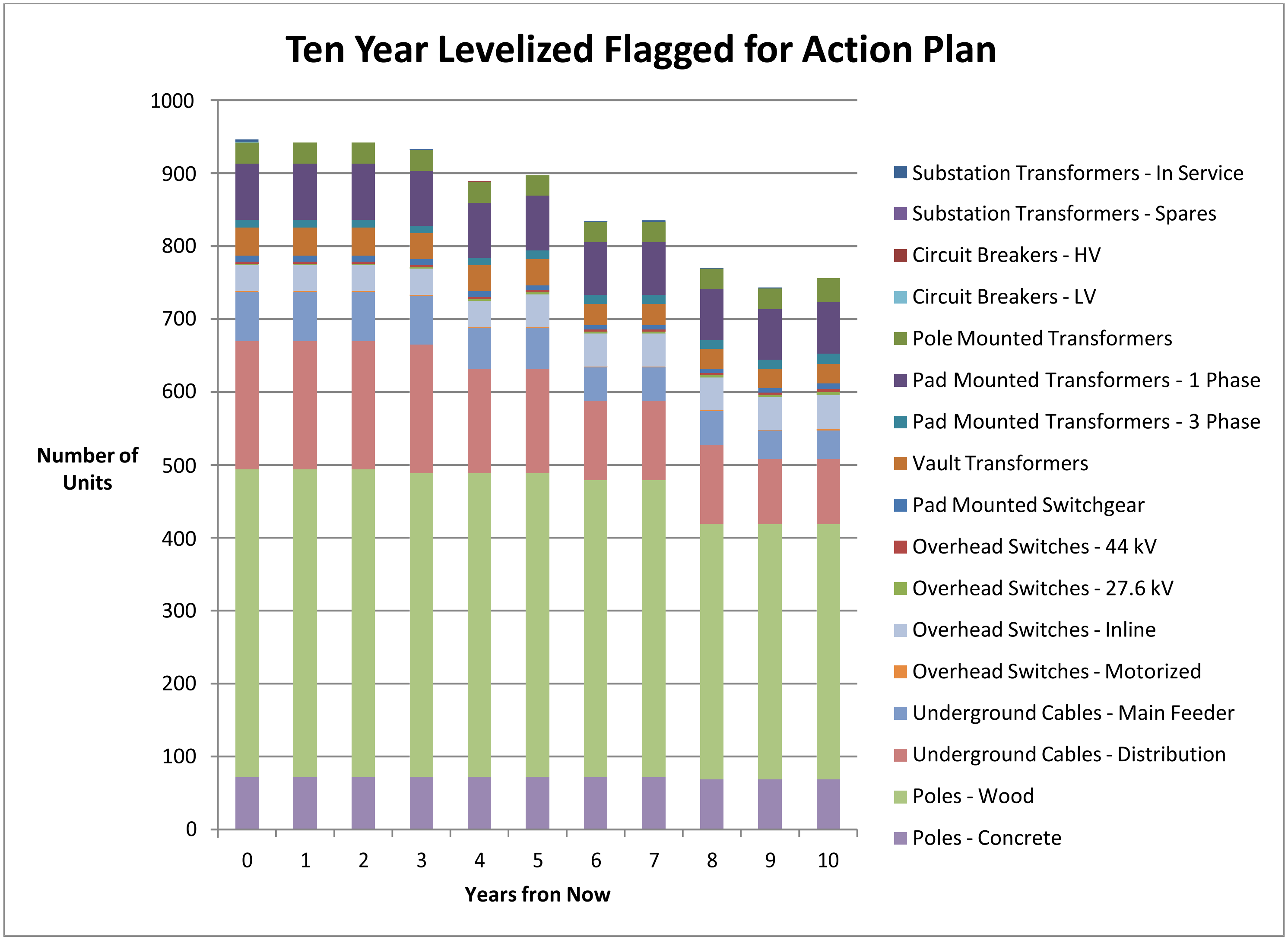


Figure III-7 Ten Year Levelized Flagged for Action Plan



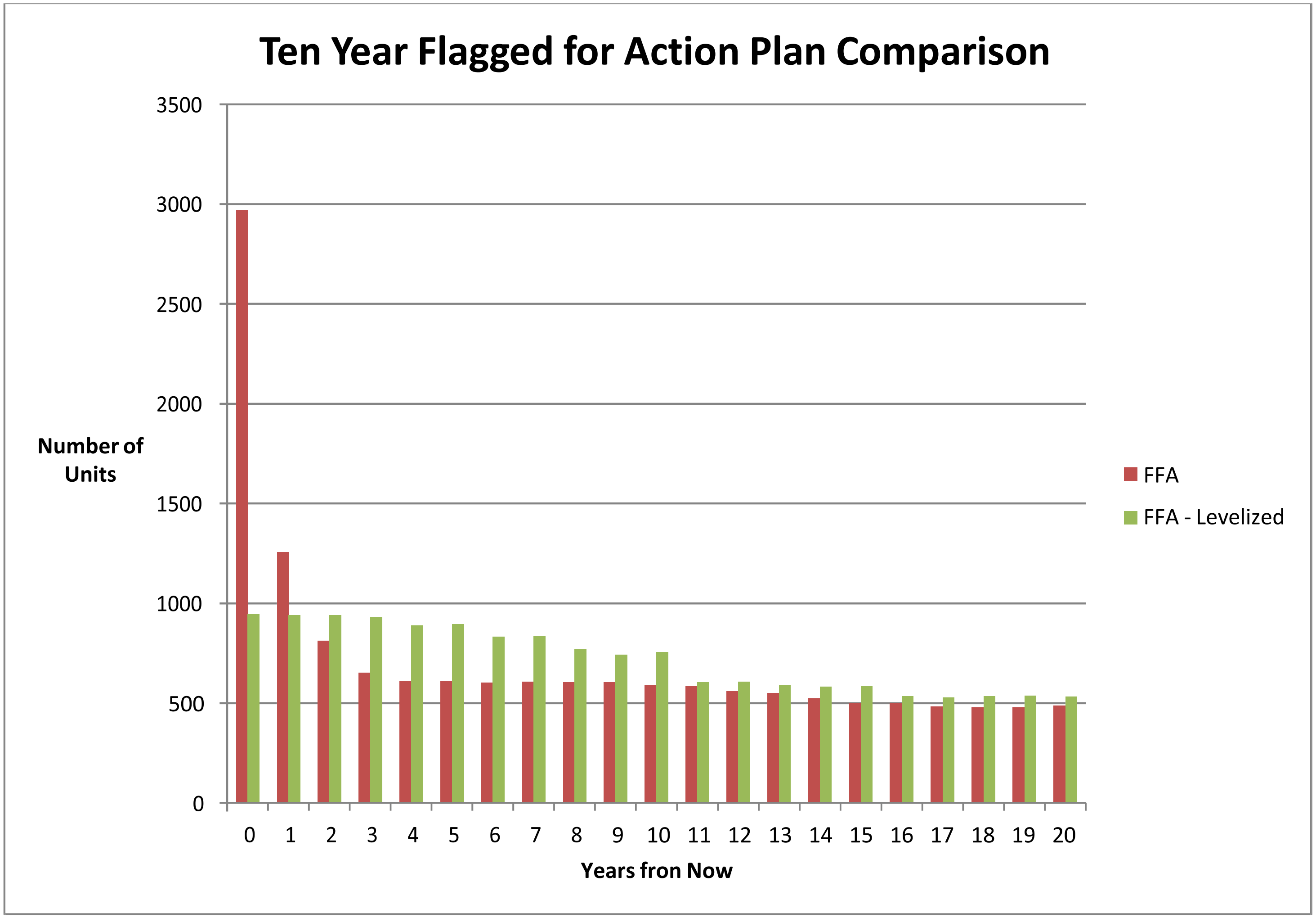


Figure III-8 Ten Year and Ten Year Levelized Flagged for Action Plans Comparison

III.3 Data Assessment Results

Data assessment includes a review of the data availability indicator (DAI) of each unit, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of data currently available in for its respective asset category. Data gaps are items that are indicators of asset degradation, but are currently not collected or available for any unit within an asset category. The more minimal the data gaps, the higher the quality of the Health Index formula.

Most of the required condition data for Substation Transformers was available. At 87%, the average of DAI of this group was slightly better than in the previous year (84% in 2014). There has also been an improvement in the collection of inspection data. Nearly 85% of the population had inspection data in 2015 (an improvement over the 76% of units with inspection in 2014).

Data for Circuit Breakers included age, contact resistance, and inspection results. The average DAI for this asset group improved significantly from 71% last year to 94% this year. This is a result of an improvement in the collection of inspection data, i.e. all breakers had inspection data in 2015. In 2014 timing tests were identified as a data gap. Enersource does perform timing specification tests where the overall trip time of a breaker is tested as part of the breaker maintenance cycle. This information will be incorporated in future assessments.

The average DAI for Pole Mounted transformers increased from 75% in 2014 to 77% in 2015. A significant improvement for this asset category is the collection and incorporation of loading data into the Health Index calculation.

The average DAI of Pad Mounted Transformers has dropped from 89% to 70% for 1-phase and 70% to 68% for 3-phase year. This is because certain visual inspection information, namely access to the transformer and the condition of the foundation, was not available this year. Additionally, information about oil leak was limited. Significant improvements with respect to closing data gaps were, however, made. Elbow connection and loading information were collected and incorporated into the Health Index formula.

The average DAI of Vault Transformers has improved from 78% to 88% this year. Significant improvements with respect to closing data gaps were the collection and incorporation of bushing and loading information.

The average Pad Mounted Switchgear DAI improved significantly from 39% in 2014 to 89% in 2015. This is because of a significant increase in the availability of inspection information. In 2014 only half of the population had inspection records; in 2015 93% of the switchgear population was inspected.

While the DAI of Overhead Switches appeared to have increased, it should be noted that only age and an indication of whether a switch has been operated in recent years is available. Condition information, e.g. switch condition, insulator condition, and arc extinction information, have yet to be collected for this asset group.

Age data was available for Underground Cables and because age was known for all segments, the average DAI for both Main Feeder and Distribution Cables sub-categories was 100%. Enersource should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta). Such information will provide good, objective condition data as input into the Health Index.

In 2013, the assessment for both Wood and Concrete poles were based on age only. Because age was known for most poles, the 2013 DAIs for both wood and concrete poles was 100%. In 2014 Enersource launched a pole inspection program wherein visual inspection information was gathered. The Health Index formulas for wood and concrete poles were revised to include inspection data. Because less than 40% of poles were inspected, the DAI for both wood and concrete poles dropped to 55%. The only data gap for this asset category is pole strength.

The apparent decrease in DAI of wood poles is not a result of decreased data, but rather from a change in the health index formula. In 2015, Enersource made significant strides by conducting pole testing. The resulting resistograph test results were included in the formula. Since this parameter has a high weight and only 9% of the population was tested, the average DAI for this asset group is only 47% as compared to 55% from 2014. This is no cause for concern as this DAI will increase as more poles are tested. It should further be noted that over 90% of poles have been inspected. This is a vast improvement over the 40% that were inspected in 2014.

Concrete poles showed a significant increase in DAI (88% in 2015 vs. 55% in 2014). This is because of the significant increase in inspection data.

A general comment that applies to all asset categories is that Enersource should consider collecting corrective maintenance information. Although the most recent inspection records are helpful in indicating an asset's current state, it does not give insight to past problems associated with an asset. Corrective maintenance history is useful in that it will highlight units or components of units that have been historically problematic or aging at an accelerated rate.

III.4 **2014 to 2015 Audit**

This section describes the changes identified between the 2014 and 2015 ACA.

1. Asset Categories
2. Health Index Formula
3. Population and Sample Size
4. Health Index Distribution

Changes in Asset Categories

- Breakers: Sub-categorized as LV and HV breakers. Different health index formula for each category, as different data were available

Changes in Health Index Formulation

Since 2014, Enersource has made significant efforts with respect to collecting more condition data for several asset categories. Thus, for some asset categories, the Health Index formulas were changed so that the newly collected data could be included. The asset categories and changes to Health Index are described below:

- *Substation Transformers*: Minor increase in "Insulation" condition parameter weights.

- *Circuit Breakers*: Because inspections differ between high and low voltage (LV) breakers, separate Health Index formulas were used to represent their. The low voltage breaker formula has only minor modifications to weights, as compared to the 2014 breaker formula. The high voltage (HV) breaker formula includes additional parameters that are part of the HV breaker inspections (e.g. contact alignment, phase barriers).

- *Pole Mounted Transformers*: The 2015 formula has been modified to include the newly collected loading data for distribution transformers.

- *Pad Mounted Transformers*: The 2015 formula has been modified to include the condition of the enclosure, as well as the newly collected loading data for distribution transformers.

- *Vault Mounted Transformers*: The 2015 formula has been modified to include the condition of the enclosure, bushing, as well as the newly collected loading data for distribution transformers.

- *Pad Mounted Switchgear*: The 2015 formula has been modified to include additional inspection items, such as hot spot, tracking, and SF6 leaks.

- *Overhead Switches*: The 2015 formula changed from 2014 in that operations record was added.

- *Underground Cables*: No changes were made to the parameter or weights of the underground cable formula. However, the useful life assumptions, and therefore, failure curve used in the assessment of non-tree retardant, direct buried cables were adjusted. The life range used in 2014 was found to be conservative; based on the population profile these types of cables are in service longer than expected.

- *Wood Poles*: More detailed inspection items were incorporated into the 2015 formula. These include items such as shell rot, mechanical damage, cracks, and feathering. Another important parameter included in 2015 is pole strength (resistograph tests).

- *Concrete Poles*: The 2015 formula includes the condition of the concrete, as per the pole inspection.

Changes in Population and Sample Size

Table III-4 summarizes the change in population and in sample size between 2014 and 2015. A graphical representation of the population change is show Figure III-9.

Table III-4 Summary Change in Population and Sample Size

Asset		Population				Sample Size		
		Population Count 2014	Population Count 2015	Population Change by Counts	Population Change by %	% Sample Size 2014	% Sample Size 2015	Sample Size Change by %
Substation Transformers	In Service	108	108	0	0%	100%	100%	0%
	Spares	12	12	0	0%	100%	100%	0%
Circuit Breakers	All	510	432	-78	-15%	100%	100%	0%
	High Voltage	0	56					
	Low Voltage	0	376					
Pole Mounted Transformers		5346	5353	7	0%	100%	100%	0%
Pad Mounted Transformers	1 Phase	14242	14261	19	0%	100%	100%	0%
	3 Phase	1821	1860	39	2%	100%	100%	0%
Vault Transformers		3861	3854	-7	0%	100%	100%	0%
Pad Mounted Switchgear		862	834	-28	-3%	100%	100%	0%
Overhead Switches	44 kV	338	337	-1	0%	100%	100%	0%
	27.6 kV	213	206	-7	-3%	100%	100%	0%
	Inline	2002	2000	-2	0%	100%	100%	0%
	Motorized	104	110	6	6%	100%	100%	0%
Underground Cables *Note that results are given in terms of conductor-km	Main Feeder	2233	2238	5	0%	100%	100%	0%
	Distribution	4038	4076	38	1%	100%	100%	0%
Poles	Wood	12917	12436	-481	-4%	100%	100%	0%
	Concrete	8966	9488	522	6%	100%	100%	0%

For a majority of the asset classes, the change in populations remained fairly steady, within ± 5%. The asset classes that have more significant change populations in 2015 than in 2012 are as follows:

- The breaker population has decreased by 15%. This may be due to a removal of breakers in the following stations BEXHILL, BIRCHVIEW, BROMSGROVE, CLARKSON, DERRY, DERRY MINI, DIXIE, MELTON, MINEOLA, ORCHARD HEIGHTS, PARKWEST, REVUS, REXDALE, and YORK.
- New motorized overhead line switches were installed under the new automation orientation program, resulting in a 6% increase.
- New concrete pole installations and replacement of some wood poles with concrete poles resulted in a 6% population increase.

In both 2014 and 2015, the sample size for all asset categories is 100%. All asset included in the assessment had sufficient data for Health Indexing.

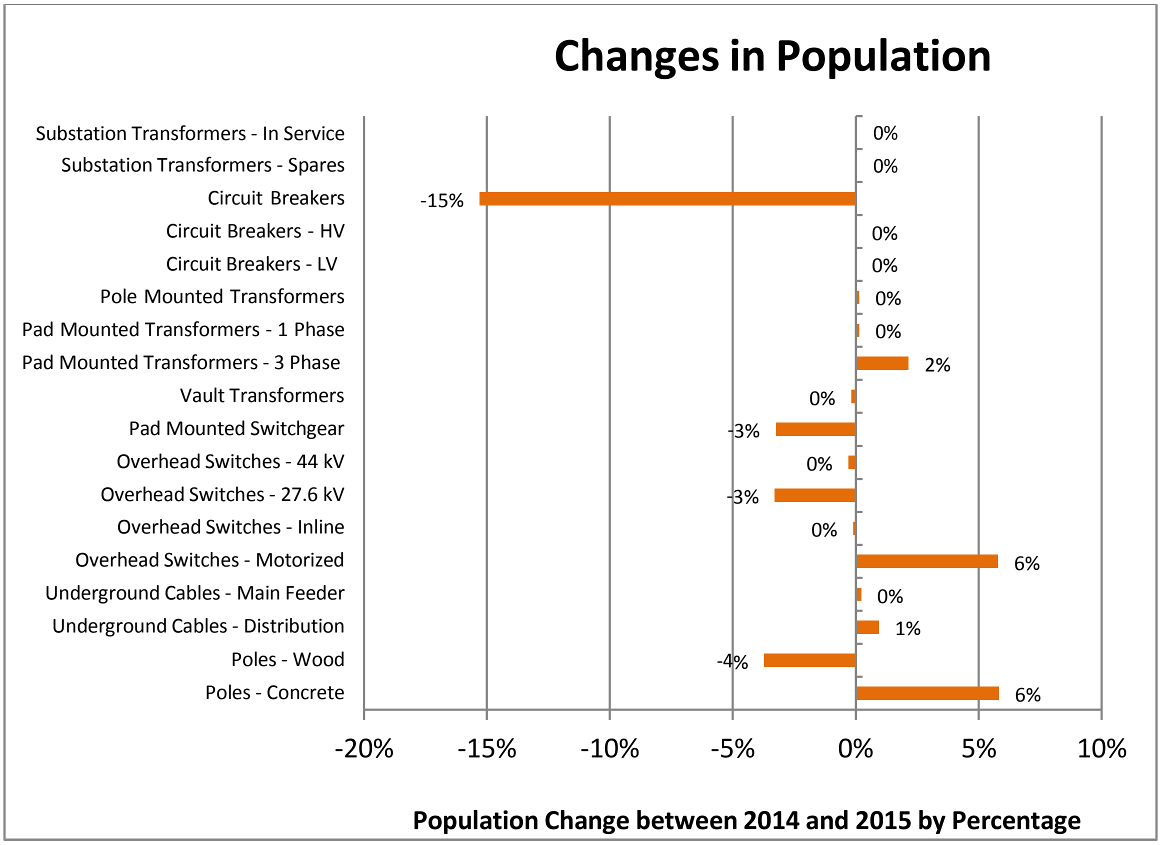


Figure III-9 Change in Population

Changes in Health Index Distribution

The changes in Health Index distribution between 2013 and 2014 are summarized in Table III-5 and graphically shown in Figure III-10. The overall trend with respect to Health Index distribution was assessed. Assets that showed an increasing percentage of "good" and/or "very good" or a decrease of "very poor", "poor", and/or "fair" were classified as having overall improved health distributions. Conversely, asset classes with a decreasing percentage of "good" and/or "very good" or an increasing percentage of "very poor", "poor", and/or "fair" were classified as having an overall decline in health.

Substation Transformers In Service: The trend shows an improvement in overall condition. Approximately 16% more were classified and very good and the average health index of the group increased by 5%.

Substation Transformers Spares: While the average HI score remained steady, fewer number of units were classified as very good and more units moved from fair to good condition.

Circuit Breakers: The trend shows a slight decline in overall condition. The average HI decreased from 94% to 93% in 2014. The number of breakers in very good condition decreased, but the number of good/fair units increased.

Pole Mounted Transformers: The trend shows an decline in overall condition. The overall average HI decreased. There are more units being classified as very poor, while fewer units are classified as very good.

Pad Mounted Transformers 1-phase and 3-phase: In both cases, the trend shows a slight downward shift in overall condition. In both cases the average overall HI decreased slightly and the percentage classified as very poor increased slightly. It should be noted that the percentage of 1 phase units in very good condition did increase by 4%.

Vault Transformers: The trend shows a slight decline in overall condition. Fewer units are classified as “very good”, while more are classified as “very poor”.

Pad Mounted Switchgear: The trend shows a significant improvement in overall condition. There was a 22% increase in units categorized as “very good”. The significant improvement in data availability lends more credibility to the 2015 assessment.

Overhead Switches: In general, the overall HI of overhead switches appears to have improved. It should be noted, however, that this may be because the HI formula changed between 2014 and 2015. It should also be noted that the 2015 assessment is based only on age and whether the switch was operated. The accuracy and credibility of the health index could therefore be improved.

Underground Cables, Main Feeder and Distribution: The overall health of underground cables appears to have improved. This is because of a refinement in the useful life assumption for non-tree retardant, direct buried cables. Since these cables are remaining in service longer than expected, the life curve and resulting health profile have been adjusted to reflect field experience.

Poles, Wood and Concrete: Both wood and concrete poles are showing an overall decline in health. For both categories, the average HI decreased by 6%. Additionally, the % of assets classified as very good deceased by 17% and 15% for wood and concrete poles respectively. These 2015 results are more credible because of increase inspections for both categories, as well as pole testing data for wood poles.

Table III-5 Summary Change in Health Index Distribution

Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	%	Change
Substation Transformers - In Service	2014	0.9%	-1%	1.9%	2%	13.9%	-6%	36.1%	-11%	47.2%	16%	81.8%	5%
	2015	0.0%		3.7%		8.3%		25.0%		63.0%		87.0%	
Substation Transformers - Spares	2014	8.3%	0%	0.0%	0%	16.7%	-17%	8.3%	25%	66.7%	-8%	80.3%	1%
	2015	8.3%		0.0%		0.0%		33.3%		58.3%		81.6%	
Circuit Breakers	2014	1.8%	-2%	0.2%	0%	1.6%	3%	3.9%	5%	92.5%	-6%	93.9%	-1%
	2015	0.2%		0.0%		4.9%		8.6%		86.3%		93.1%	
Circuit Breakers - HV	2014	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
	2015	0.0%		0.0%		0.0%		3.6%		96.4%		95.3%	
Circuit Breakers - LV	2014	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
	2015	0.3%		0.0%		5.6%		9.3%		84.8%		92.8%	
Pole Mounted Transformers	2014	1.6%	2%	0.5%	0%	6.2%	-1%	11.3%	4%	80.5%	-5%	91.9%	-2%
	2015	3.1%		0.5%		5.1%		15.5%		75.7%		89.9%	
Pad Mounted Transformers - 1 Phase	2014	0.7%	2%	4.4%	0%	6.9%	-2%	28.7%	-4%	59.3%	4%	87.4%	-1%
	2015	2.5%		4.1%		5.0%		25.1%		63.4%		85.9%	
Pad Mounted Transformers - 3 Phase	2014	0.5%	1%	2.1%	-1%	3.7%	-2%	9.4%	2%	84.2%	-1%	94.2%	-2%
	2015	1.8%		1.6%		1.8%		11.2%		83.6%		92.6%	
Vault Transformers	2014	1.7%	5%	7.3%	-2%	7.4%	-1%	13.1%	3%	70.6%	-4%	87.3%	-3%
	2015	6.3%		5.1%		6.4%		15.6%		66.6%		83.9%	
Pad Mounted Switchgear	2014	5.6%	2%	2.9%	-2%	6.8%	-4%	19.4%	-17%	65.3%	22%	83.6%	5%
	2015	7.1%		0.6%		2.9%		1.9%		87.5%		88.2%	
Overhead Switches - 44 kV	2014	0.0%	0%	4.7%	-2%	0.9%	4%	5.9%	8%	88.5%	-10%	94.7%	-6%
	2015	0.0%		2.4%		5.0%		13.6%		78.9%		89.2%	

Asset	Year	Very Poor		Poor		Fair		Good		Very Good		Average Health Index	
		%	Change	%	Change	%	Change	%	Change	%	Change	%	Change
Overhead Switches - 27.6 kV	2014	0.0%	0%	1.4%	-1%	2.8%	4%	2.3%	21%	93.4%	-24%	96.6%	-10%
	2015	0.0%		0.5%		7.3%		23.3%		68.9%		87.0%	
Overhead Switches - Inline	2014	1.3%	-1%	3.3%	0%	4.1%	6%	5.5%	25%	85.7%	-29%	92.9%	-11%
	2015	0.0%		3.5%		10.1%		30.3%		56.2%		82.1%	
Overhead Switches - Motorized	2014	7.7%	-8%	6.7%	-5%	1.9%	7%	5.8%	5%	77.9%	0%	85.4%	5%
	2015	0.0%		1.8%		9.1%		10.9%		78.2%		90.3%	
Poles - Wood	2014	9.1%	1%	8.9%	-4%	7.2%	19%	15.1%	1%	59.7%	-17%	79.1%	-6%
	2015	10.5%		5.1%		25.8%		16.2%		42.3%		72.8%	
Poles - Concrete	2014	0.0%	3%	0.1%	0%	1.0%	10%	3.8%	1%	95.1%	-15%	97.1%	-6%
	2015	3.4%		0.3%		10.7%		5.2%		80.4%		90.7%	

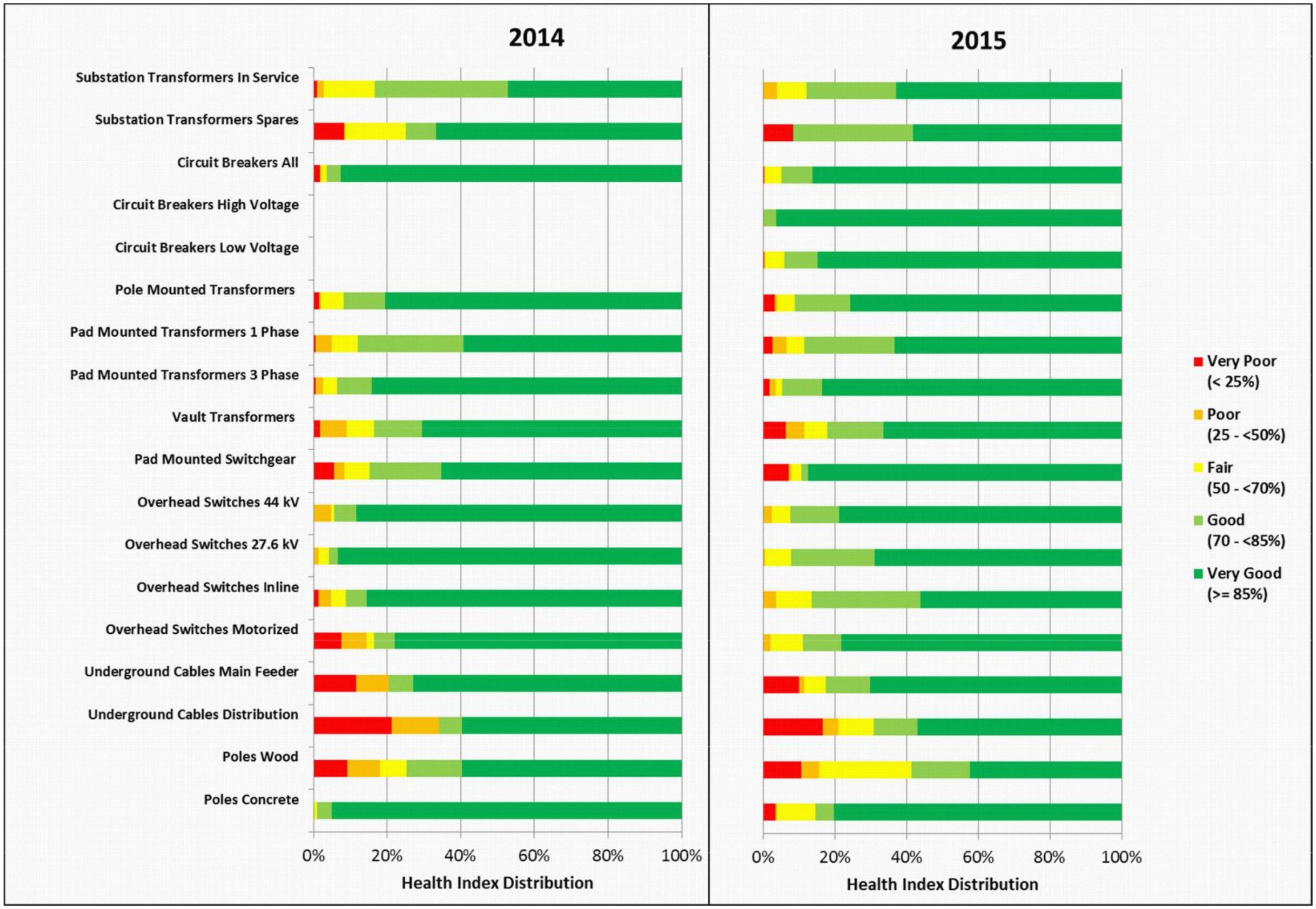


Figure III-10 Change in Health Index Distribution

IV CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the findings of this study.

1. A 2015 Asset Condition Assessment was conducted for nine of Enersource's key distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan and levelized Flagged for Action Plan were developed.

2. Similar to 2014, the Underground Cables category was found to be in the worst condition. Approximately 12% of main feeder and 21% of distribution cables were classified as "poor" or "very poor".

3. Another group of concern is Wood Poles where 16% are in "poor" or "very poor" condition. It should also be noted that 11% of Vault Transformers and 8% of Pad Mounted Switchgear classified as "poor" or "very poor".

4. The Underground Cables category was determined to have the highest flagged for action percentage among all the asset groups. At present, over 9% of main feeder and nearly 15% of distribution cables were flagged for action. Within the next 10 years, more than 40% of underground cable population is flagged for action.

5. Presently, 10% of wood poles have been flagged for action. This includes poles that require action because of the insulation used. In the next 10 years 35% of all wood poles will need to be addressed.

6. The availability of inspection records were significantly improved for a number of asset categories, namely circuit breakers, pad-mounted switchgear, and wood and concrete poles. Consequently, the DAIs for these asset groups (with the exception of wood poles because of a change in HI formula) increased dramatically.

7. A notable achievement is the collection and incorporation of Loading information for distribution transformers.

8. It should also be noted that data gaps for a number of asset categories were closed between 2014 and 2015. At present, only the following asset categories were identified to have data gaps: overhead switches and underground cables.

   Only age and operations records were used to assess overhead switches. It is recommended that visual inspections be conducted to gather condition information.

   Only age and failure history were used to assess underground cables. Enersource may consider diagnostic testing as such information will provide good, objective data for the Health Index.

9. A recommendation that applies to all asset categories is that Enersource should consider collecting corrective maintenance information. Although the most recent

inspection records are helpful in indicating an asset's current state, it does not give insight to past problems associated with an asset. Corrective maintenance history is useful in that it will highlight units or components of units that have been historically problematic or aging at an accelerated rate.

10. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. i.e. data for all condition parameters used in the HI formulas should be collected for all assets.

11. In future assessments, Enersource may wish to consider assessing additional asset categories. Examples are: station metal-clad/metal-enclosed switchgear, DC systems, relays, batteries.

12. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is recommended that Enersource continue to collect failure statistics so that Enersource-specific failure models can be developed and used in future assessments. Note that this is already being done for distribution transformers and underground cables. Similar collection of failure data should be extended to all asset classes.

13. It is important to note that the Flagged for Action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence Enersource's Asset Management Plan, such as obsolescence, system growth, regulatory requirements, municipal initiatives, etc.

V APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

1 SUBSTATION TRANSFORMERS

1.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Insulation	**12**	**1**	1	Oil Quality	**20**	**1**	Table 1-2
				2	Oil DGA	**40**	**1**	Table 1-3
				3	Winding Doble	**4**	**1**	Table 1-4
				4	Bushing	**1**	**1**	Table 1-5
2	Cooling	**1**	**1**	1	Winding Temp Gauge	**1**	**1**	Table 1-5
				2	Oil Temp Gauge	**1**	**1**	Table 1-5
				3	Mech Box – Fan Supply	**1**	**1**	Table 1-5
3	Sealing & Connection	**1**	**1**	1	Corrosion / Paint Condition	**1**	**1**	Table 1-5
				2	Tank Oil Level	**2**	**1**	Table 1-5
				3	Gasket	**3**	**1**	Table 1-5
4	Service Record	**6**	**1**	1	Loading	**2***	Table 1-6	Table 1-6
				2	Age	**1**	**1**	Figure 1-1
Overall HI De-Rating Multiplier (DR)				DGA Gas Trend				
* Loading weight = 0 for spare transformers								

1.1.2 Condition Criteria

<u>Oil Quality</u>

The "Oil Quality" parameter is a composite of the following oil properties: moisture, dielectric strength, interfacial tension, color, and acidity.

Table 1-2 Oil Quality Test Criteria

Score	Description
4	Overall Factor is less than 1.2
3	Overall Factor between 1.2 and 1.5
2	Overall Factor is between 1.5 and 2.0
1	Overall Factor is between 2.0 and 3.0
0	Overall Factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

		Scores				
		1	2	3	4	Weight
Moisture PPM (T °C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
Dielectric Str. [kV] D877		>40	>30	>20	Less than 20	3
Interfacial Tension (IFT)* [dynes/cm]	230 kV $\leq$ V	>32	25-32	20-25	Less than 20	2 *
	69 kV <V< 230	>30	23-30	18-23	Less than 18	
	V $\leq$ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV $\leq$ V	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <V< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	V $\leq$ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 1-3 Transformer DGA Criteria

Score	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Winding Doble Test

Table 1-4 Winding Doble Test Criteria

Score	Description
4	power factor reading $\leq$ 0.5%
3	0.5% < power factor reading $\leq$ 0.7%
2	0.7% < power factor reading $\leq$ 1.0%
1	1.0% < power factor reading $\leq$ 2.0%
0	power factor reading > 2.0%

Age

Assume that the failure rate Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for Substation Transformers are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

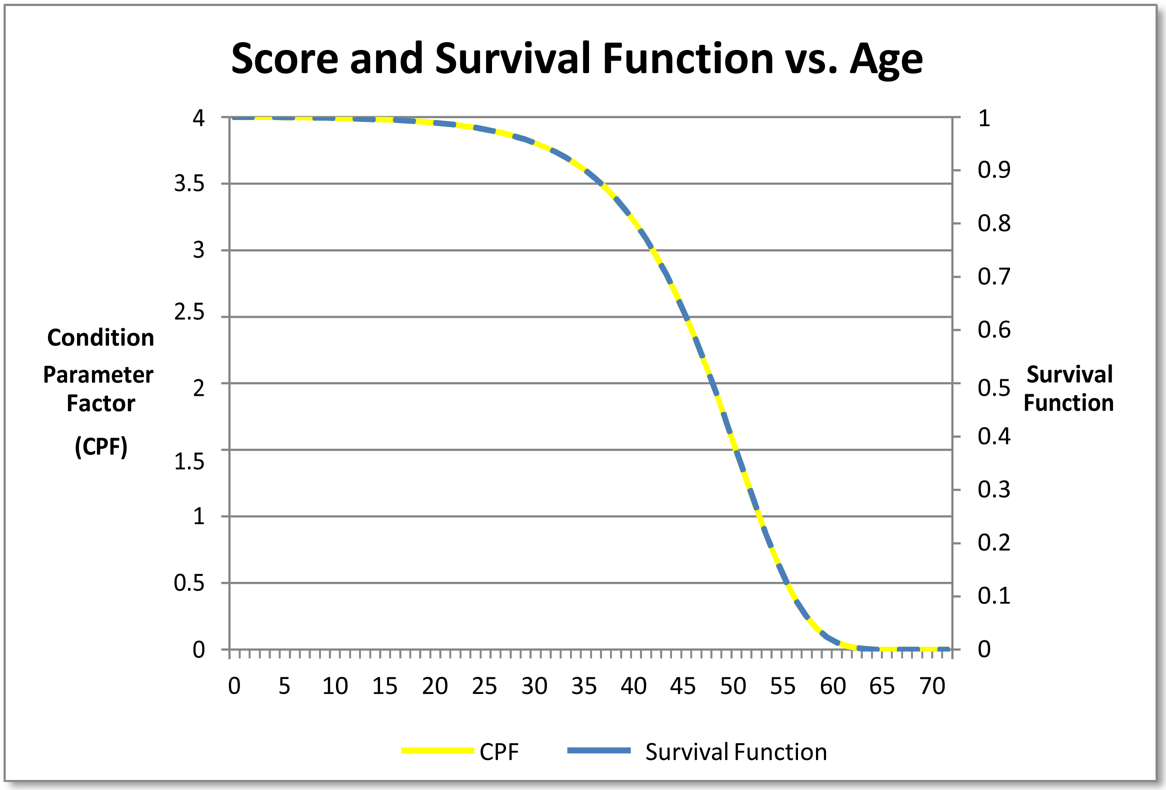


Figure 1-1 Substation Transformers Age Criteria

Visual Inspections

Table 1-5 Visual Inspection Criteria

Score	Condition Description
4	OK
0	Not OK

Loading History

Table 1-6 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

1.2 Age Distribution

The average age of all in service units was 23. Approximately 17% of all units were 40 or older. The age distribution for in service Substation Transformers was as follows:

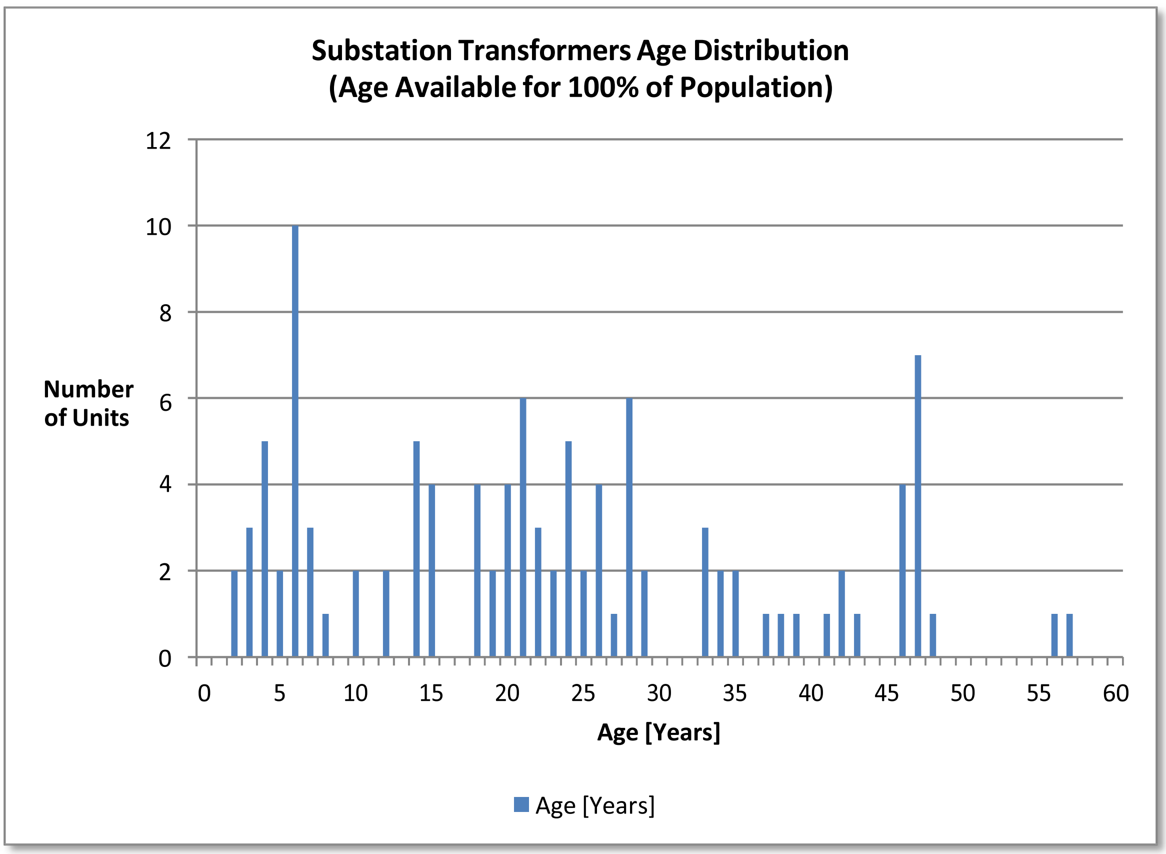


Figure 1-2 Substation Transformers Age Distribution

1.3 Health Index Results

There are 108 in service Substation Transformers at Enersource. Of these, there are 108 units with sufficient data for Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units are shown below. The average Health Index for this asset group was 87%. Four units were found to be in "poor" condition.

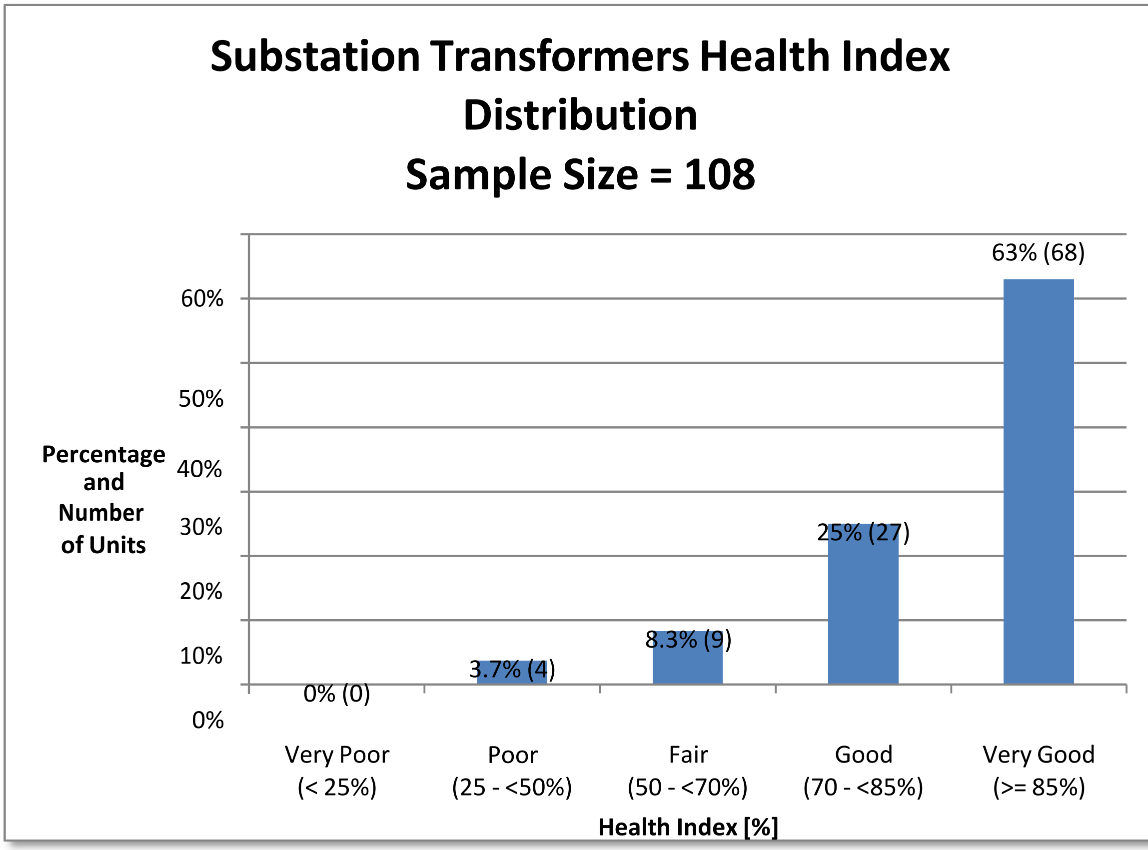


Figure 1-3 Substation Transformers Health Index Distribution

1.4 Flagged for Action Plan

It is assumed that Substation Transformers are proactively replaced.

In this study, a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one.

Each unit's criticality is defined as follows:

$$Criticality = (Criticality_{max} - Criticality_{min}) * Criticality\_Multiple + Criticality_{min}$$

where:

$Criticality_{max} = 1/(70\%) = 1.43$ (the units with highest relative importance should be replaced when their POF reaches 70%)

$Criticality_{min} = 1/(90\%) = 1.11$ (the units with lowest relative importance can wait until their POF reaches 90% to be replaced)

$$Criticality\_Multiple = \frac{\sum_{CF=1}^{\forall CF} (CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF} (WCF_{CF})}$$

The factors, weights and the score system of each factor are as follows:

Criticality Factor (CF)	Weight (WCF)	Score (CFS)
Number of Customers	25	Low=0 High=1
Oil Containment	10	Yes=0 No=1
Location (near water creeks)	50	No=0 Yes=1
Transformer Primary Protection	15	Breaker =0 Fuse=1

The table below shows examples of criticalities for three separate units.

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Number of Customers	Low	0	0	High	1	25	High	1	25
Oil Containment	Yes	0	0	No	1	10	No	1	10
Location (near water creeks)	No	0	0	No	0	0	Yes	1	50
Transformer Primary Protection	Breaker	0	0	Breaker	0	0	Fuse	1	15
	Criticality Multiple		0	Criticality Multiple		0.35	Criticality Multiple		1
	Criticality		(1.43-1.11) *0 + 1.11 = **1.11**	**Criticality**		(1.43-1.11) *0.35 + 1.11 = **1.22**	**Criticality**		(1.43-1.11) *1 + 1.11 =**1.43**

As previously noted a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. The flagged for action plan for in service Substation Transformers was as follows:

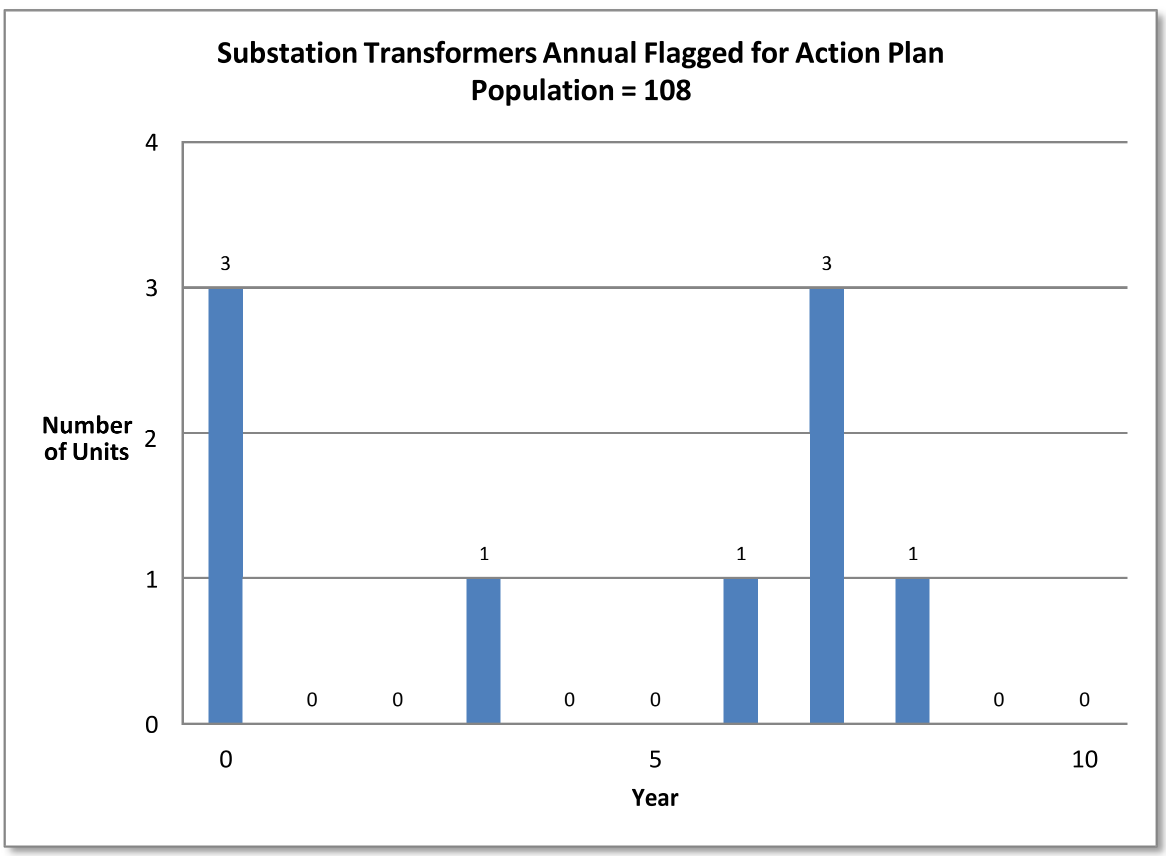


Figure 1-4 Substation Transformers Flagged for Action Plan

Table 1-7 Transformers Flagged for Action within the Next Ten Years

Serial Number	Transformer Name	Substation	Age	Criticality Percentage	Health Index	Action Year	Year
09J367117	7T1	ORCH HTS	6	0.75	26.4%	0	0
09J297042	7T2	BIRCHVIEW	6	0.5	29.6%	0	0
09J367118	5T1	ORCH HTS	6	0.5	31.8%	0	0
10JC299370001	1T1	MINEOLA	5	0.5	48.7%	3	3
291012	11T1	HENSAL	56	0.25	52.0%	6	6
09J297043	5T2	BIRCHVIEW	6	0.5	55.1%	7	7
08J100164	41T2	BEXHILL	7	0	55.4%	7	7
11JC299370009	66T1	BROMSGROVE	4	0	55.7%	7	7
31181	54T1	BATTLEFORD	22	0.35	57.7%	8	8

1.5 Spare Substation Transformers

There are 12 Spare Substation Transformers at EMH. Their age distribution was as follows. Approximately 58% of all units were 40 or older.

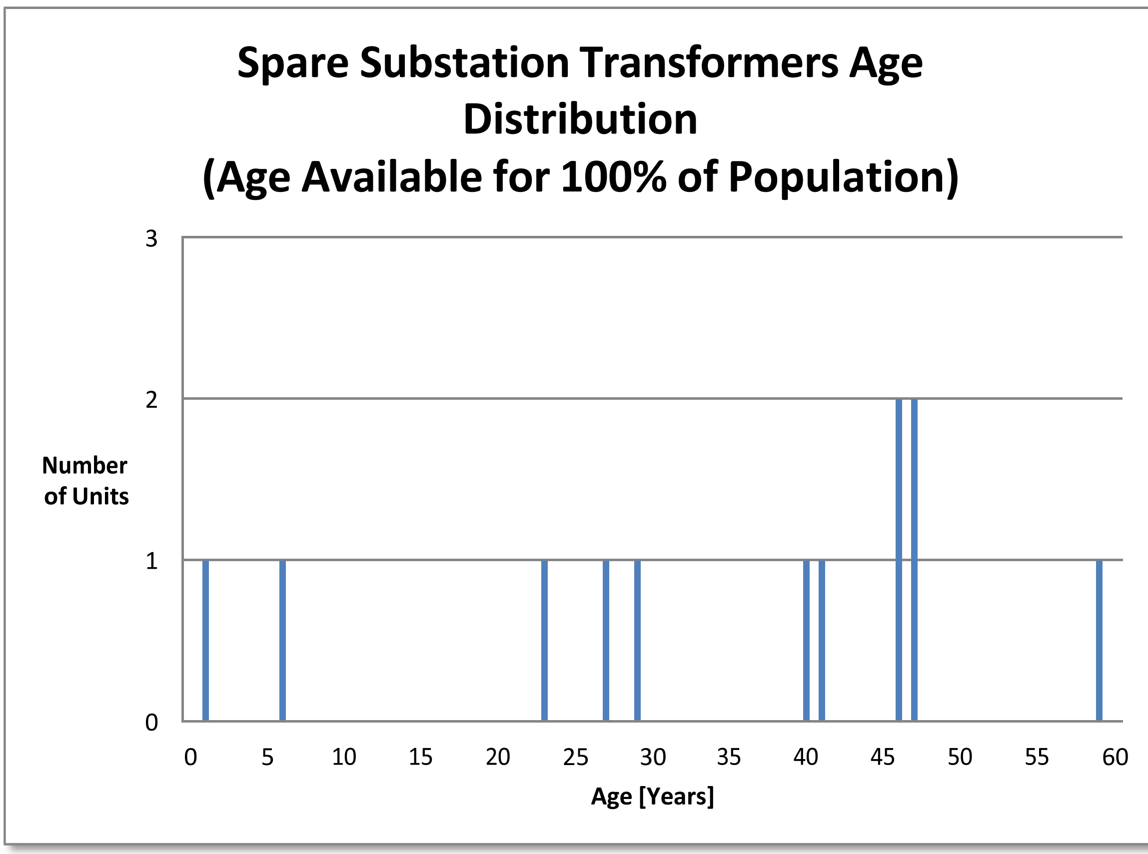


Figure 1-5 Spare Substation Transformers Age Distribution

Of the 12 Spare Substation Transformers at Enersource, there are 12 units with sufficient data for Health Indexing. The Health Index Distribution in terms of number of units and percentage of units are shown below. The average Health Index for this asset group was 82%.

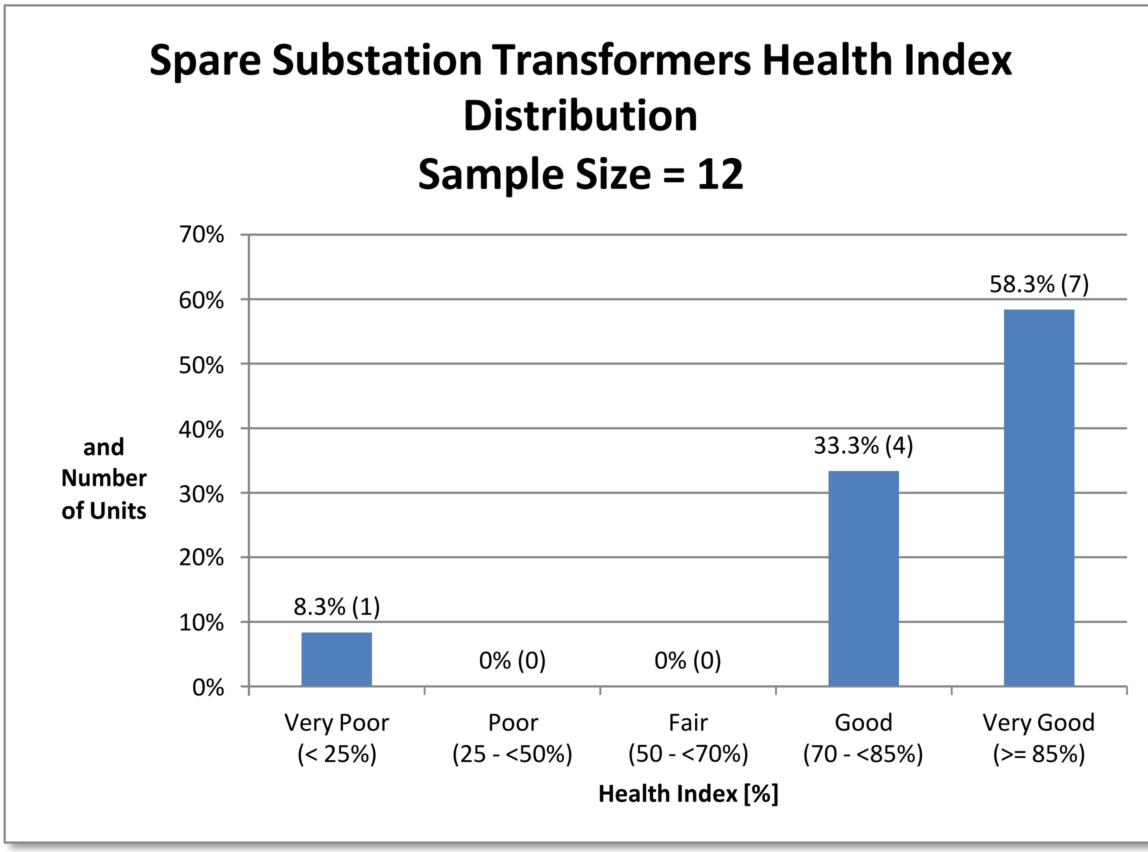


Figure 1-6 Spare Substation Transformers Health Index Distribution

1.6 Data Assessment

The data for in service Substation Transformers included inspection results, loading, age, and oil quality, dissolved gas analysis, and Doble tests.

At 87%, the average of DAI of this group was slightly better than in the previous year (84% in 2014). There has also been an improvement in the collection of inspection data. Nearly 85% of the population had inspection data in 2015 (an improvement over the 76% of units with inspection in 2014).

In the past, it was recommended that IR thermography information be collected. Enersource only performs IR scans on an as-needed basis and problems found are corrected within a short timeframe. Further, problems found during an IR scan (poor connection or ventilation) may be found during regular inspections. For these reasons, the IR scan has been removed as a data gap. Grounding information, which was identified in 2014 as a data gap, is currently being collected and can be incorporated into future assessments.

2 CIRCUIT BREAKERS

This asset category is sub-categorized into High Voltage (HV) and Low Voltage (LV) Breakers.

2.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

2.1.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Parameter and Weights

Condition Parameter (CP)							Sub-Condition Parameter (SCP)							
n	Description	Weight (WCP)				De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)				De-Rating Multiplier (DR_SCP)	SCP Criteria
		Oil	SF6	Vacuum	Air Magnetic				Oil	SF6	Vacuum	Air Magnetic		
1	Operating Mechanism	14	11	7	14	1	1	Lubrication	9	7	5	9	1	Table 2-2
							2	Operating Mechanism	5	4	2	5	Table 2-5	Table 2-2
2	Contact Performance	7	7	7	7	1	1	Contact Resistance	2	2	2	2	1	Table 2-4
							2	Contact surfaces	1	1	1	1	1	Table 2-2
							3	Contact Alignment	1	1	1	1	1	Table 2-2
3	Arc Extinction	9	5	9	9	1	1	Arc Interrupter	1	1	0	0	1	Table 2-2
							2	Arc Chute	0	0	0	1	1	Table 2-2
4	Insulation	2* 0**	2* 0**	2* 0**	2* 0**	1	1	Insulation	2* 0**	2* 0**	2* 0**	2* 0**	1	Table 2-2
							2	Phase Barriers	1* 0**	2* 0**	2* 0**	2* 0**	1	Table 2-2
5	Service Record	10	8	5	9	1	1	Age	1	1	1	1	1	Figure 2-1
* High Voltage (HV) breakers **Low Voltage (LV) breakers														

2.1.2 Condition Criteria

Visual Inspection

Table 2-2 Visual Inspection Criteria

Score	Condition Description
4	OK
0	Not OK

Measurement

Breaker timing and contact resistance measurements indicate the proper function of the breaker as designed. It is crucial that the breaker meets these specifications for proper and reliable operation

Table 2-3 Resistance Test Criteria

Score	Condition Description
4	Measurement <= 80% Specification limit *
3	Measurement (80%, 100%] specification limit
1	Measurement (100%, 120%] specification limit
0	Measurement > 120% specification limit

* CB type dependent (see Table 2-4)

Table 2-4 Contact Resistance Specification Limit

Breaker Type	Contact Resistance Specification Limit [μΩ]			
	<= 69 kV	110 – 230 kV	345 kV	765 kV
Oil	300	600	900	
Gas	150	150	150	300
Vacuum & Air Magnetic	250	250	250	250

Operating Mechanism

Table 2-5 Multiplier for Operating Mechanism

Multiplier	Operating Type
1	Solenoid
0.9	Spring

Age

Assume that the failure rate Circuit Breakers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 50 years the probability of failures (P_f) for Circuit Breakers are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

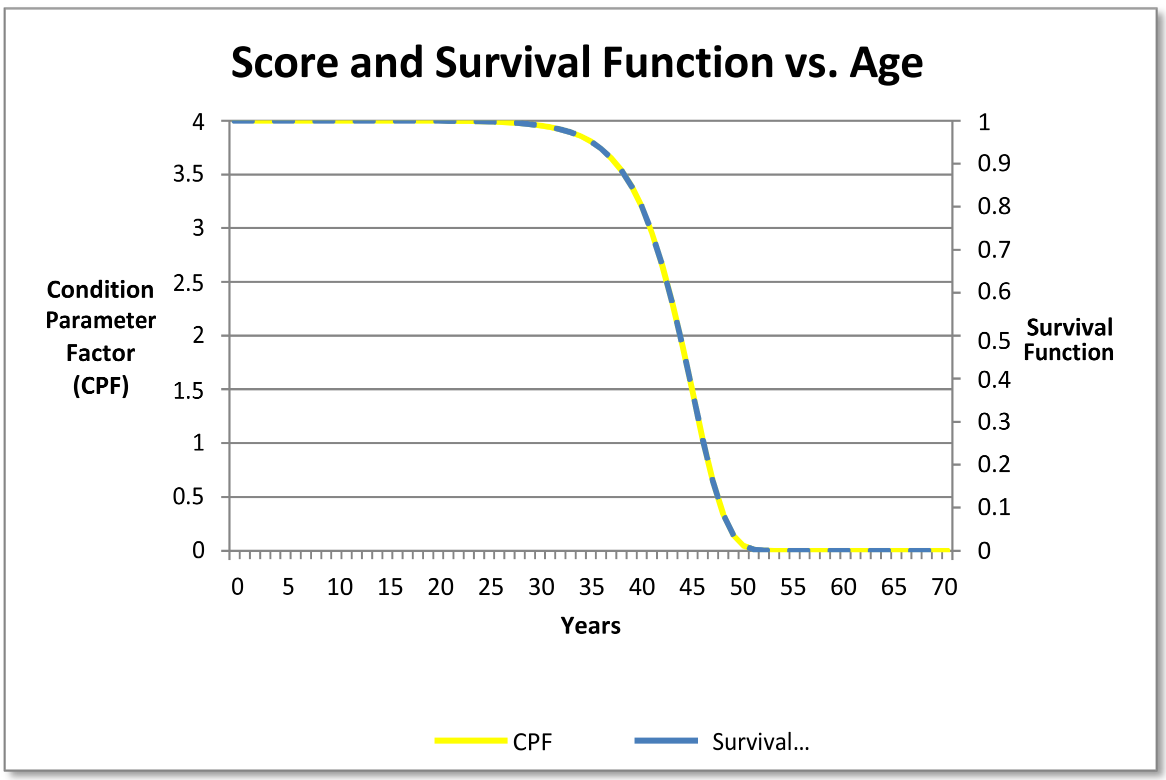


Figure 2-1 Circuit Breakers Age Criteria

2.2 Age Distribution

The average age of the HV population was 23 years old, with 7% of the population being 40 years or older.

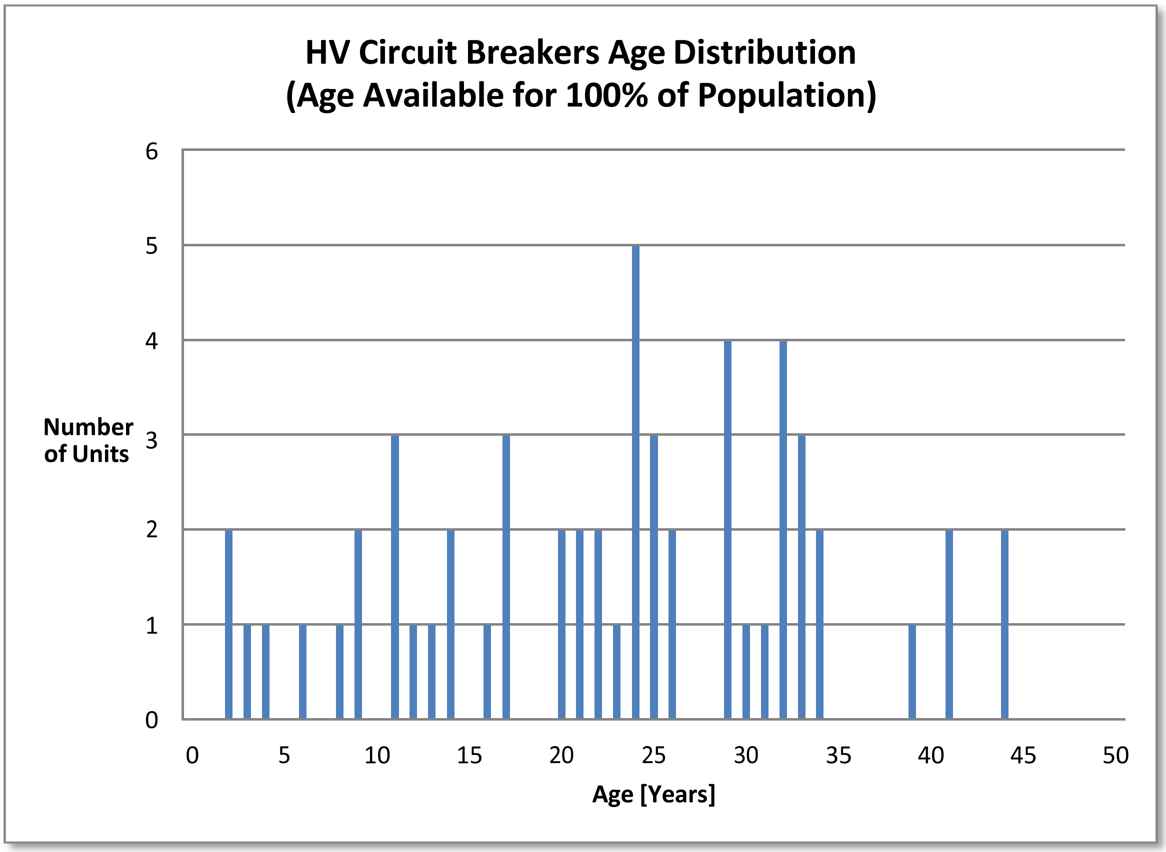


Figure 2-2 HV Circuit Breakers Age Distribution

The age distribution for this asset class is shown on the figure below. The average age of the HV population was 21 years old, however 16% of the population was 40 years or older.

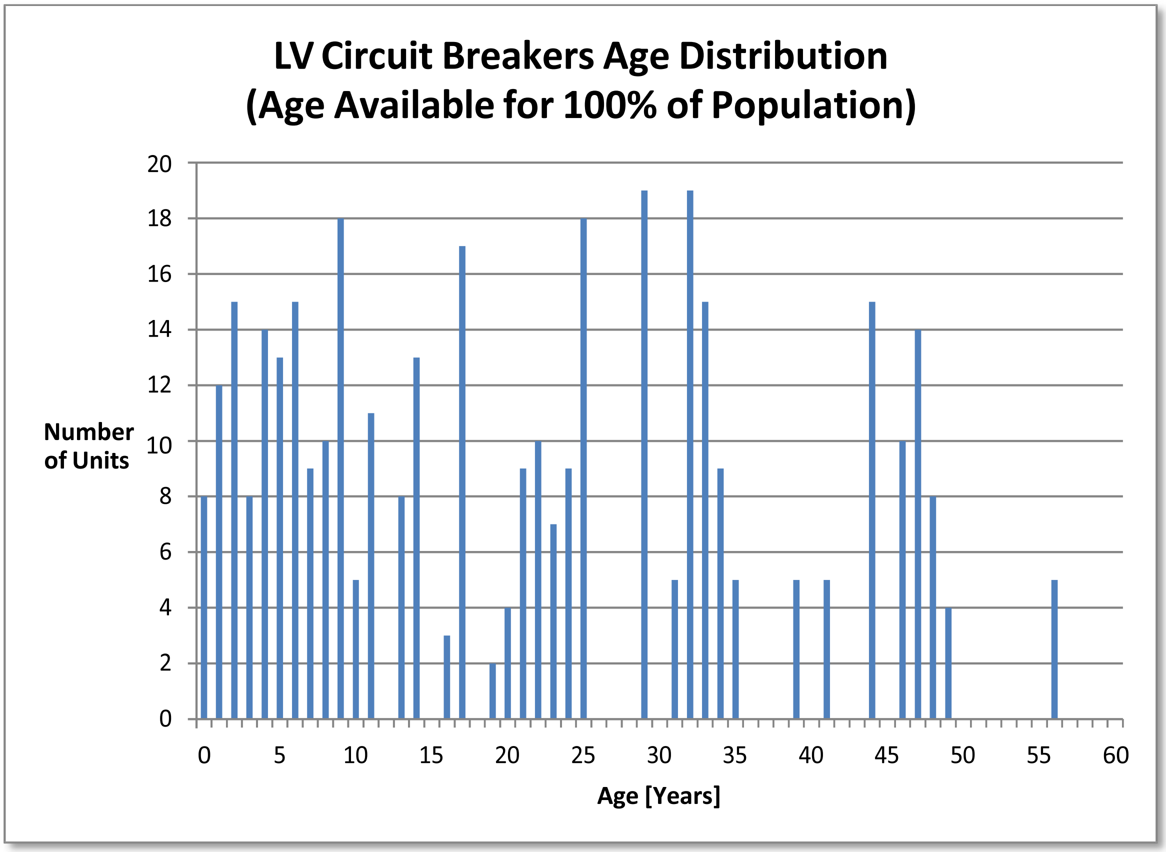


Figure 2-3 LV Circuit Breakers Age Distribution

2.4 Health Index Results

High Voltage Breakers

There are 56 High Voltage (HV) Circuit Breakers at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 94%. None were found to be in "poor" or "very poor" condition.

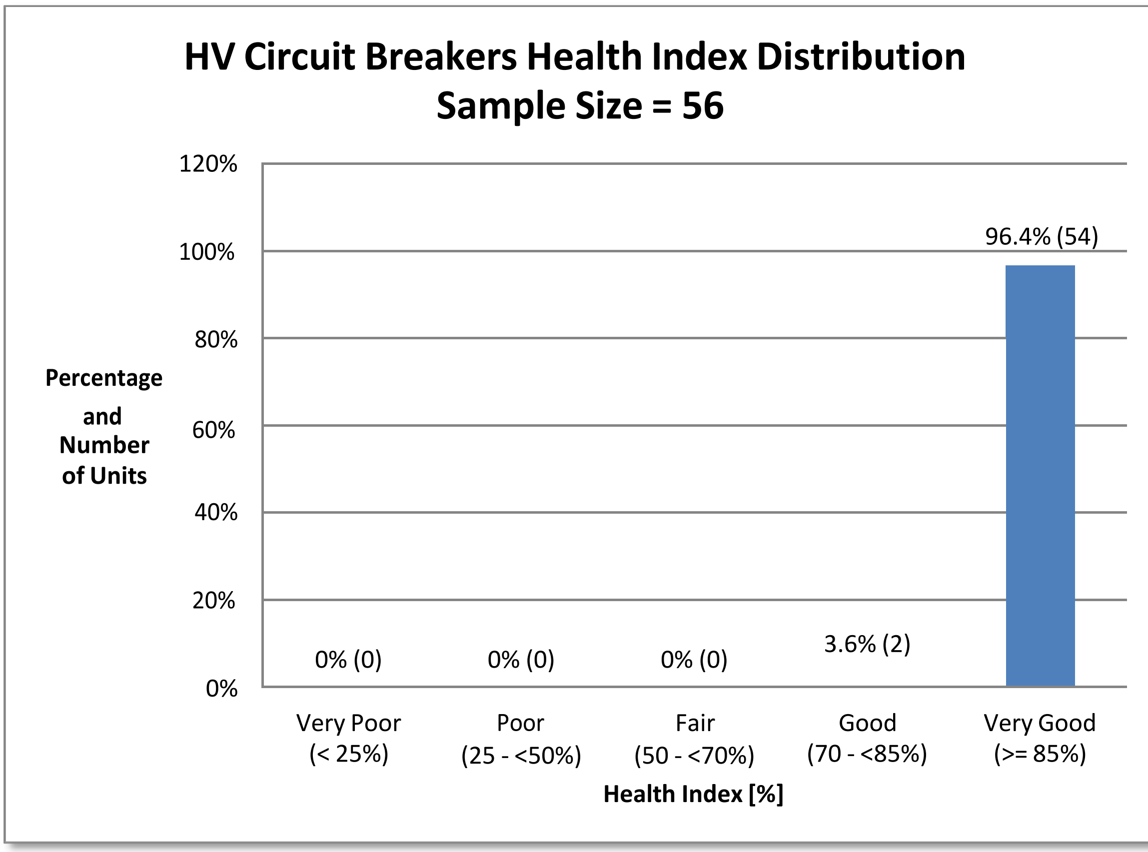


Figure 2-4 HV Circuit Breakers Health Index Distribution

Low Voltage Breakers

There are 376 Low Voltage (LV) Circuit Breakers at Enersource. All had sufficient data for Health Indexing.

The average Health Index for this asset group was 94%. None were found to be in “poor” or “very poor” condition.

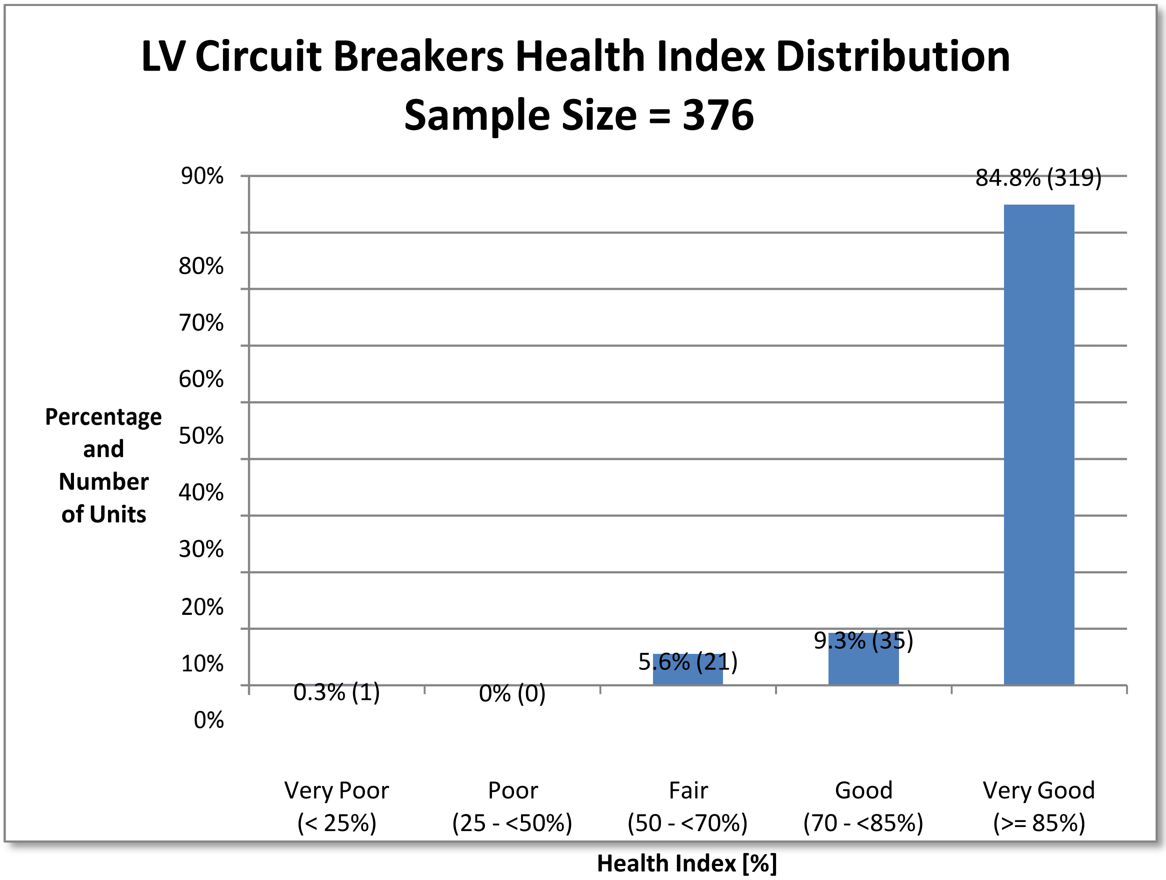


Figure 2-5 LV Circuit Breakers Health Index Distribution

2.5 Flagged for Action Plan

It is assumed that Circuit Breakers were proactively replaced.

A unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. All units are assumed to have equal criticalities, selected such that a unit with a probability of failure of 70% becomes a candidate for replacement. i.e. Criticality = 1.43.

The flagged for action plans for Circuit Breakers is as follows:

High Voltage Breakers

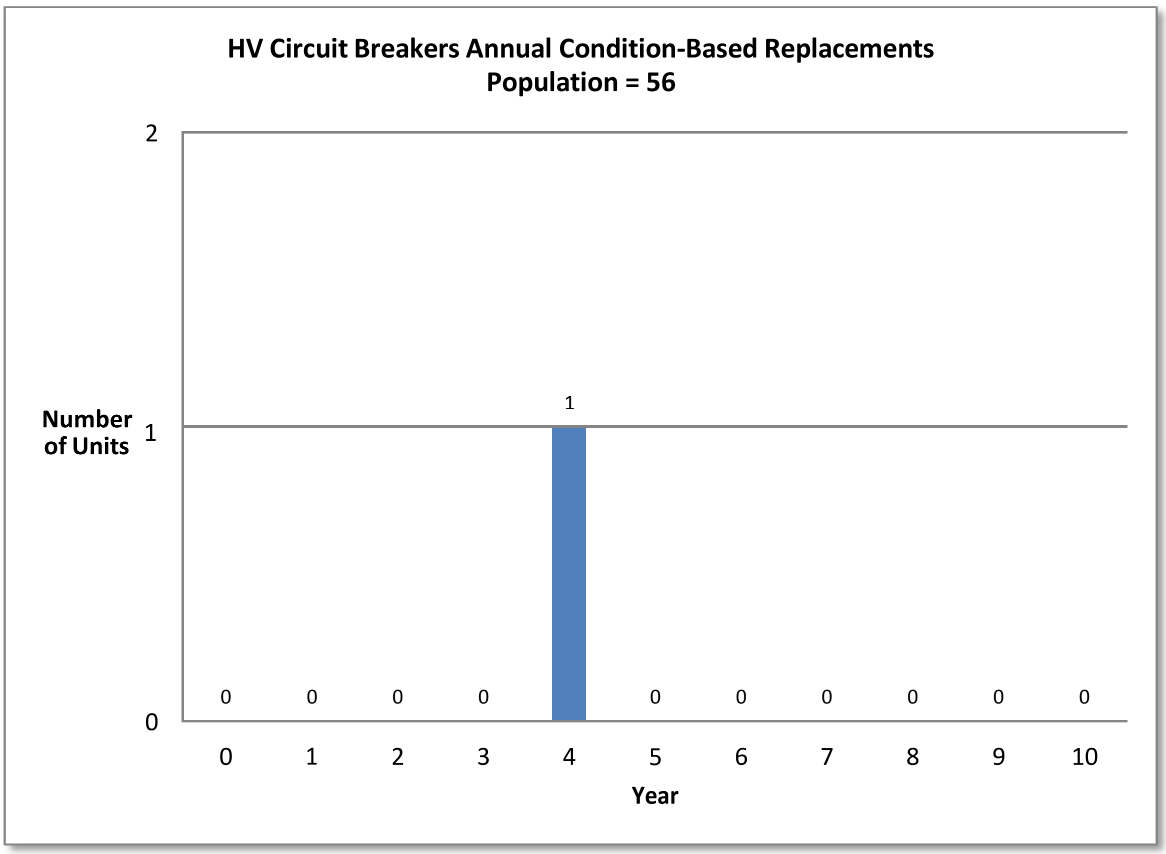


Figure 2-6 HV Circuit Breakers Flagged for Action Plan

Low Voltage Breakers

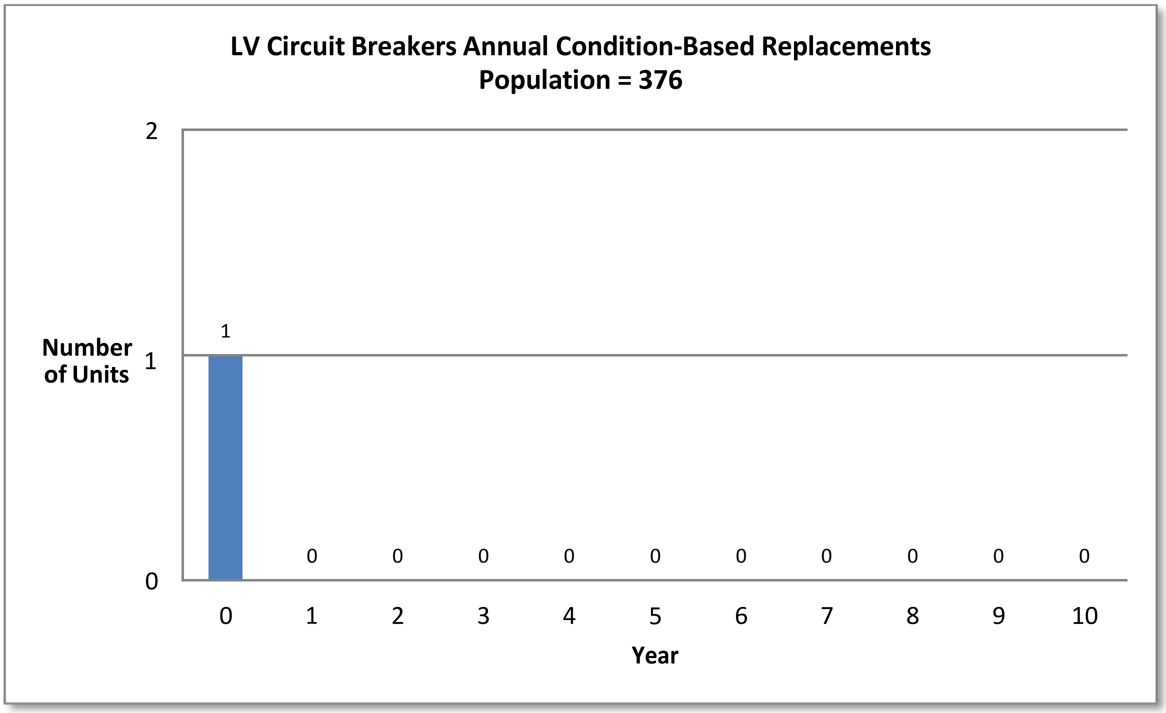


Figure 2-7 LV Circuit Breakers Flagged for Action Plan

2.6 Data Analysis

Data for Circuit Breakers included age, contact resistance, and inspection results. The average DAI for this asset group improved significantly from 71% last year to 94% this year. This is a result of an improvement in the collection of inspection data, i.e. all breakers had inspection data in 2015.

In 2014 timing tests were identified as a data gap. Enersource does perform timing specification tests where the overall trip time of a breaker is tested as part of the breaker maintenance cycle. This information may be incorporated in future assessments.

The condition of some additional components or objects addressed in the data gaps identified in 2014 can be found from inspection items that are already part of Enersource's breaker inspection program (e.g. operating counter, arcing contact). If possible, these should be incorporated into future assessments. Other items (e.g. vacuum bottle) cannot be inspected or will have minimal impact to the health index value (e.g. loading). These items are therefore being removed as data gaps.

It is recommended that Enersource record the number of fault operations as such operations will degrade the breaker contact. Enersource should also consider collecting corrective maintenance records for breakers. Such information will provide insight to the historically problematic units or breaker components.

3 POLE MOUNTED TRANSFORMERS

3.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	1	1	1	Tank Corrosion	1	1	Table 3-2
2	Connection and Insulation	2	1	1	Oil Leak	1	1	Table 3-2
				2	Elbow	4	1	Table 3-2
3	Service Record	4	1	1	Overall	3	1	Table 3-2
				2	Age	3	1	Figure 3-1
				3	Oil Boil	1	1	Table 3-2
				4	Loading	5	1	Table 3-4
Overall HI De-Rating Multiplier (DR)				PCB and/or Leaker				Table 3-5

3.1.2 Condition Criteria

Visual Inspection

Table 3-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Overloading

Table 3-3 Overloading Criteria

Score	Condition Description
4	N
0	Y

Loading History

Table 3-4 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Pole Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\{3(t\text{-}a)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f\text{-}e^{-a\{3})/\{3}}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

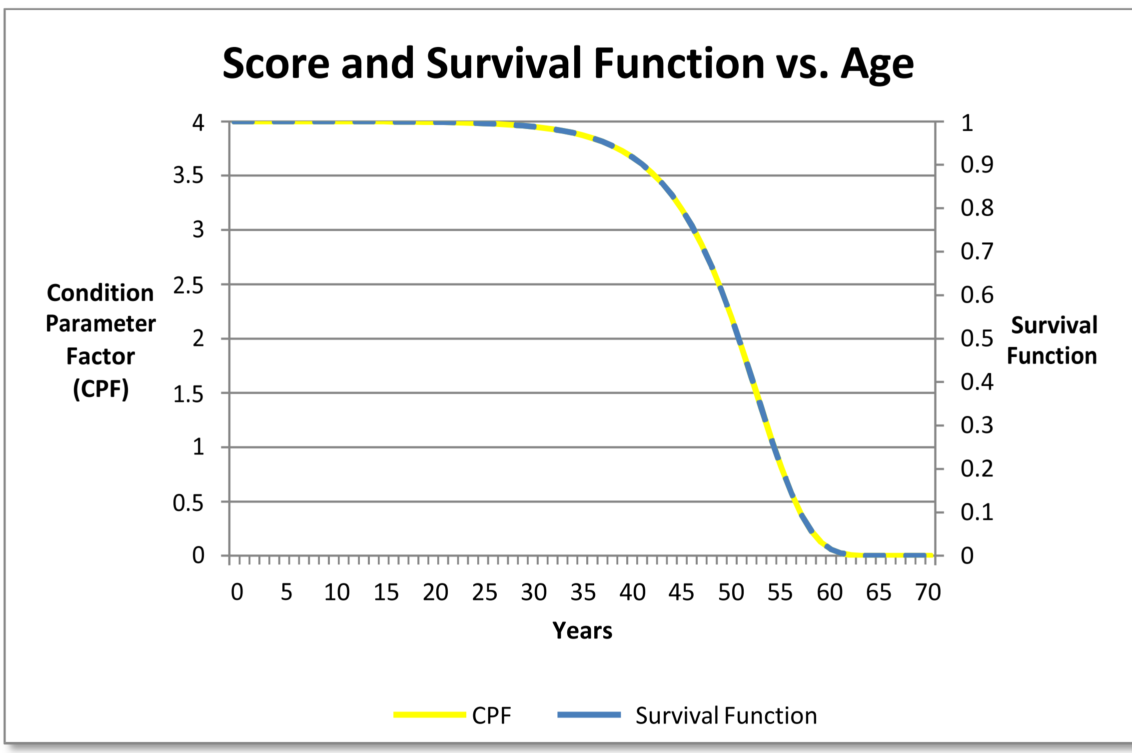


Figure 3-1 Pole Mounted Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 3-5 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	(PCB > 2 ppm) AND (Major Leaker)	0.1
Else if	PCB >= 50 ppm	0.1
Else if	(2 <= PCB < 50 ppm) OR (Major Leaker)	0.25
Else if	Moderate Leaker	0.7
Else		1

3.2 Age Distribution

The average age of the population was 20. Approximately 8% of the population was 45 years or older. The age distribution for this asset class was as follows:

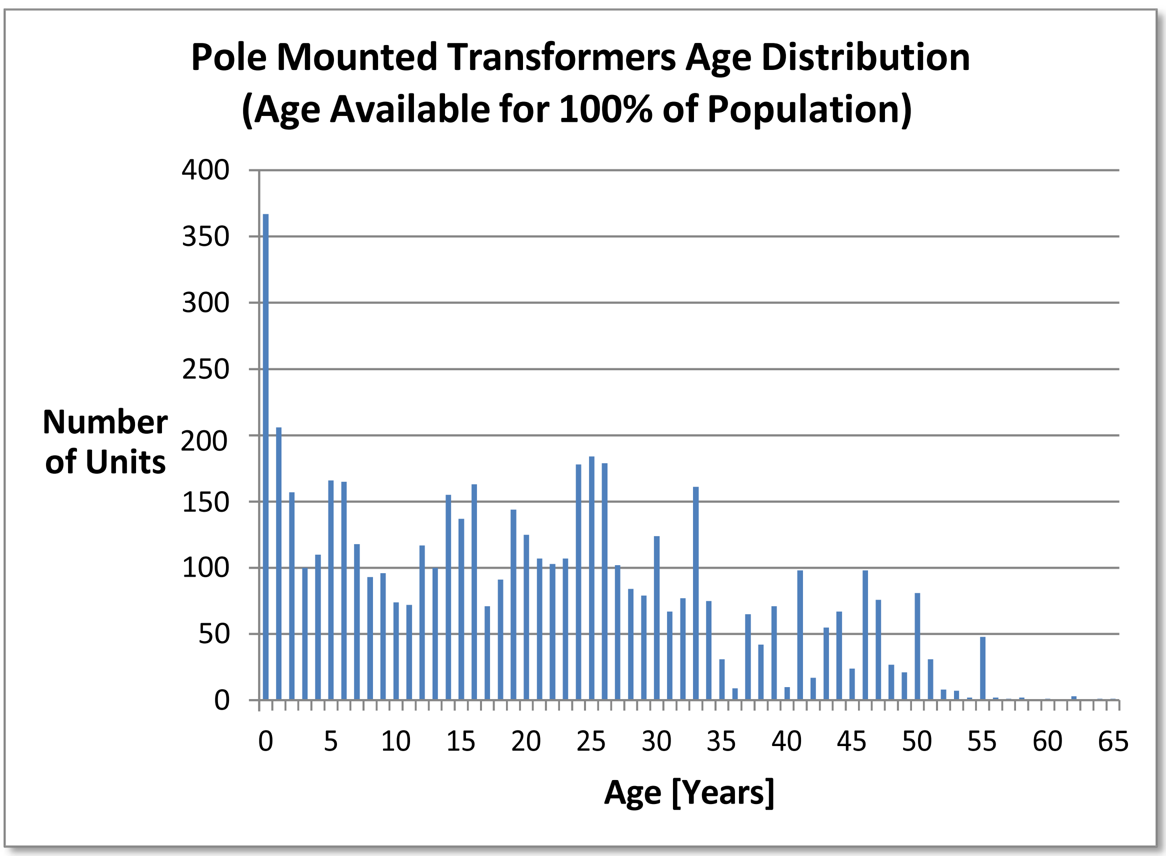


Figure 3-2 Pole Mounted Transformers Age Distribution

3.3 Health Index Results

There are 5353Pole Mounted Transformers at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 92%. Approximately 4% of the population was found to be in “poor” or “very poor” condition. These include units that have PCBs and/or are leakers.

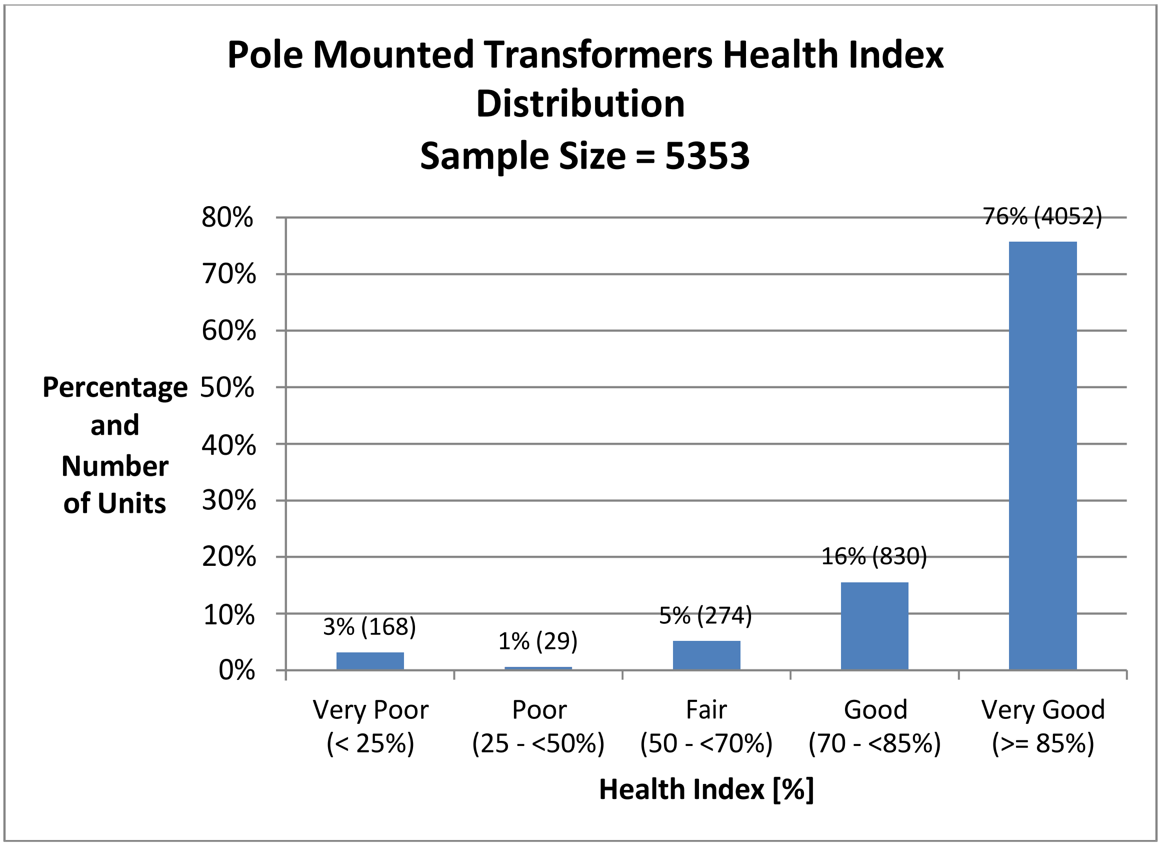


Figure 3-3 Pole Mounted Transformers Health Index Distribution

3.4 Flagged for Action Plan

As it is assumed that Pole Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate.

The flagged for action plan for Pole Mounted Transformers is as follows:

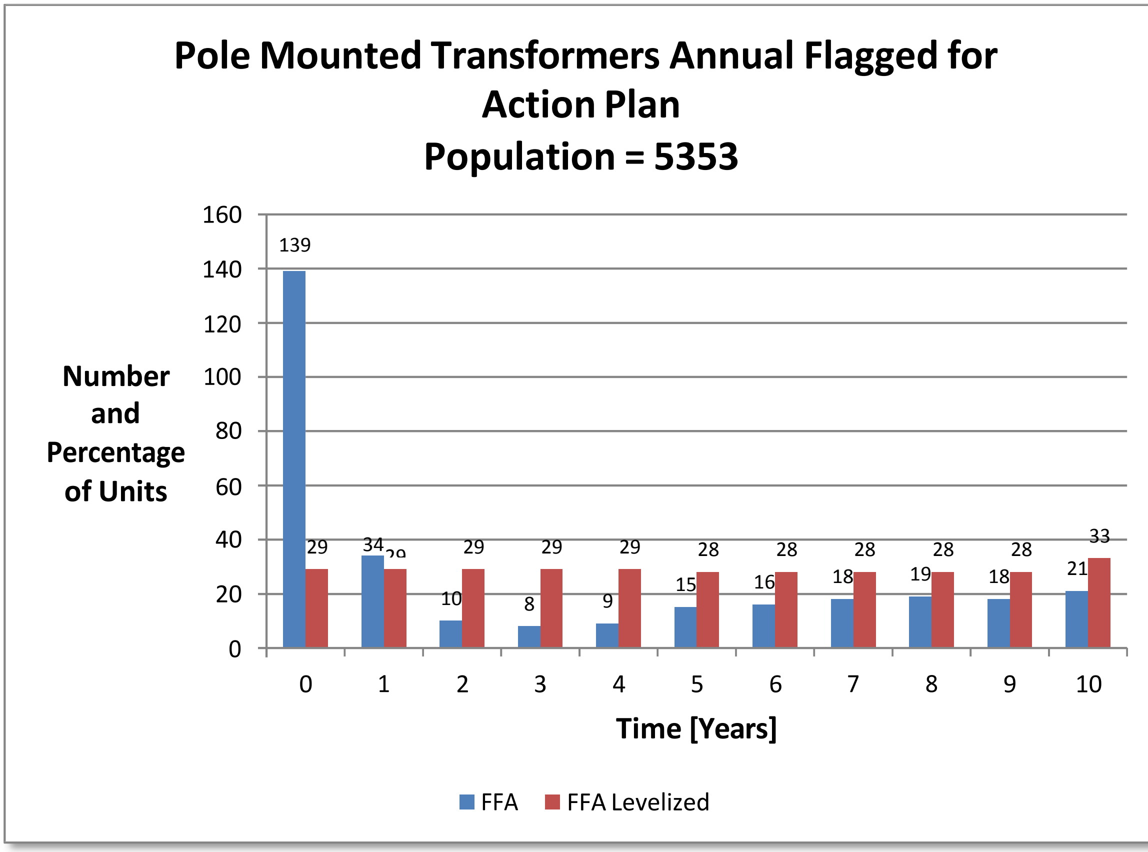


Figure 3-4 Pole Mounted Transformers Flagged for Action Plan

3.5 Data Analysis

The average DAI for Pole Mounted transformers increased from 75% in 2014 to 77% in 2015. A significant improvement for this asset category is the collection and incorporation of loading data into the Health Index calculation.

Since 2014, connection (bushing) and loading have been collected and incorporated into the Health Index assessment. As such, there are no data gaps remaining for this asset.

4 PAD MOUNTED TRANSFORMERS

4.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	1	1	1	Enclosure Damage	4	1	Table 4-2
				2	Paint	1	1	Table 4-2
				3	Access	1	1	Table 4-2
				4	Base	2	1	Table 4-2
2	Connection and Insulation	1	1	1	Oil Leak	1	1	Table 4-2
				2	Connection	2	1	Table 4-2
3	Service Record	3	1	1	Overall	4	1	Table 4-2
				2	Age	3	1	Figure 4-1
				3	Loading	4	1	Table 4-3
Overall HI De-Rating Multiplier (DR)				PCB and/or Leaker				Table 4-4
HI Maximum Limit				Overall Condition will limit maximum HI value				Table 4-5

4.1.2 Condition Criteria

<u>Visual Inspection</u>

Table 4-2 Visual Inspection Criteria

Score	**Condition Description**			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 4-3 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Pad Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$\mathbf{f} = e^{\{3(t\text{-}a)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f\text{-}e^{-a\{3})/\{3}}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

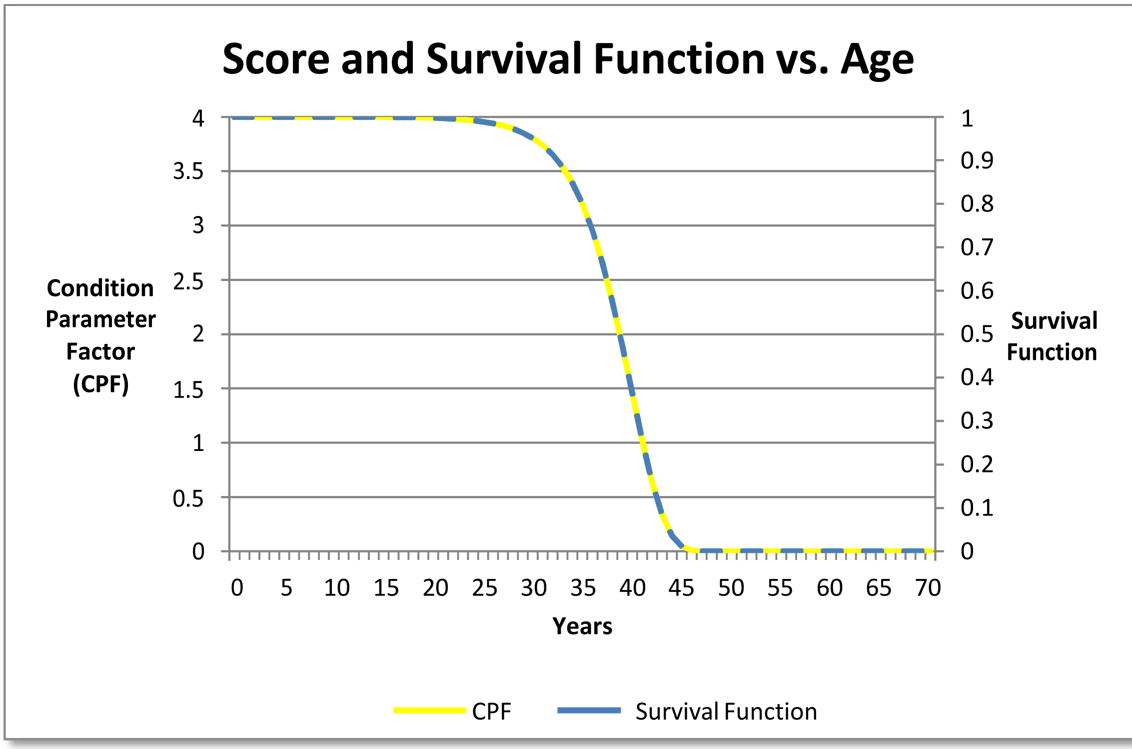


Figure 4-1 Pad Mounted Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 4-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	(PCB > 2 ppm) AND (Major Leaker)	0.1
Else if	PCB >= 50 ppm	0.1
Else if	(2 <= PCB < 50 ppm) OR (Major Leaker)	0.25
Else if	Moderate Leaker	0.7
Else		1

HI Maximum Limit

An additional Health Index limiting value is also applied. This is based on the asset's overall condition determined from Enersource's inspections. For example, if calculated HI of a certain unit is 56% (from the composite parameters) but the overall parameter score is "poor", the final HI of that asset will be limited to 50%. If the calculate HI is 38%, the final HI will be 38%.

Table 4-5 HI Maximum Limit

Overall Condition (based on Inspections)	HI Maximum Limit
VERY POOR	25%
POOR	50%
FAIR	70%

4.2 Age Distribution

Single Phase Pad Mounted Transformers

The average age of all single phase units was 21 years. Approximately 9% of the population is 35 years or older.

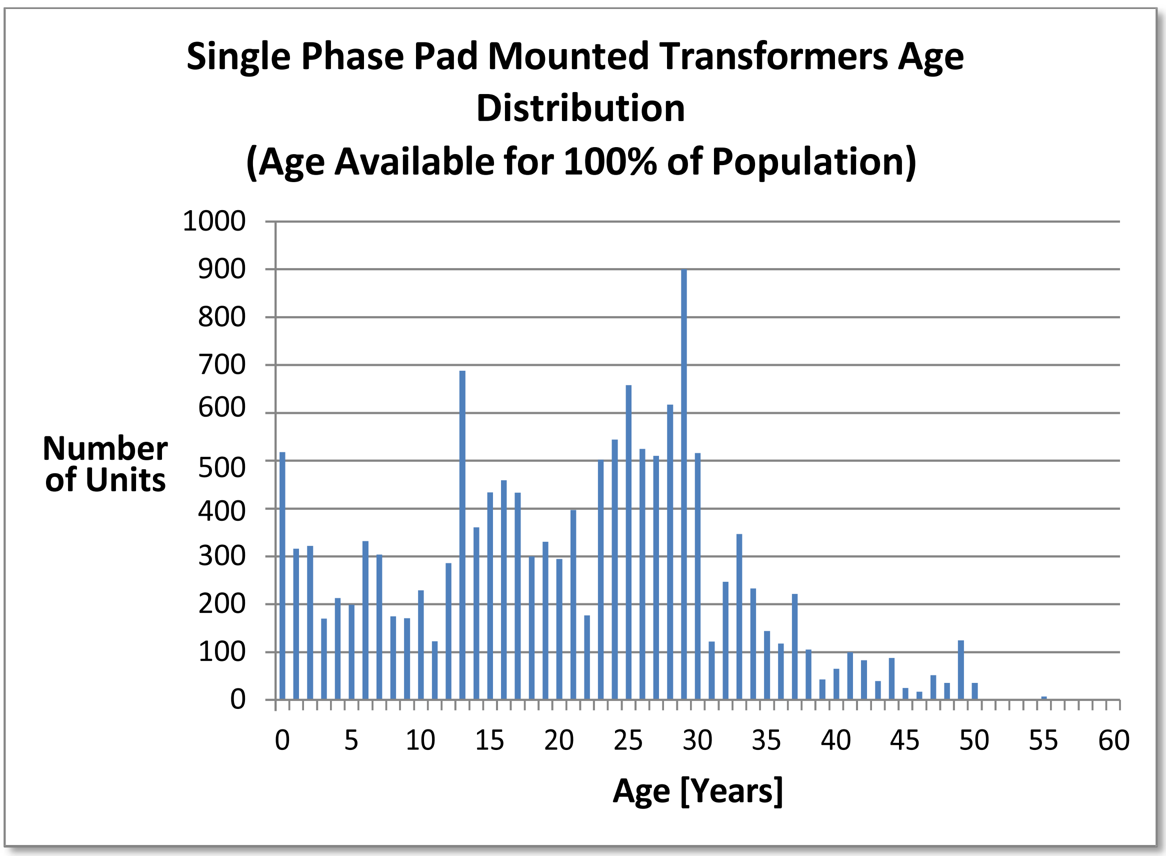


Figure 4-2 Single Phase Pad Mounted Transformers Age Distribution

Three Phase Pad Mounted Transformers

The average age of all single phase units was 16 years. Approximately 5% of the population is 35 years or older.

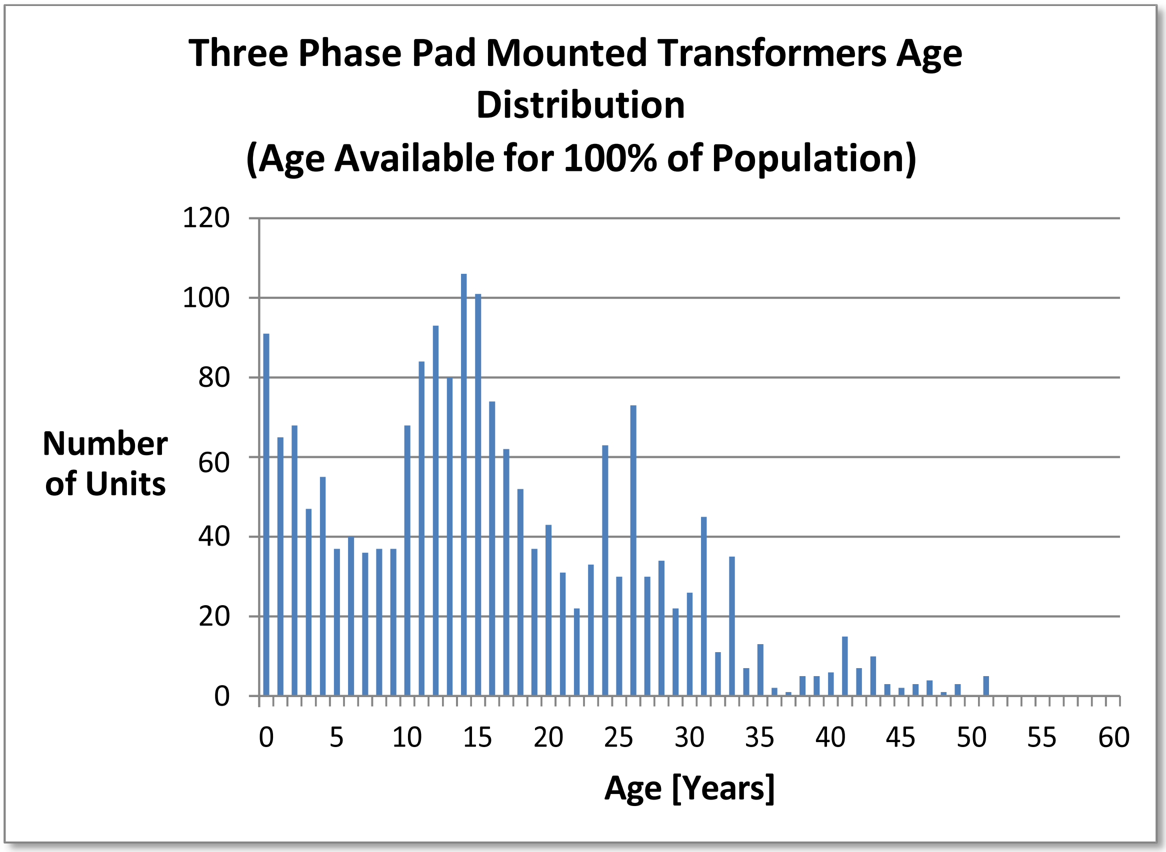


Figure 4-3 Three Phase Pad Mounted Transformers Age Distribution

4.3 Health Index Results

Single Phase Pad Mounted Transformers

There are a total of 14261 Single Phase Pad Mounted Transformers at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 86%. Approximately 6% of the population was found to be in “poor” or “very poor” condition. These include units that have PCBs and/or are leakers.

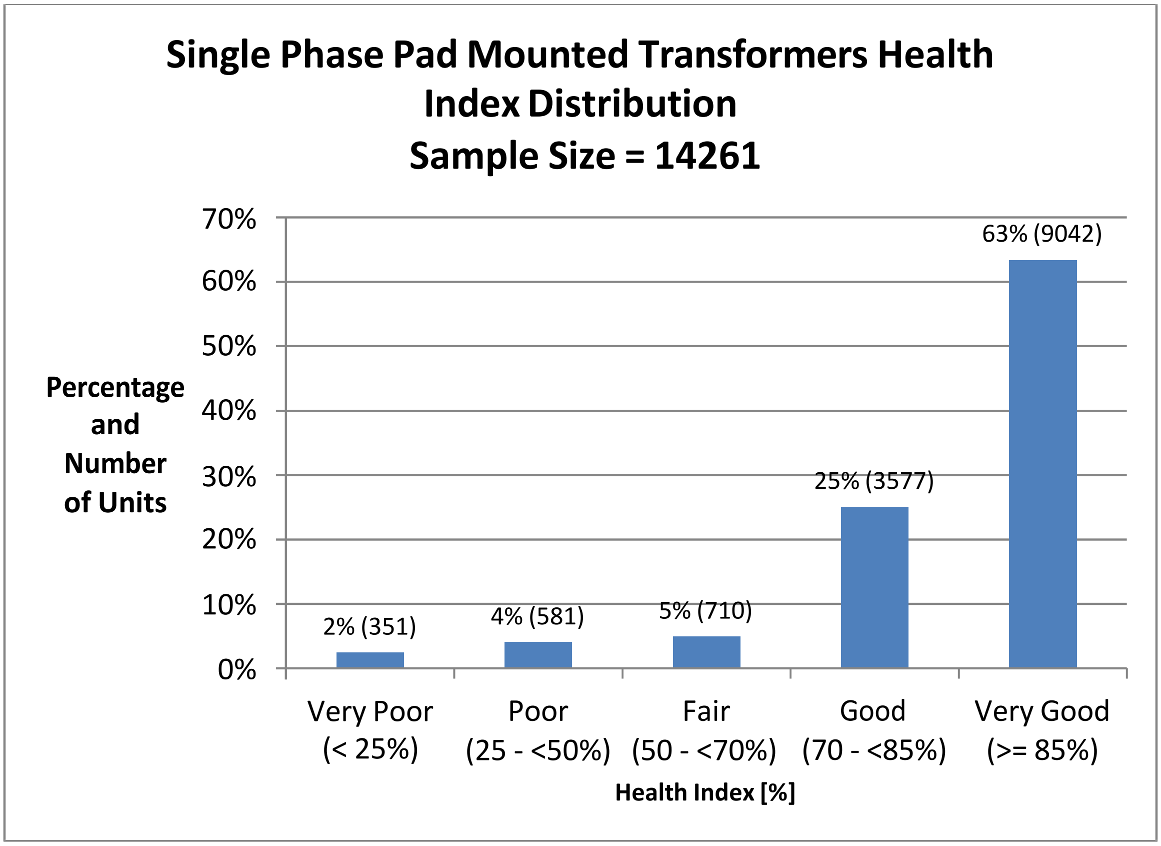


Figure 4-4 Single Phase Pad Mounted Transformers Health Index Distribution

Three Phase Pad Mounted Transformers

There are a total of 1860 Single Phase Pad Mounted Transformers at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 93%. Approximately 4% of the population was found to be in “poor” or “very poor” condition. These include units that have PCBs and/or are leakers.

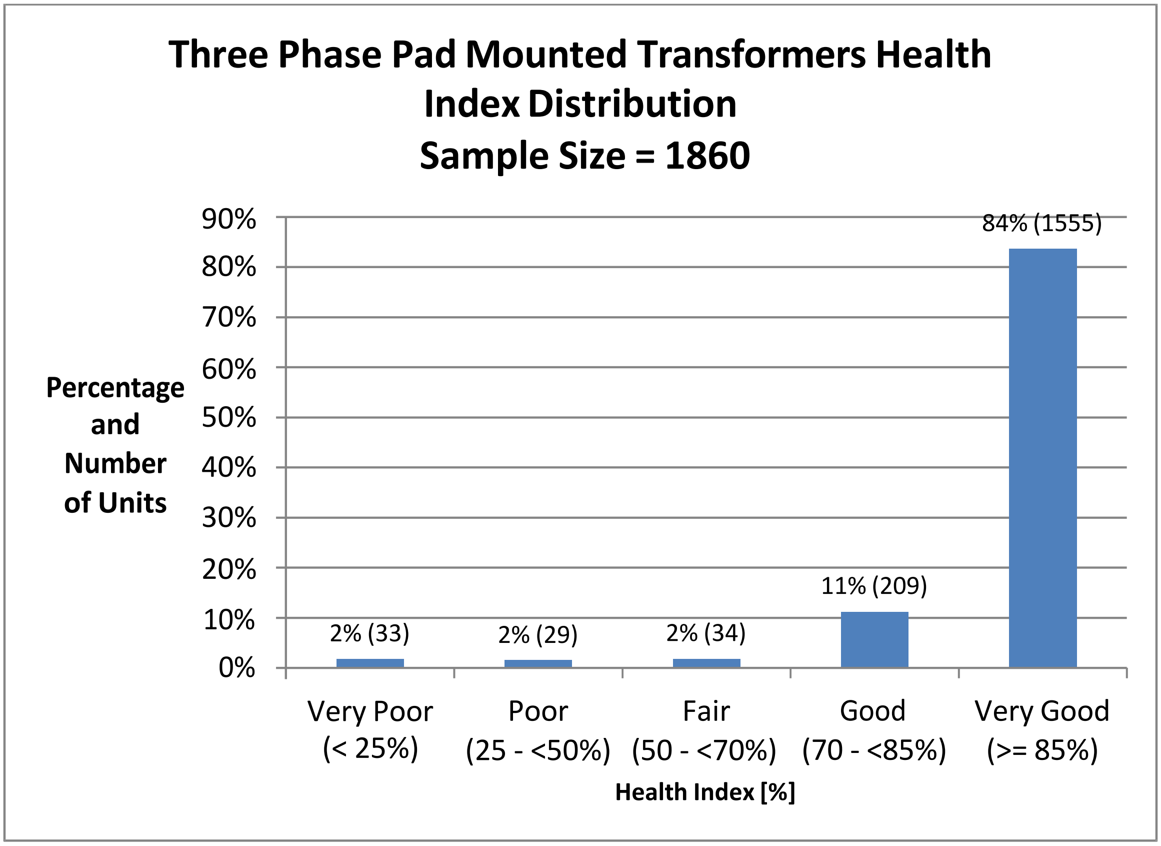


Figure 4-5 Three Phase Pad Mounted Transformers Health Index Distribution

4.4 Flagged for Action Plan

As it is assumed that Pad Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate.

Single Phase Pad Mounted Transformers

The replacment plan was as follows:

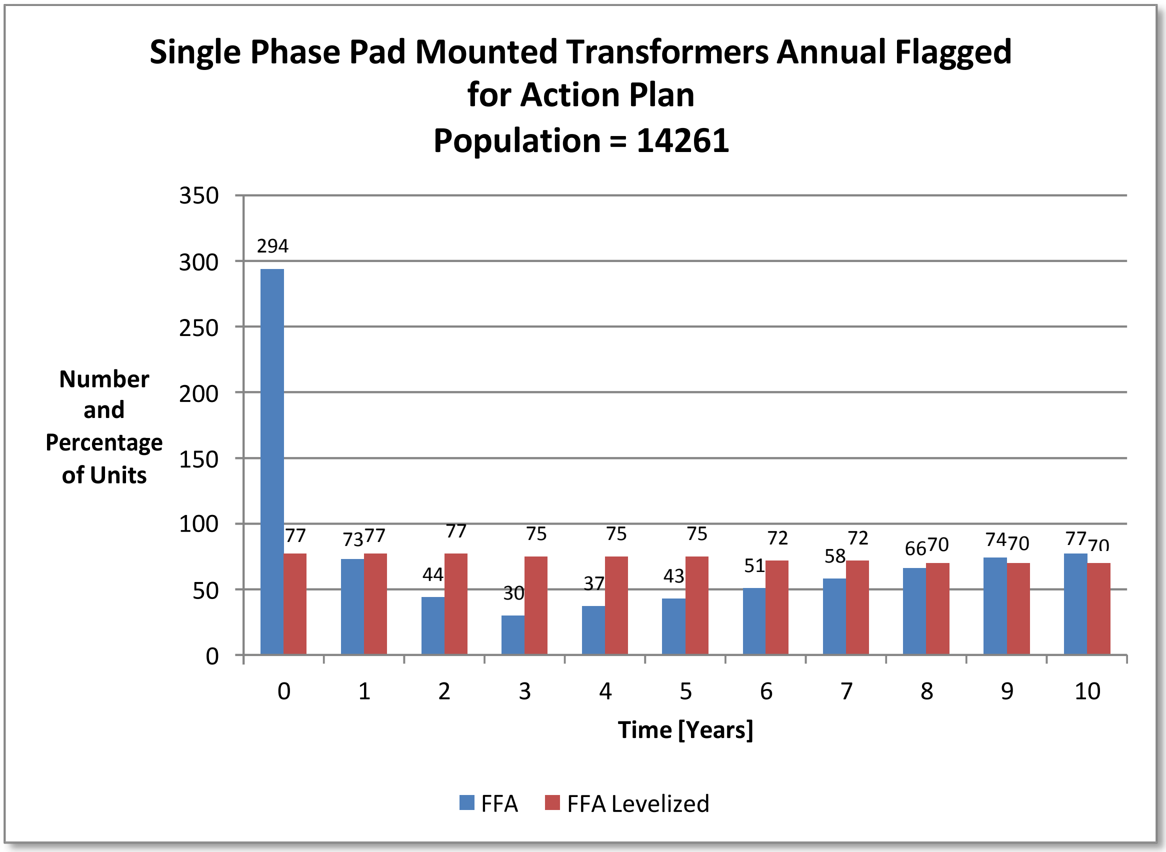


Figure 4-6 Single Phase Pad Mounted Transformers Flagged for Action Plan

Three Phase Pad Mounted Transformers

The replacment plan was as follows:

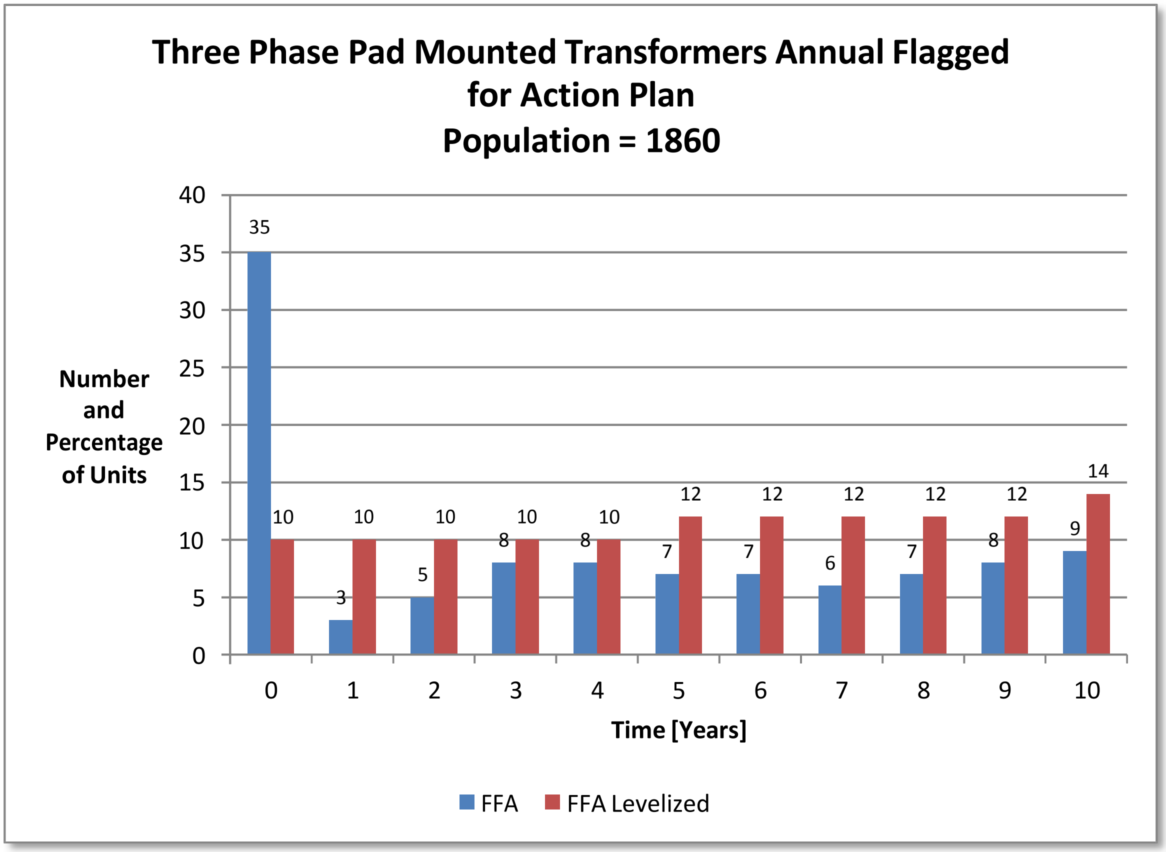


Figure 4-7 Three Phase Pad Mounted Transformers Flagged for Action Plan

4.5 Data Analysis

The average DAI of Pad Mounted Transformers has dropped from 89% to 70% for 1-phase and 70% to 68% for 3-phase year. This is because certain visual inspection information, namely access to the transformer and the condition of the foundation, was not available this year. Additionally, information about oil leak was limited. It is recommended that the access and foundation information be collected and incorporated into future assessments.

Significant improvements with respect to closing data gaps were made. Since 2014, connection (elbow) and loading have been collected and incorporated into the Health Index assessment. As such, there are no data gaps remaining for this asset.

5 VAULT TRANSFORMER

5.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	1	1	1	Enclosure	3	1	Table 5-2
				2	Access	1	1	Table 5-2
2	Connection and Insulation	1	1	1	Oil Leak	1	1	Table 5-2
				2	Connection	2	1	Table 5-2
3	Service Record	3	1	1	Overall	4	1	Table 5-2
				2	Age	3	1	Figure 5-1
				3	Oil Boil	1	1	Table 5-2
				4	Loading	4	1	Table 5-3
Overall HI De-Rating Multiplier (DR)				PCB and/or Leaker				Table 5-4
HI Maximum Limit				Overall Condition will limit maximum HI value				Table 5-5

5.1.2 Condition Criteria

__Visual Inspections__

Table 5-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 5-3 Loading History

Data: S1, S2, S3, …, SN   recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Vault Transformer exponentially increases with age and that the failure rate equation is as follows:

$$\mathbf{f} = e^{\{3(t\text{-}a)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f\text{-}e^{-a\{3})/\{3}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

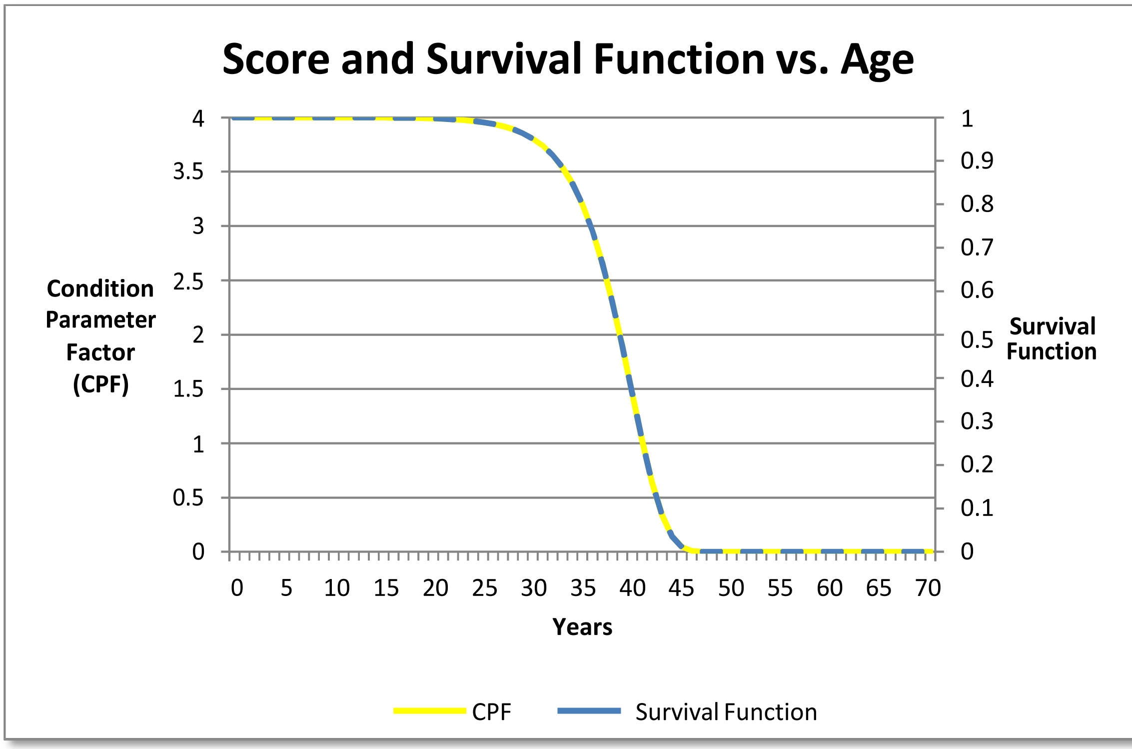


Figure 5-1 Vault Transformer Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 5-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	(PCB > 2 ppm) AND (Major Leaker)	0.1
Else if	PCB >= 50 ppm	0.1
Else if	(2 <= PCB < 50 ppm) OR (Major Leaker)	0.25
Else if	Moderate Leaker	0.7
Else		1

HI Maximum Limit

An additional Health Index limiting value is also applied. This is based on the asset's overall condition determined from Enersource's inspections. For example, if calculated HI of a certain unit is 56% (from the composite parameters) but the overall parameter score is "poor", the final HI of that asset will be limited to 50%. If the calculate HI is 38%, the final HI will be 38%.

Table 5-5 HI Maximum Limit

Overall Condition (based on Inspections)	HI Maximum Limit
VERY POOR	25%
POOR	50%
FAIR	70%

5.2 Age Distribution

The average age of all single phase units was 27 years. Approximately 23% of the population was 35 years or older.

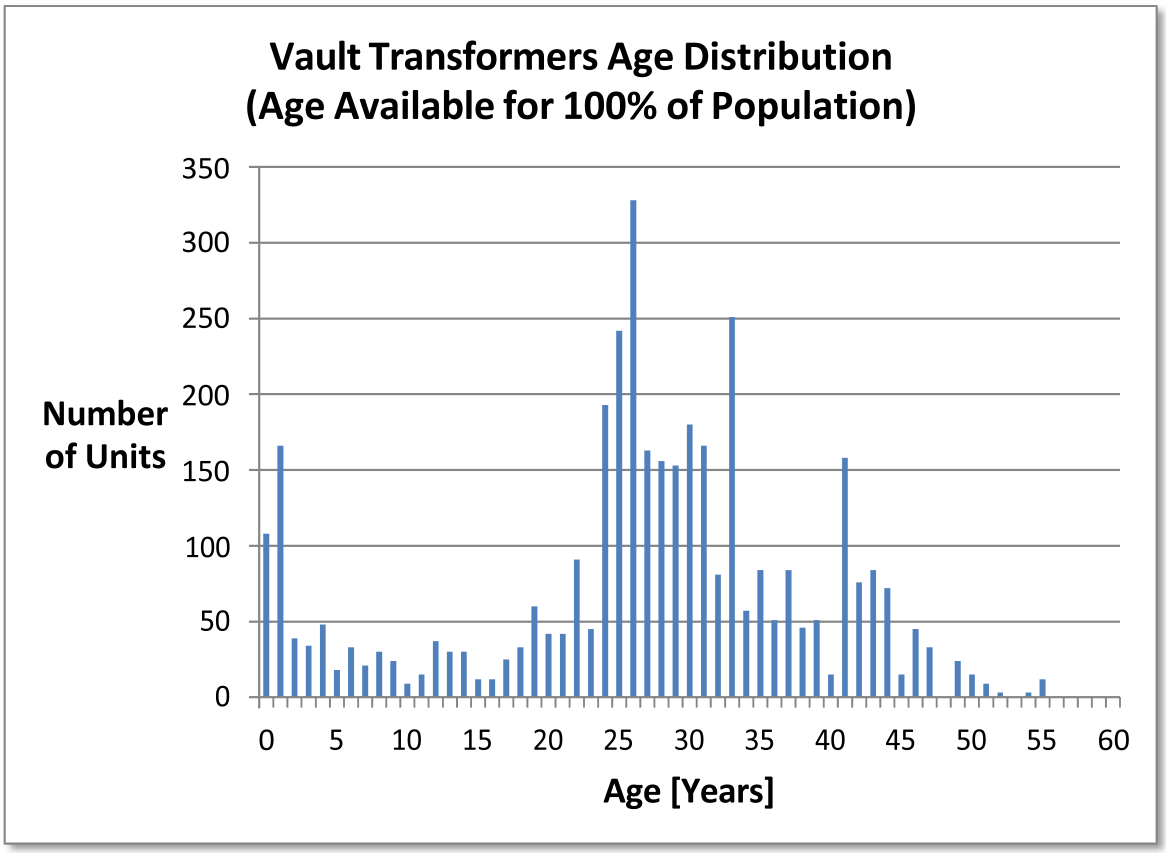


Figure 5-2 Vault Transformer Age Distribution

5.3 Health Index Results

There are 3854 Vault Transformers at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 84%. Approximately 11% of the population was in "poor" or "very poor" condition. These include units that have PCBs and/or are leakers.

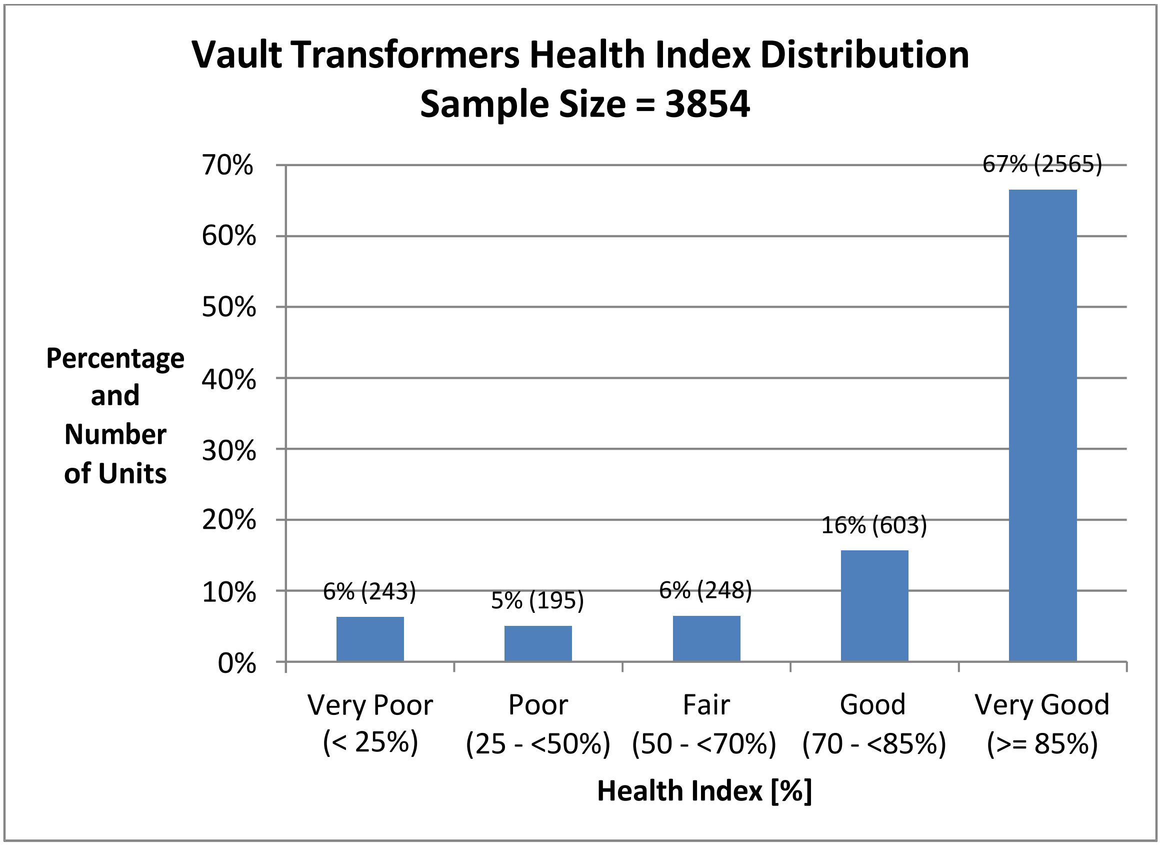


Figure 5-3 Vault Transformer Health Index Distribution

5.4 Flagged for Action Plan

As it is assumed that Vault Transformer were reactively replaced, the flagged for action plan was based on the asset failure rate.

The Flagged for Action Plan was as follows:

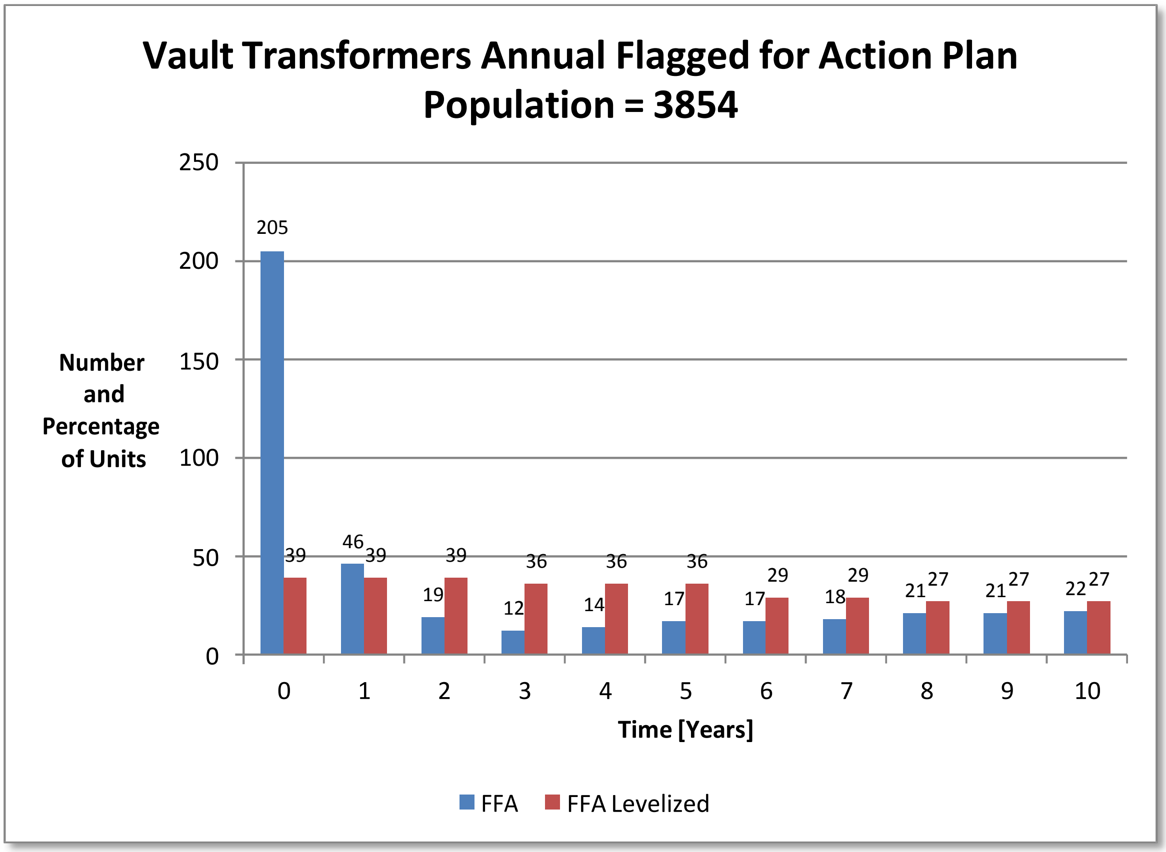


Figure 5-4 Vault Transformer Flagged for Action Plan

5.5 Data Analysis

The average DAI of Vault Transformers has improved from 78% to 88% this year. Significant improvements with respect to closing data gaps were the collection and incorporation of bushing and loading information. No data gaps remaining for this asset.

6 PAD MOUNTED SWITCHGEAR

6.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

6.1.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Parameter and Weights

Condition Parameter (CP)						Sub-Condition Parameter (SCP)						
n	Description	Weight (WCP) Switchgear	Weight (WCP) SF6	Weight (WCP) Solid Dielectric	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP) Switchgear	Weight (WSCP) SF6	Weight (WSCP) Solid Dielectric	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Physical Condition	4	4	2	1	1	Corrosion	6	6	6	1	Table 6-2
						2	Paint	3	3	3	1	Table 6-2
						3	Door/Hinge	1	1	1	1	Table 6-2
						4	Foundation	3	3	3	1	Table 6-2
						5	Access	1	1	1	1	Table 6-2
						6	Debris	1	1	1	1	Table 6-2
						7	Excess Moisture	1	1	1	1	Table 6-2
2	Switch/Fuse	1	1	0	1	1	Arc Suppressor	1	1	0	1	Table 6-2
3	Connection	2	2	1	1	1	Connections/ Elbow	1	1	1	1	Table 6-2
						2	Termination	1	1	1	1	Table 6-2
						3	Hotspots	1	1	1	1	Table 6-2
						4	Tracking	2	2	2	1	Table 6-2
						5	Grounding	1	1	1	1	Table 6-2
4	Insulation	2	2	1	1	1	Insulator	1	1	1	1	Table 6-2
						2	Board	1	1	1	1	Table 6-2
						3	SF6 Leak	0	1	0	1	Table 6-2
5	Service Record	4	4	2	1	1	Overall	2	2	2	1	Table 6-2
						2	Age	1	1	1	1	Figure 6-1
Overall HI De-Rating Multiplier (DR)						Rust, Tracking, Poor Foundation						
HI Maximum Limit						Overall Condition will limit maximum HI value						

6.1.2 Condition Criteria

Visual Inspections

Table 6-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate Pad Mounted Switchgear exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 25 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

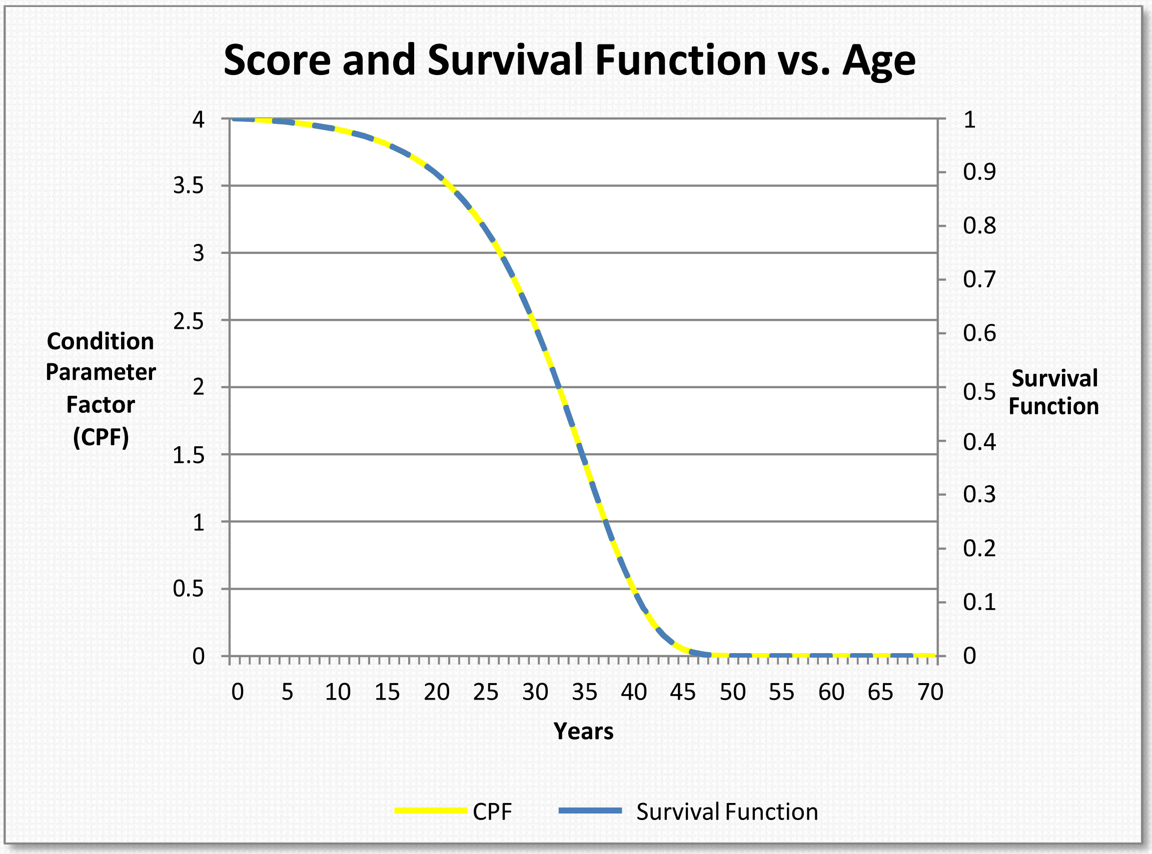


Figure 6-1 Pad Mounted Switchgear Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units have major rust, major tracking, or a combination of minor rust, tracking, and poor foundation.

Table 6-3 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	(Major Rust) or (Major Tracking)	0.25
Else if	(Minor Rust) and (Minor Tracking) and (Poor Foundation)	0.25
Else		1

HI Maximum Limit

An additional Health Index limiting value is also applied. This is based on the asset's overall condition determined from Enersource's inspections. For example, if calculated HI of a certain unit is 56% (from the composite parameters) but the overall parameter score is "poor", the final HI of that asset will be limited to 50%. If the calculate HI is 38%, the final HI will be 38%.

Table 6-4 HI Maximum Limit

Overall Condition (based on Inspections)	HI Maximum Limit
VERY POOR	25%
POOR	50%
FAIR	70%

6.2 Age Distribution

The average age of all units was 15 years. Approximately 23% of the population was 25 years or older.

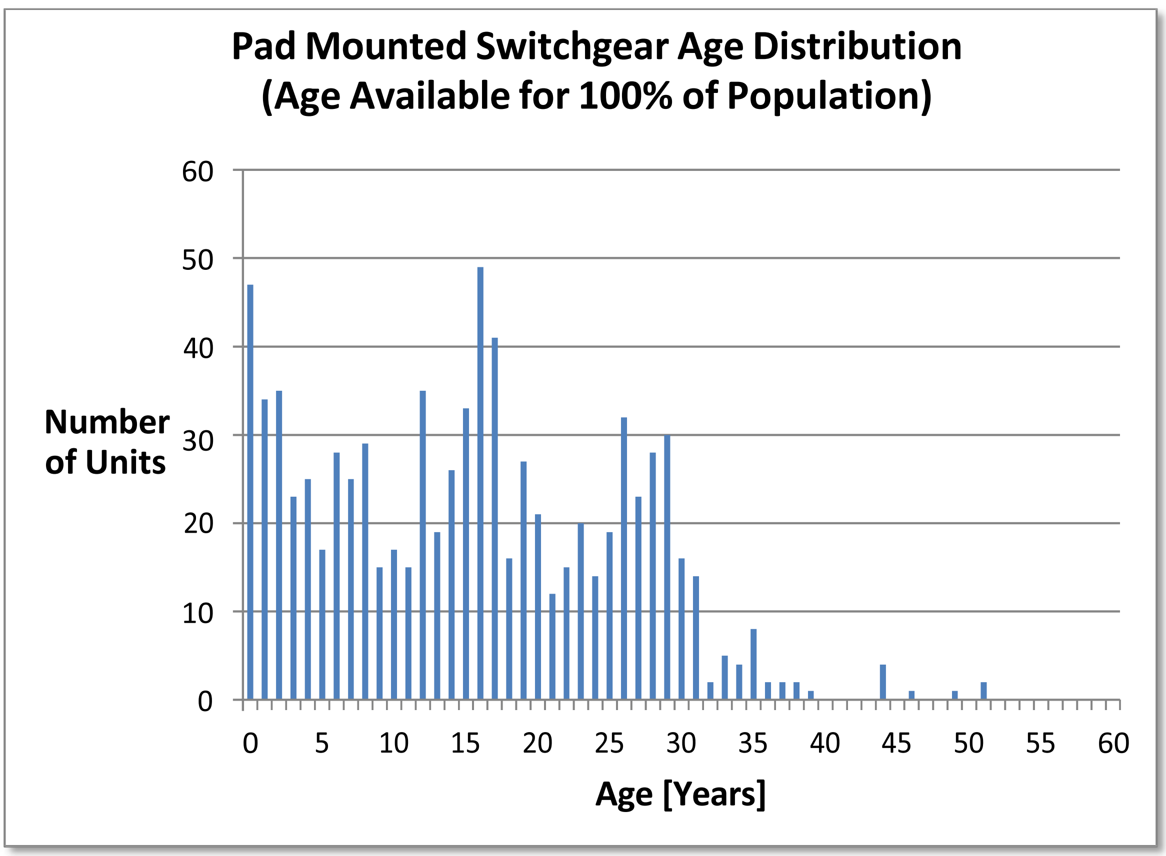


Figure 6-2 Pad Mounted Switchgear Age Distribution

6.3 Health Index Results

There are 834 Pad Mounted Switchgear at Enersource. Of these, there are 834 units with sufficient data for Health Indexing.

The average Health Index for this asset group was 88%. About 8% of the population was in "poor" or "very poor" condition.

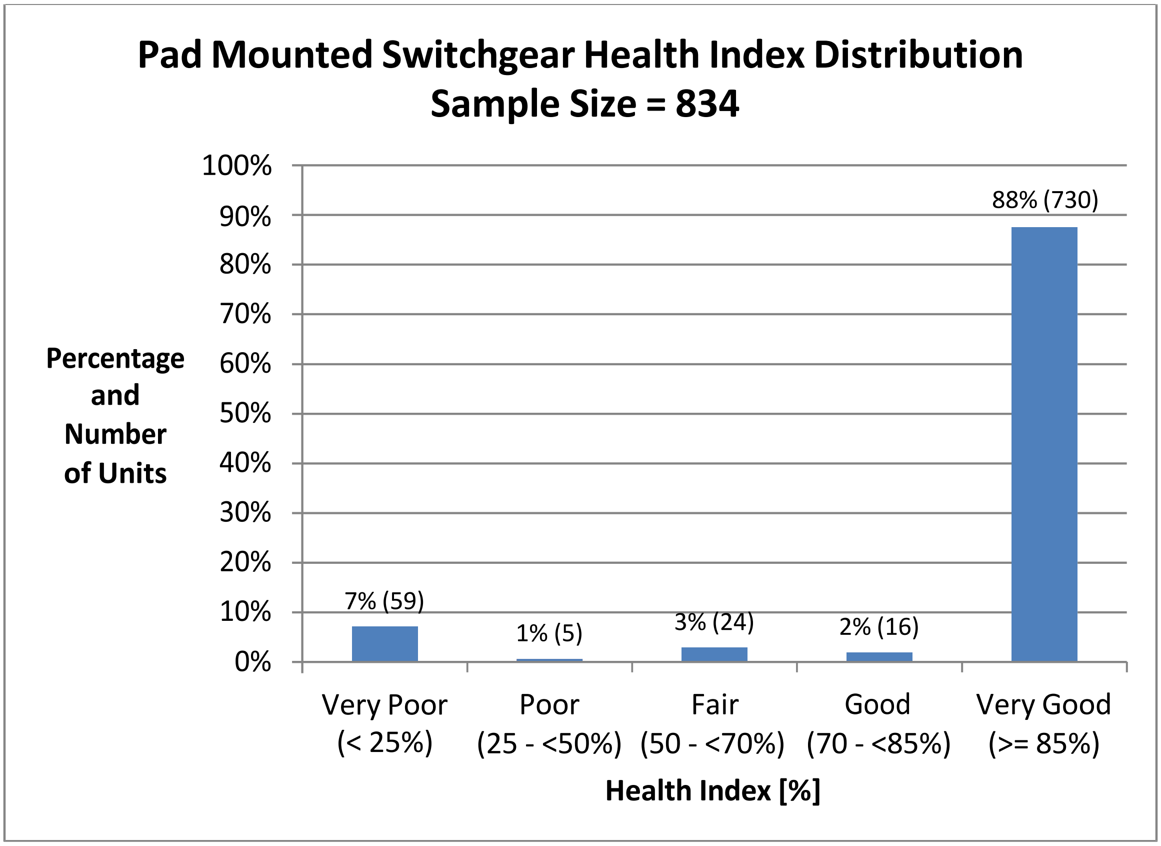


Figure 6-3 Pad Mounted Switchgear Health Index Distribution

6.4 Flagged for Action Plan

As it is assumed that Pad Mounted Switchgear were reactively replaced, the flagged for action plan was based on the asset failure rate.

The Flagged for Action Plan was as follows:

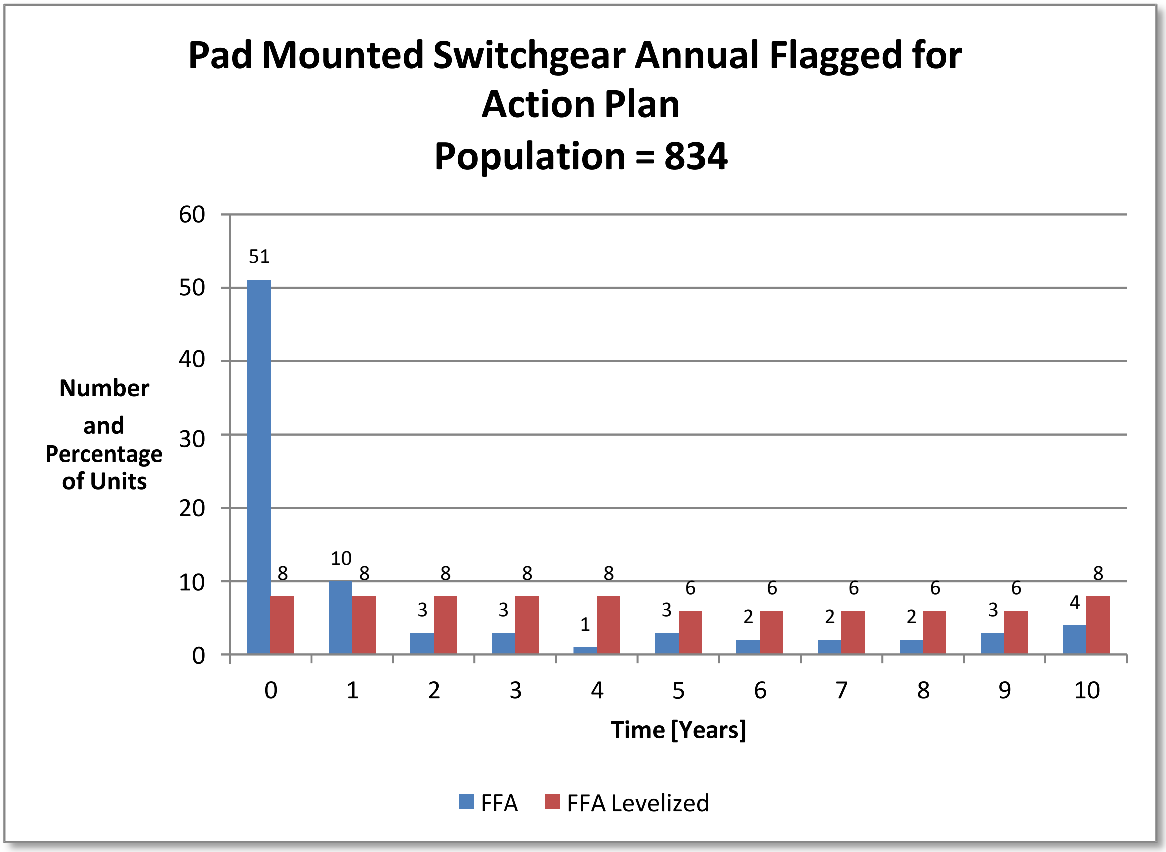


Figure 6-4 Pad Mounted Switchgear Flagged for Action Plan

6.5 Data Analysis

The average Pad Mounted Switchgear DAI improved significantly from 39% in 2014 to 89% in 2015. This is because of a significant increase in the availability of inspection information. In 2014 only half of the population had inspection records; in 2015 93% of the switchgear population was inspected. There are no data gaps for this asset.

7 Overhead Line Switches

This study includes four sub-categories of overhead line switches: 44 kV, 27.6 kV, Inline, and Motorized.

7.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.1.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Operating Mechanism	**4**	**1**	1	Operations Record	1	**1**	Table 7-3
2	Contact Performance	**3**	**1**	1	Switch Blade	1	**1**	Table 7-2
3	Insulation	**2**	**1**	1	Insulator	1	**1**	Table 7-2
4	Service Record	**4**	**1**	1	Age	**1**	**1**	Figure 7-1 Figure 7-2

7.1.2 Condition Criteria

<u>Operations Record</u>

Table 7-2 Operations Records Criteria

Score	Condition Description
4	Operated in Last Year
3.5	Operated in Last 3 Years
3	Operated in Last 5 Years
0	Not Operated in Last Year

Visual Inspections

Table 7-3 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

$$\mathbf{f} = e^{\{3(t\text{-}a)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f\text{-}e^{-a\{3})/\{3}}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for 27.6 kV, 44 kV, and Inline Switches are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

For motorized switches, the ages of 25 and 35 are used.

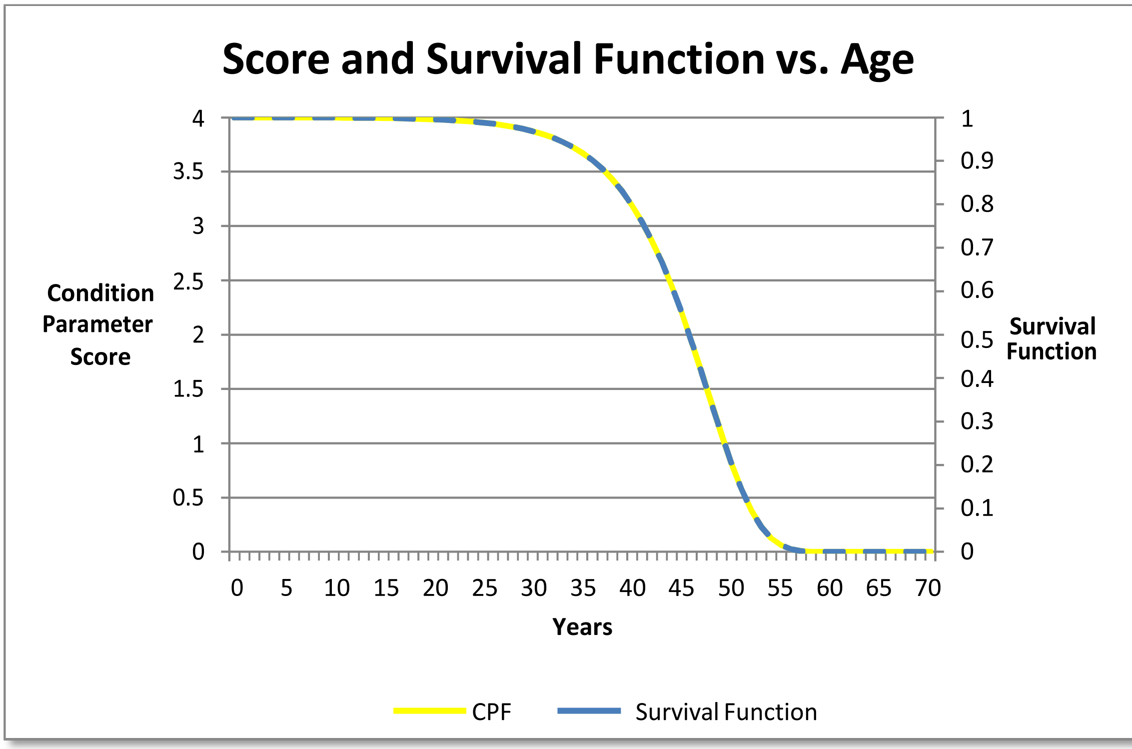


Figure 7-1 Overhead Line Switches Age Criteria (Non-Motorized and Inline)

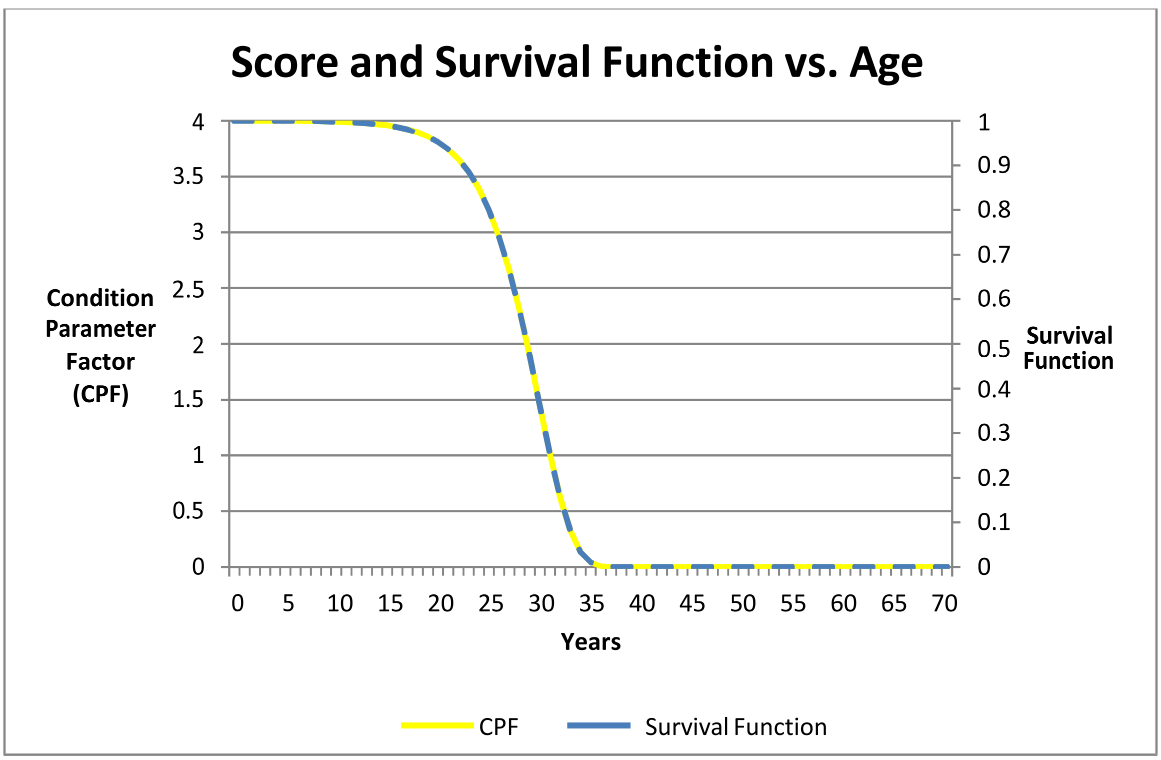


Figure 7-2 Overhead Line Switches Age Criteria (Motorized)

7.2 Age Distribution

44 kV Load Break Switches

The average age of all units was 21 years. Approximately 10% of the population was 40 years or older.

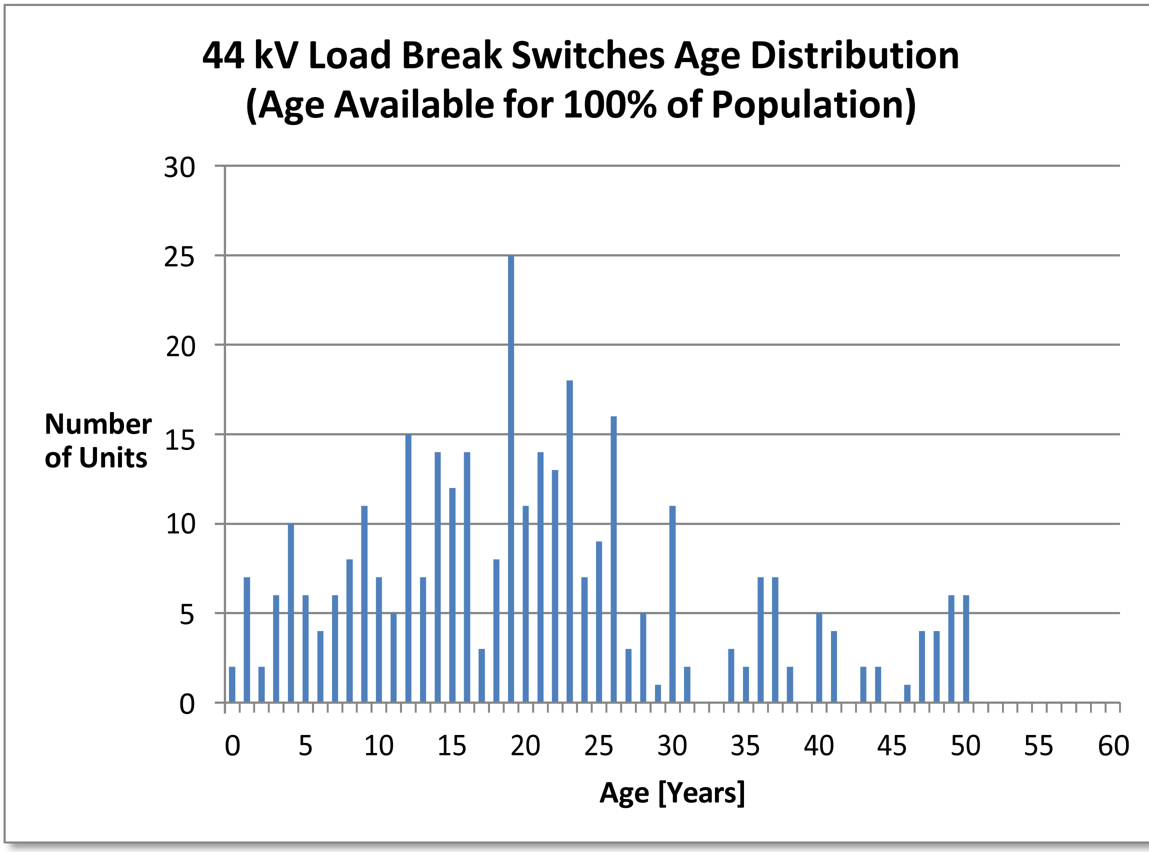


Figure 7-3 44 kV Load Break Switches Age Distribution

27.6 kV Load Break Switches

The average age of all units was 19 years. Approximately 6% of the population was 40 years or older.

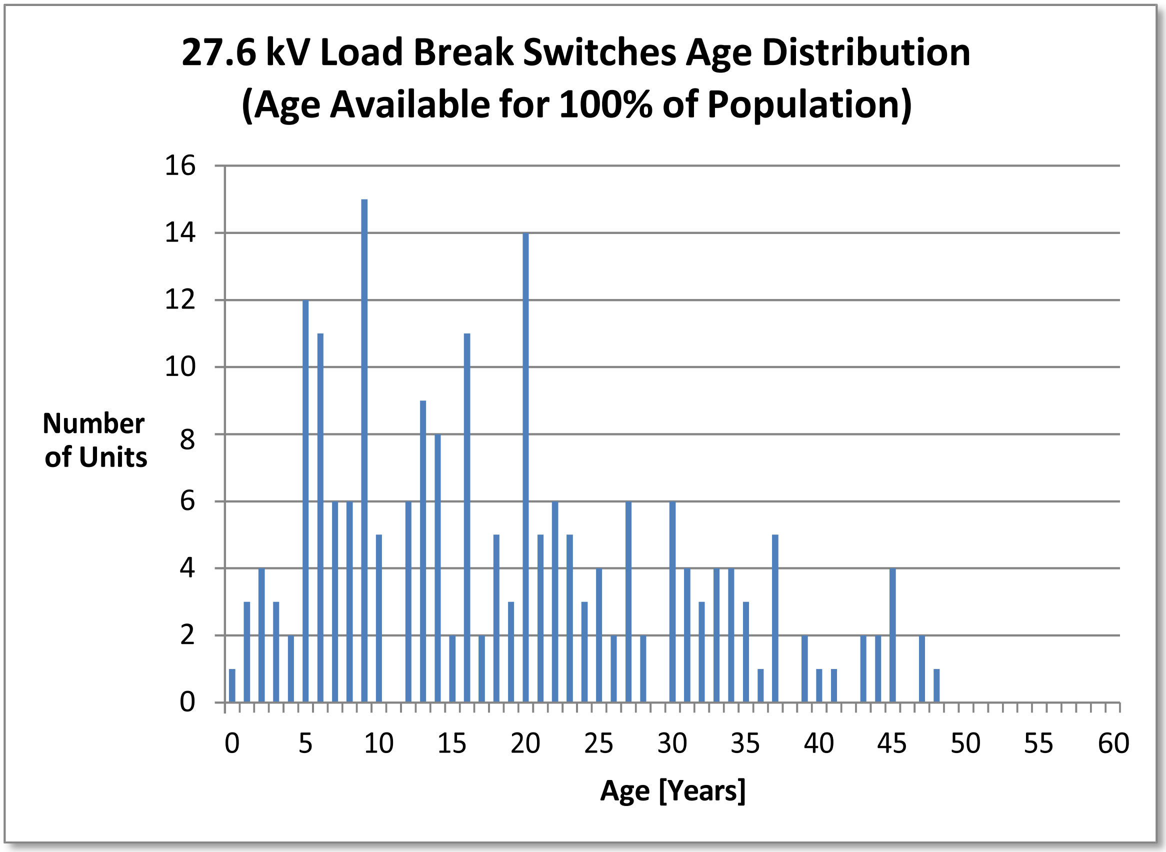


Figure 7-4 27.6kV Load Break Switches Age Distribution

In-Line Switches

The average age of all units was 18 years. Approximately 16% of the population was 40 years or older.

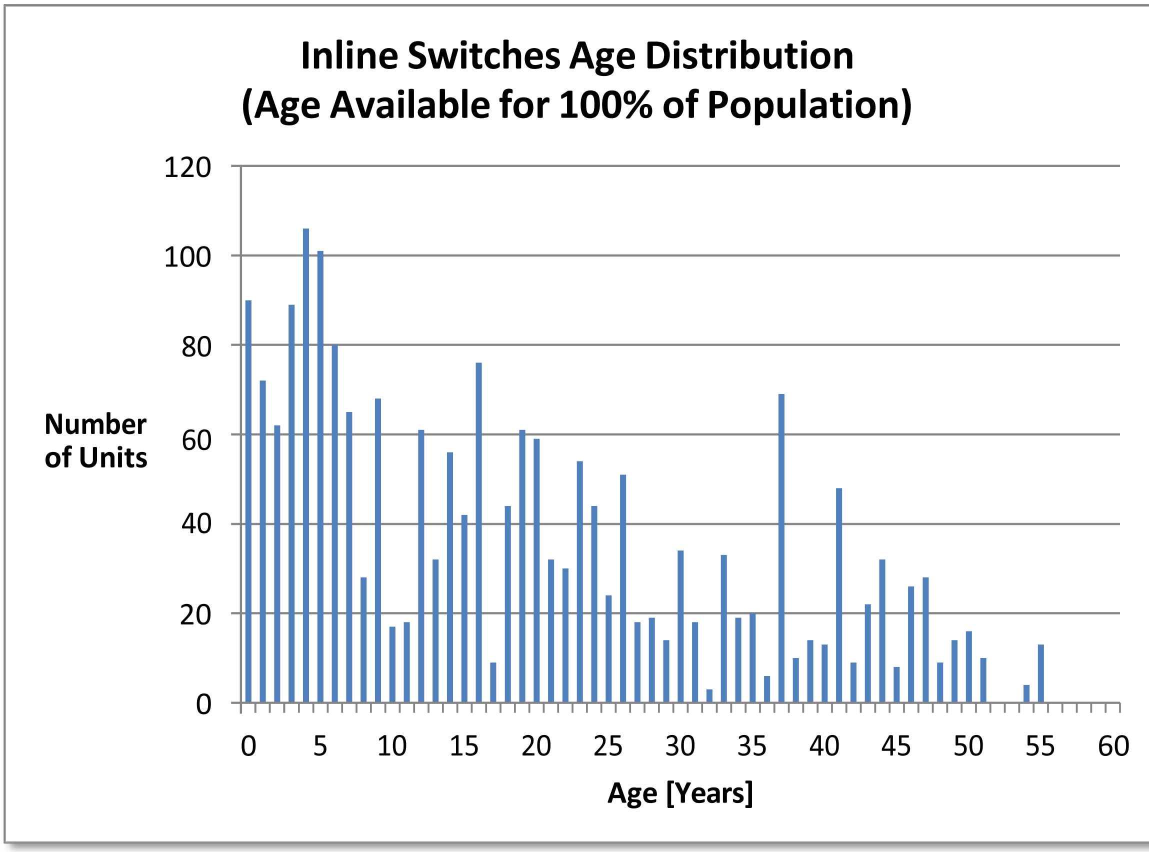


Figure 7-5 In-Line Switches Age Distribution

Motorized Switches

The average age of all units was 15 years. Approximately 25% of the population was 25 years or older.

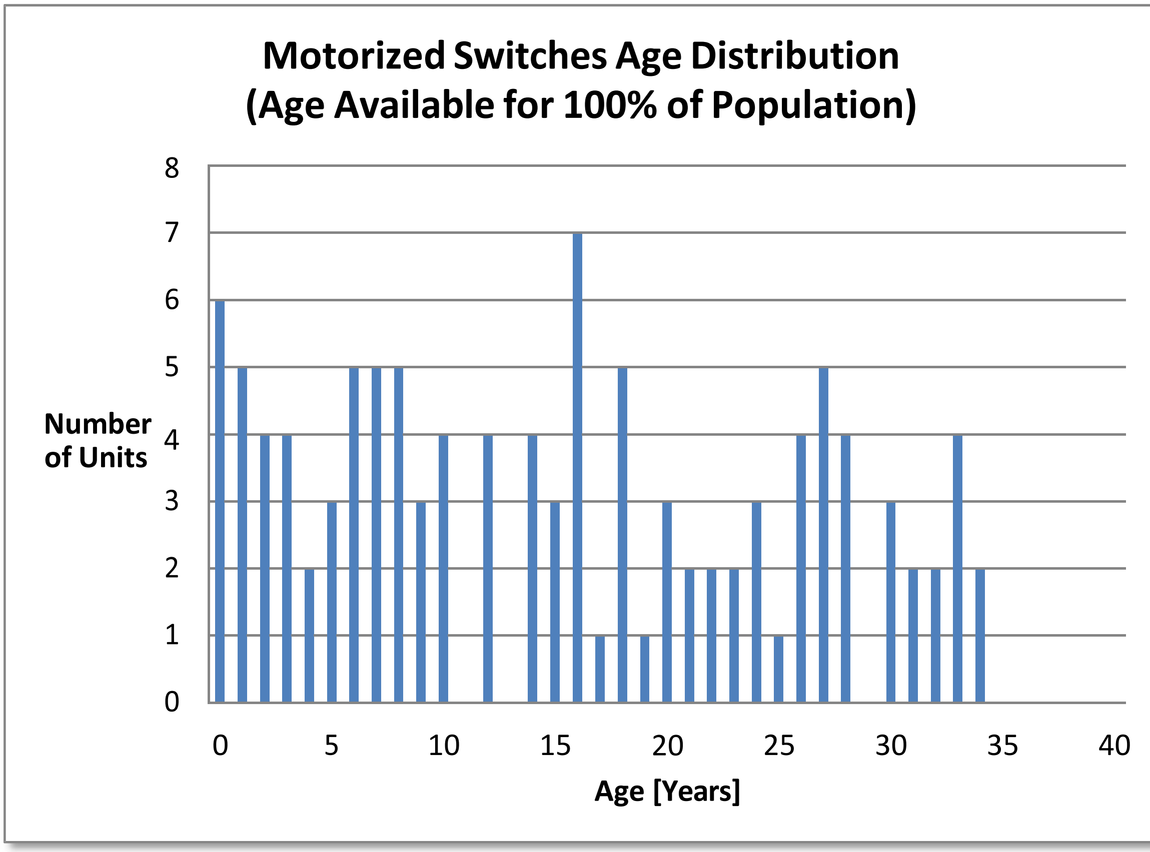


Figure 7-6 Motorized Switches Age Distribution

7.3 Health Index Results

44 kV Load Break Switches

There are 337 *44 kV Load Break Switches* at Enersource. Of these, all units had sufficient data for Health Indexing.

The average Health Index for this asset group was 89%. Approximately 2% were in “poor” or “very poor” condition.

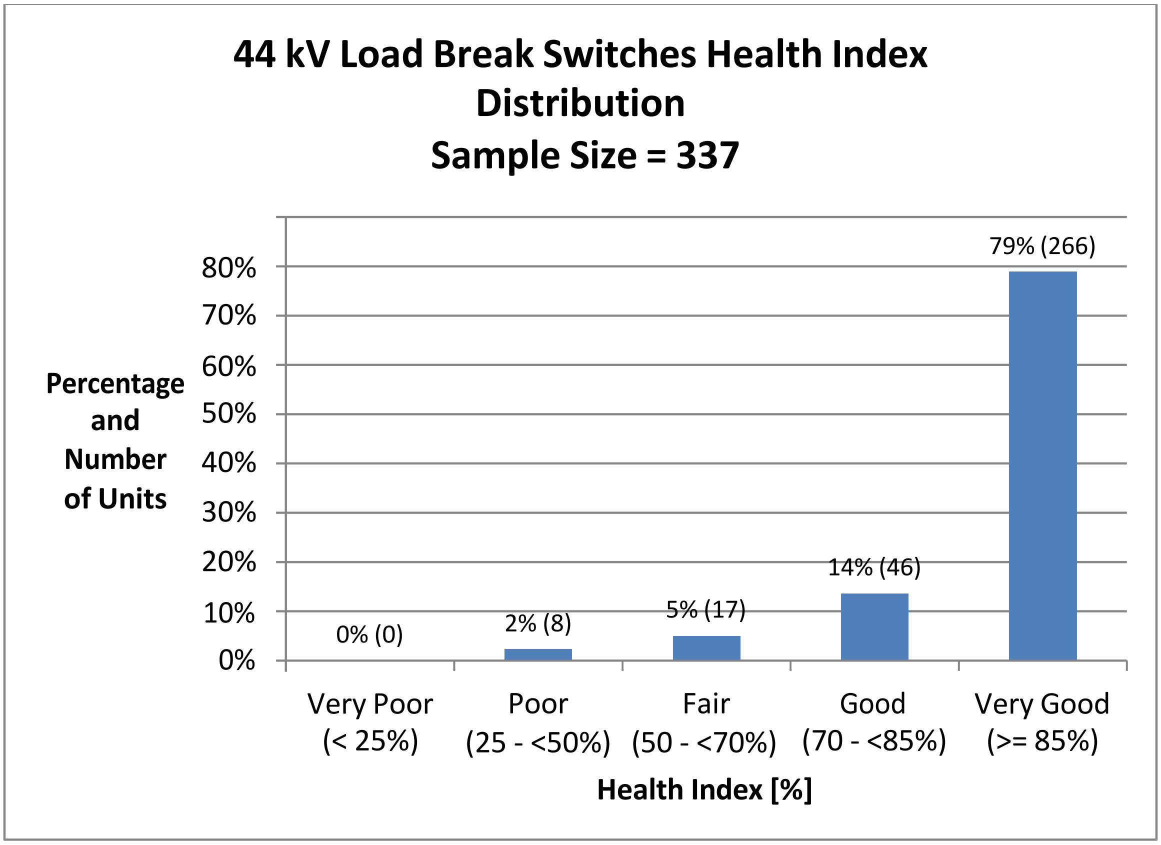


Figure 7-7 44 kV Load Break Switches Health Index Distribution

27.6 kV Load Break Switches

There are 206 *27.6 kV Load Break Switches* at Enersource. Of these, all units had sufficient data for Health Indexing.

The average Health Index for this asset group was 89%. Approximately 2% were in "poor" or "very poor" condition.

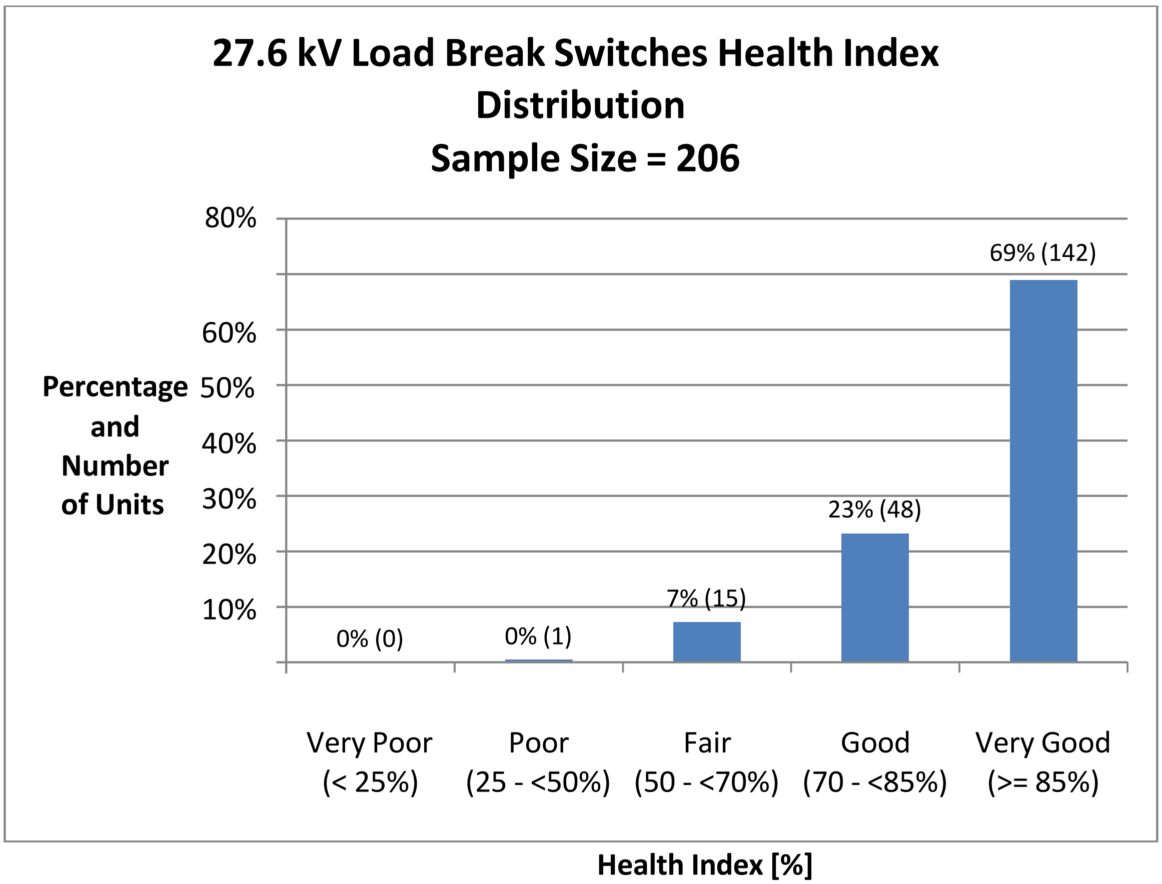


Figure 7-8 27.6kV Load Break Switches Health Index Distribution

In Line Switches

There are 206 *In Line Switches* at Enersource. Of these, all units had sufficient data for Health Indexing.

The average Health Index for this asset group was 82%. Approximately 4% were in "poor" or "very poor" condition.

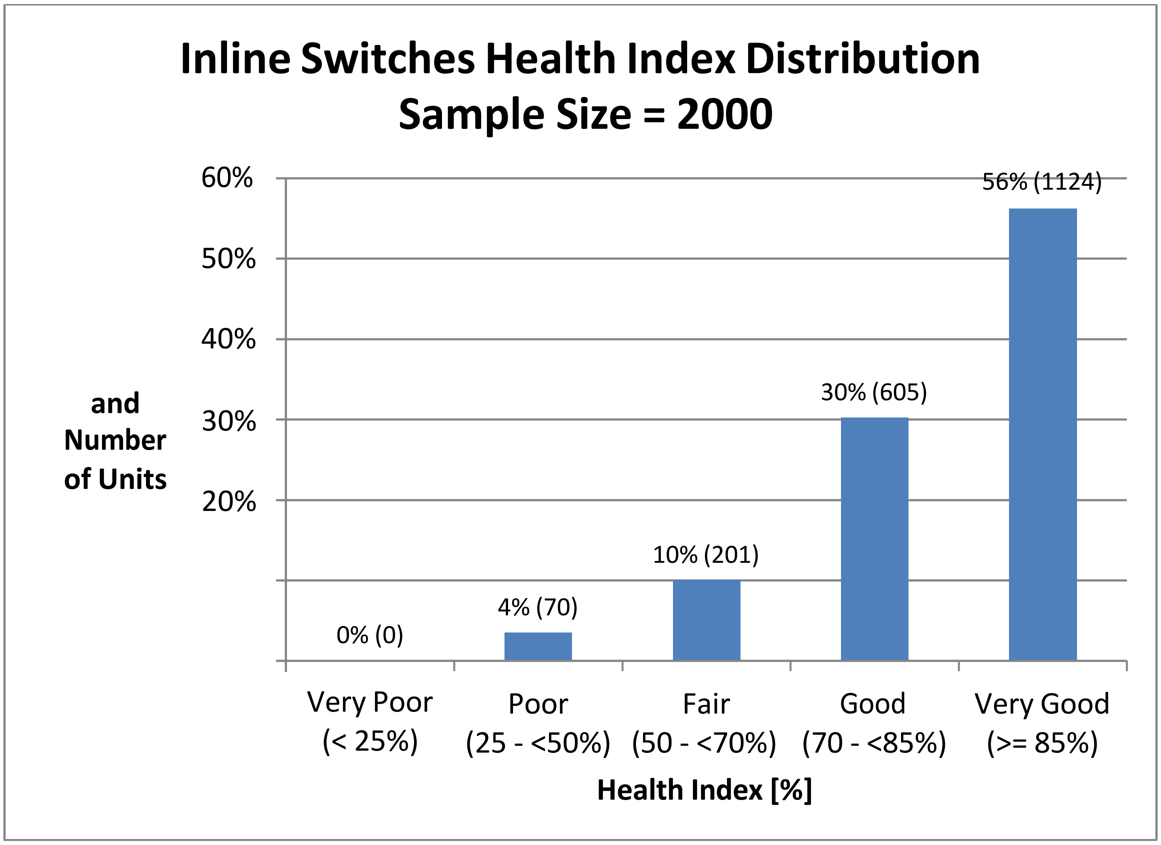


Figure 7-9 In Line Switches Health Index Distribution

Motorized

There are 110 *Motorized* at Enersource. Of these, all units had sufficient data for Health Indexing.

The average Health Index for this asset group was 90%. Approximately 2% were in “poor” or “very poor” condition.

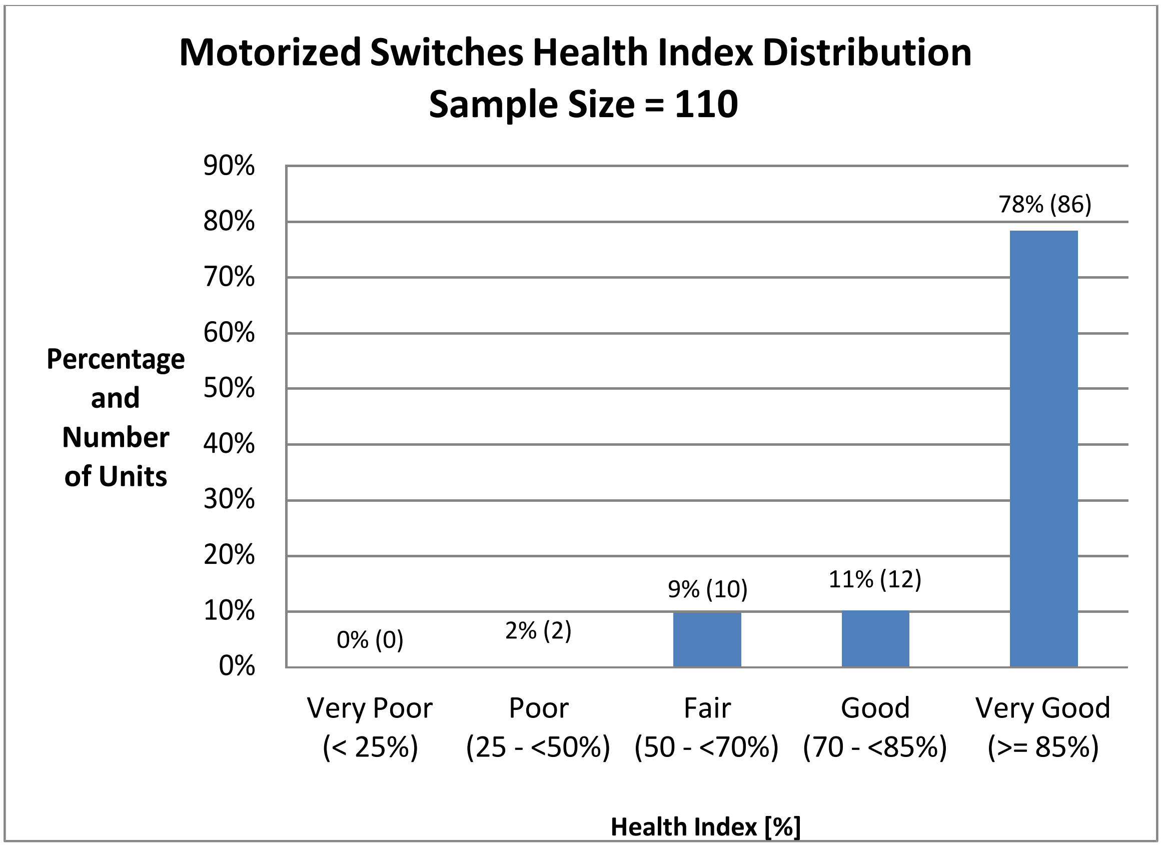


Figure 7-10 Motorized Switches Health Index Distribution

7.4 Flagged for Action Plan

As it is assumed that Overhead Line Switches were reactively replaced, the flagged for action plan was based on the asset failure rate.

The Flagged for Action Plan was as follows:

44 kV Load Break Switches

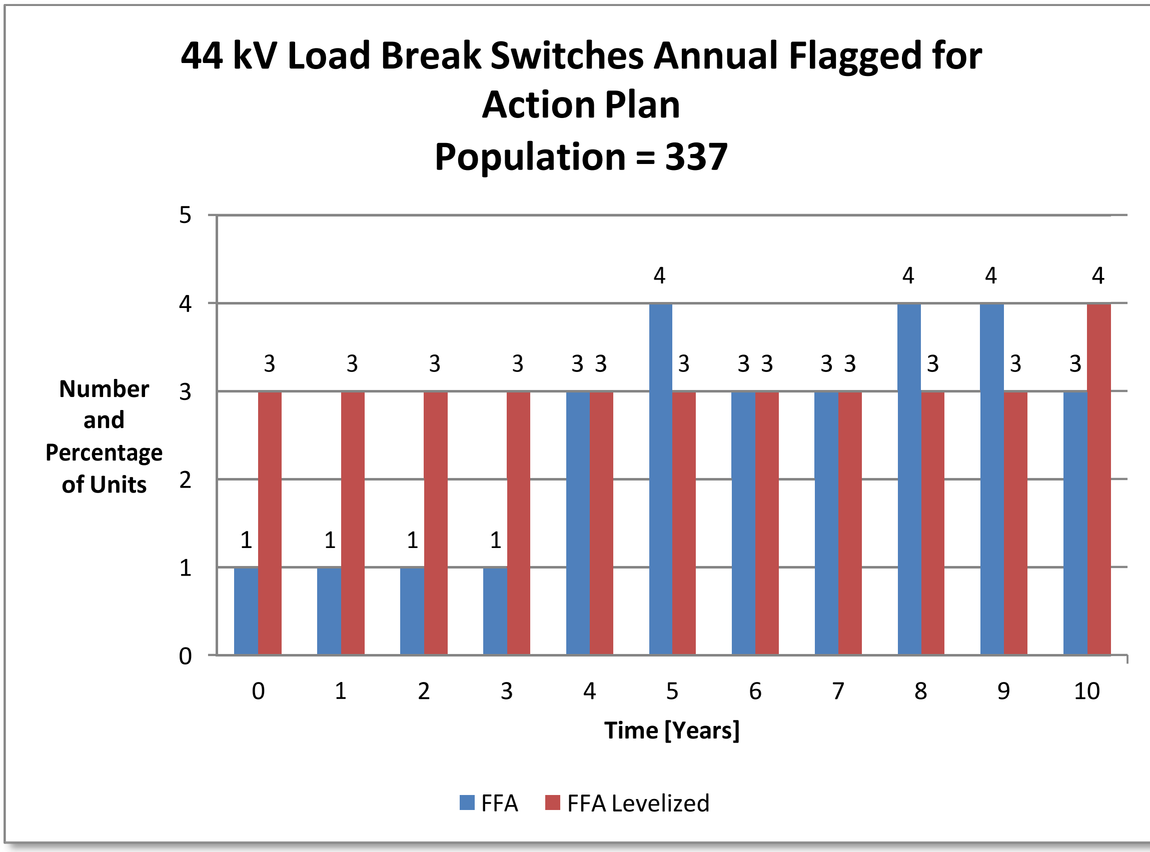


Figure 7-11 44 kV Load Break Switches Flagged for Action Plan

27.6 kV Load Break Switches

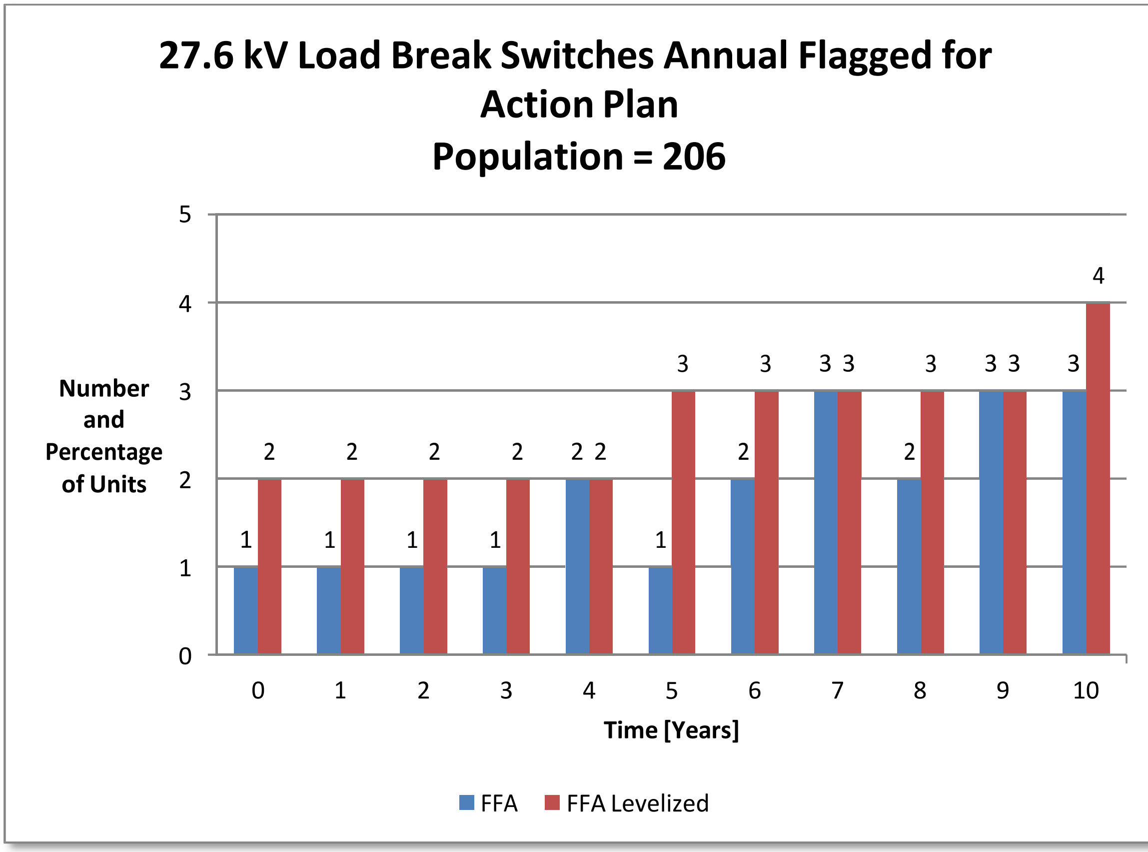


Figure 7-12 27.6kV Load Break Switches Flagged for Action Plan

In Line Switches

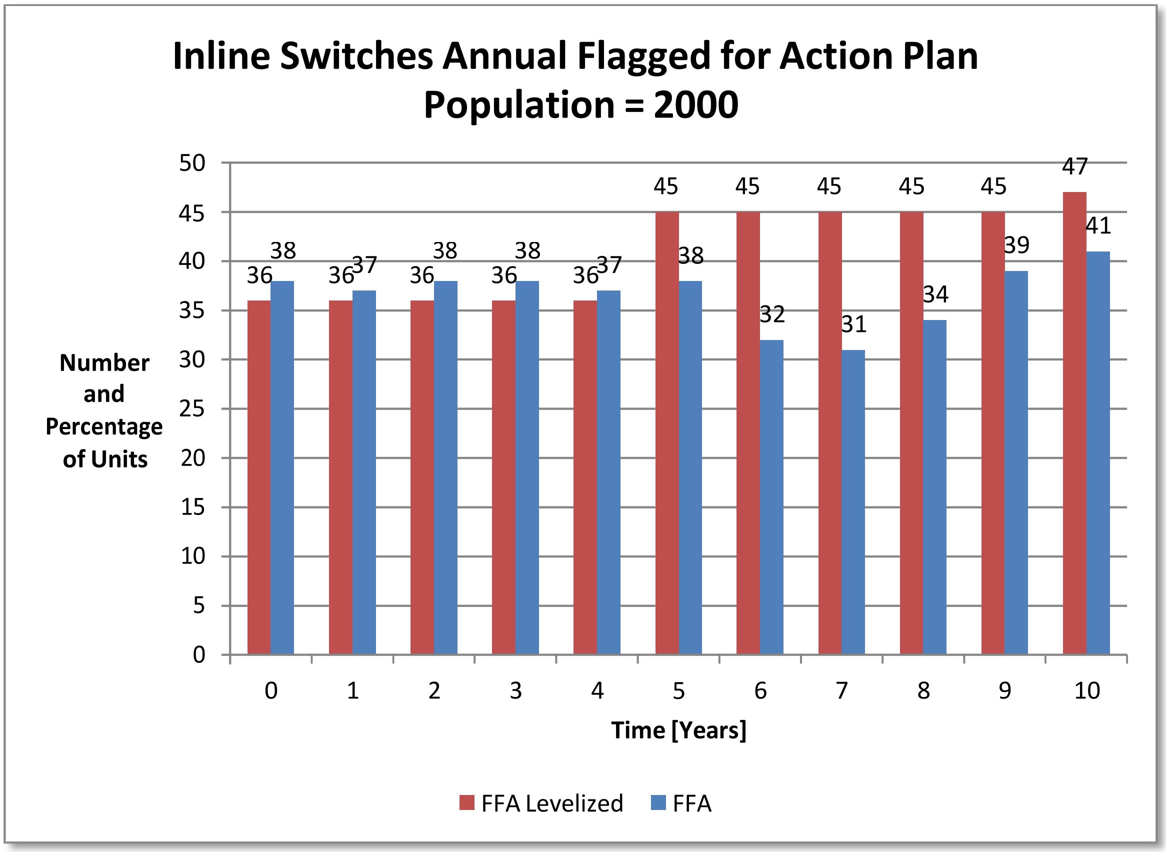


Figure 7-13 In Line Switches Flagged for Action Plan

Motorized Switches

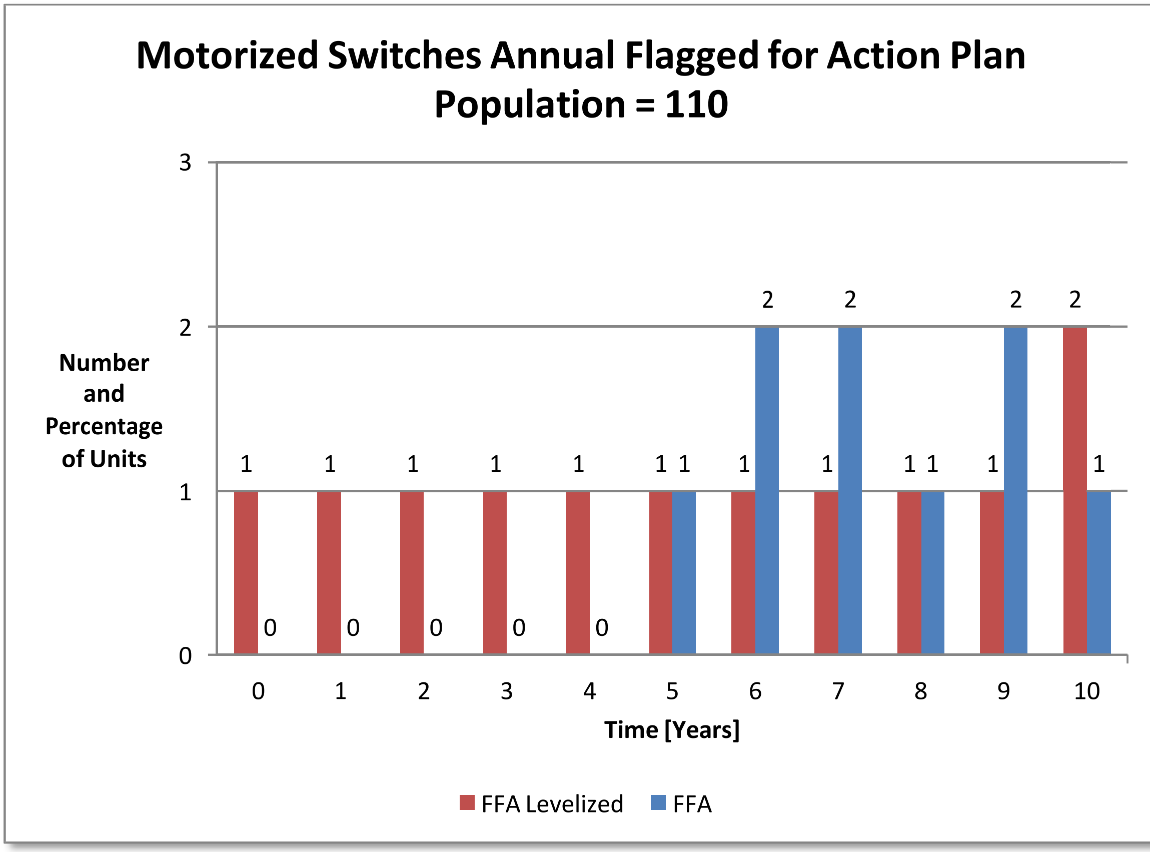


Figure 7-14 Motorized Flagged for Action Plan

7.5 Data Analysis

While the DAI of Overhead Switches appeared to have increased, it should be noted that only age and an indication of whether a switch has been operated in recent years is available.

Condition information, e.g. switch condition, insulator condition, and arc extinction information, have yet to be collected for this asset group. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	+++	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection
Mechanical Support		+	Switch support	Loose installation	On-site visual inspection
Arc Horn	Arc Extinction	+	Switch operation	Arc horn surface worn-out	On-site visual inspection
Arc Interrupter		++	Switch arc extinction	Arc extinction part surface worn-out	On-site visual inspection
Insulator	**Insulation**	+	Support insulator	Crack	On-site visual inspection
Switch Condition	**Service Record**	+++	Blade	Blade condition	On-site visual inspection

8 UNDERGROUND PRIMARY CABLES

8.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

8.1.1 Condition and Sub-Condition Parameters

Table 8-1 Condition Parameter and Weights

Condition Parameter (CP)				**Sub-Condition Parameter (SCP)**				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Descriptio n**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Service Record	**1**	**1**	1	Age	**1**	**1**	Figure 8-1 Figure 8-2
Overall HI De-Rating Multiplier (DR)				Number of Failures in last 5 Years				Table 8-2

8.1.2 Condition Criteria

8.1.2.1 Age

Assume that the failure rate Underground Primary Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\{3(t-a)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-a\{3})/\{3}}$$

S_f = survivor function
P_f = cumulative probability of failure

All the underground cables in this study are of XLPE type. There are three sub categories of such cables based on different installation timelines:

1. non-tree retardant (Non-TR), direct buried (before 1989)
2. tree retardant (TR), direct buried (1989 to 1993)
3. tree retardant (TR), in-duct (after 1993).

For non-TR and TR direct buried cables, assuming that at the ages of 20 and 40 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve. For TR in-duct cables, the ages of 40 and 55 were used.

The following curves show the survival curves for each cable type. Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figures.

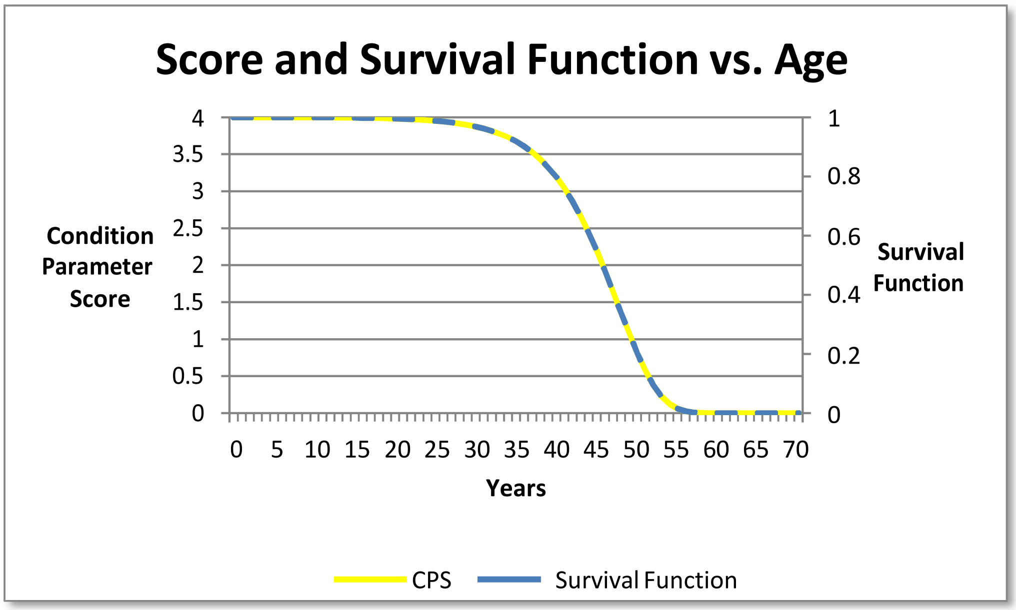


Figure 8-1 Underground Primary Cables Age Criteria – Non-TR and TR Direct Buried XLPE

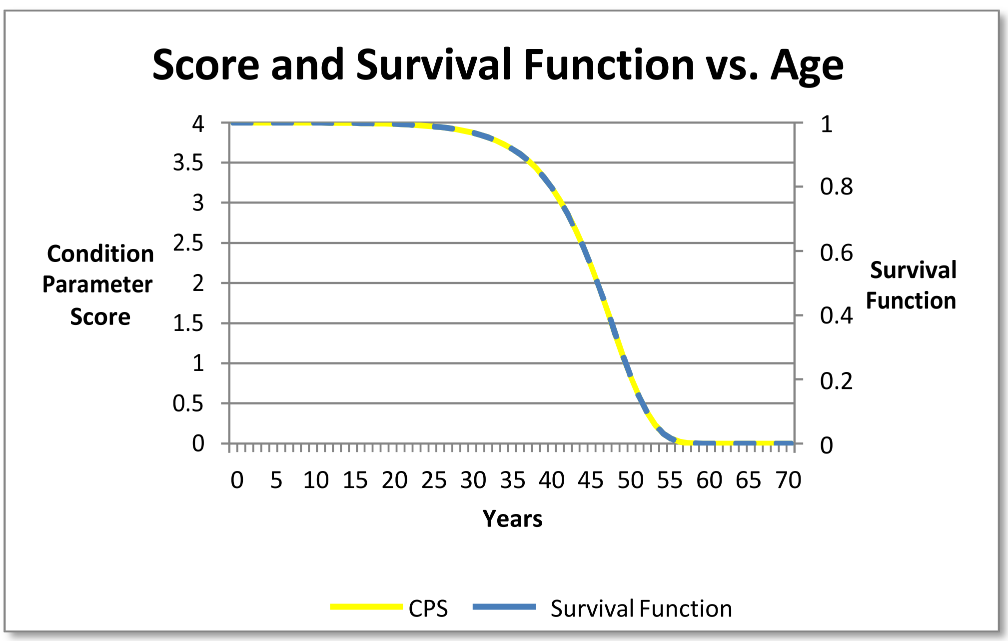


Figure 8-2 Underground Primary Cables Age Criteria – TR Direct Buried XLPE

De-Rating (DR)

A de-rating multiplier will be applied to units based on the number of cable in the last 5 years.

Table 8-2 De-Rating Criteria

Number of Failures in last 5 years	De-Rating Multiplier (DR)
0	1
1	0.9
2	0.7
3	0.5
> 3	0.25

8.2 Age Distribution

Main Feeder Cables

The average age was 18 years. Approximately 4% were 40 years or older. The age distribution for this asset class was as follows:

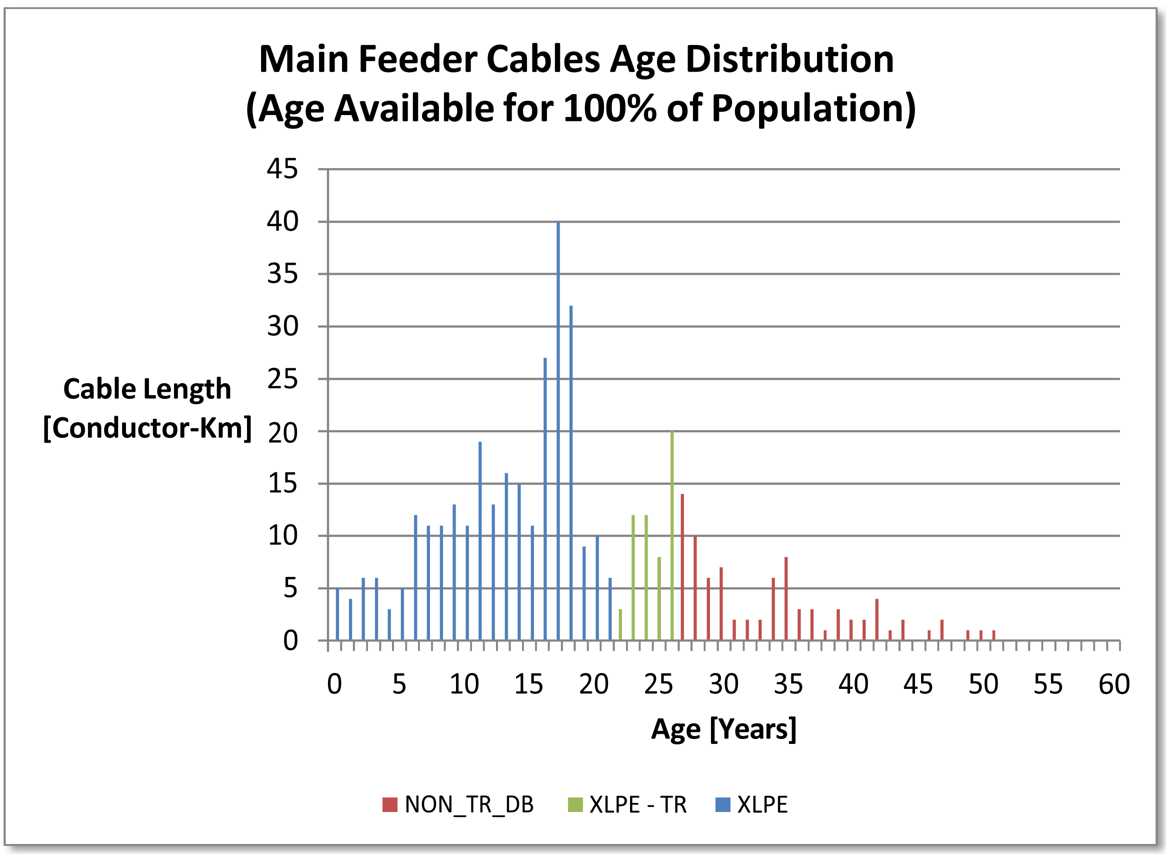


Figure 8-3 Main Feeder Cables Age Distribution

Distribution Cables

The average age was 21 years. Approximately 7% were 40 years or older. The age distribution for this asset class was as follows:

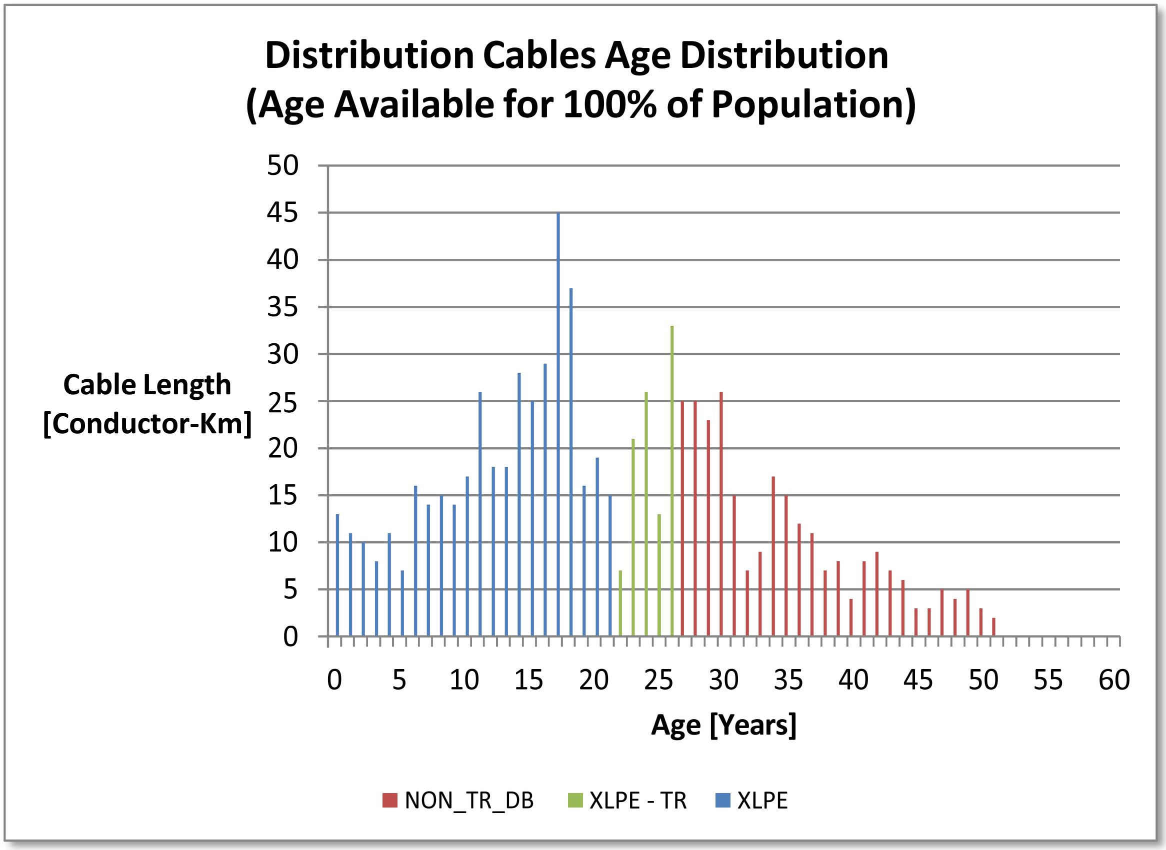


Figure 8-4 Distribution Cables Age Distribution

8.3 Health Index Results

Main Feeder

A total of 2238 conductor-km of Main Feeder Cables had sufficient data for a Health Indexing.

The average Health Index for this asset group was 75%. Approximately 12% of population was in "poor" or "very poor" condition.

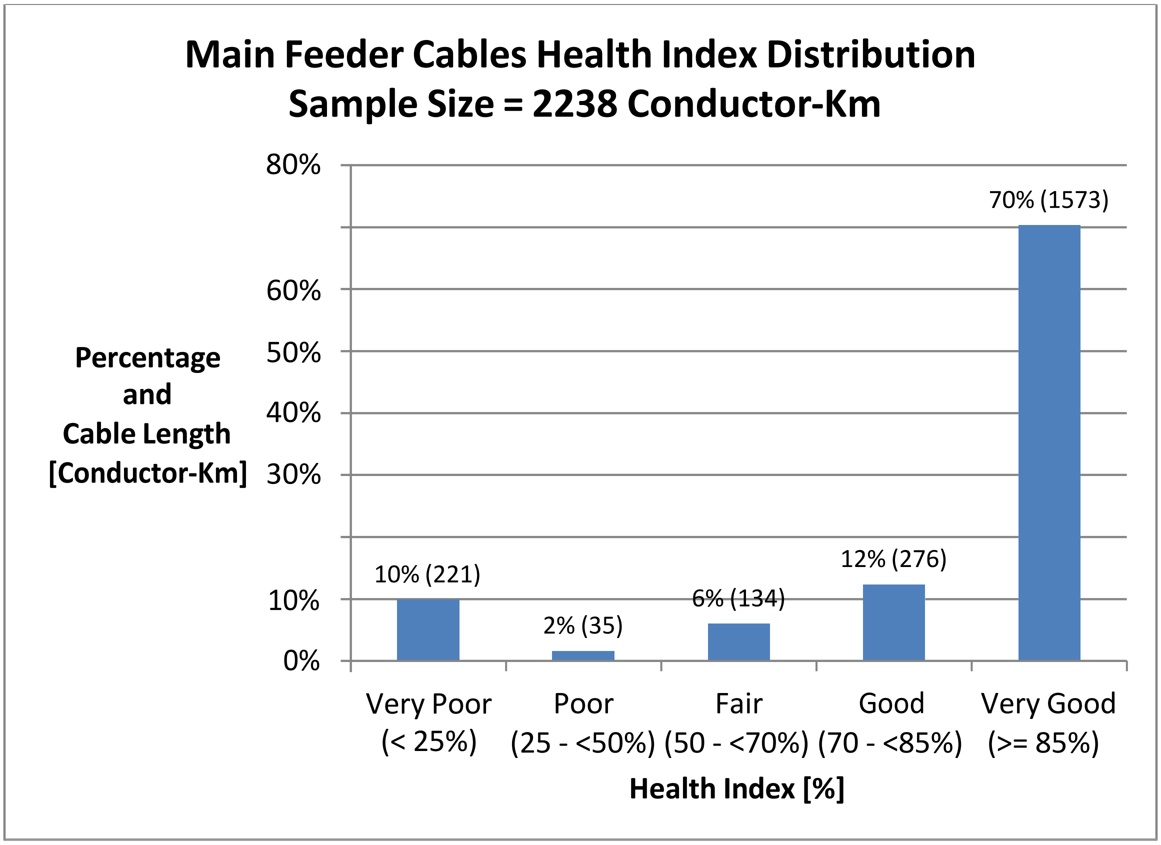


Figure 8-5 Main Feeder Cables Health Index Distribution

Distribution Cables

A total of 4076 conductor-km of Main Feeder Cables had sufficient data for a Health Indexing.

The average Health Index for this asset group was 75%. Approximately 21% of population was in “poor” or “very poor” condition.

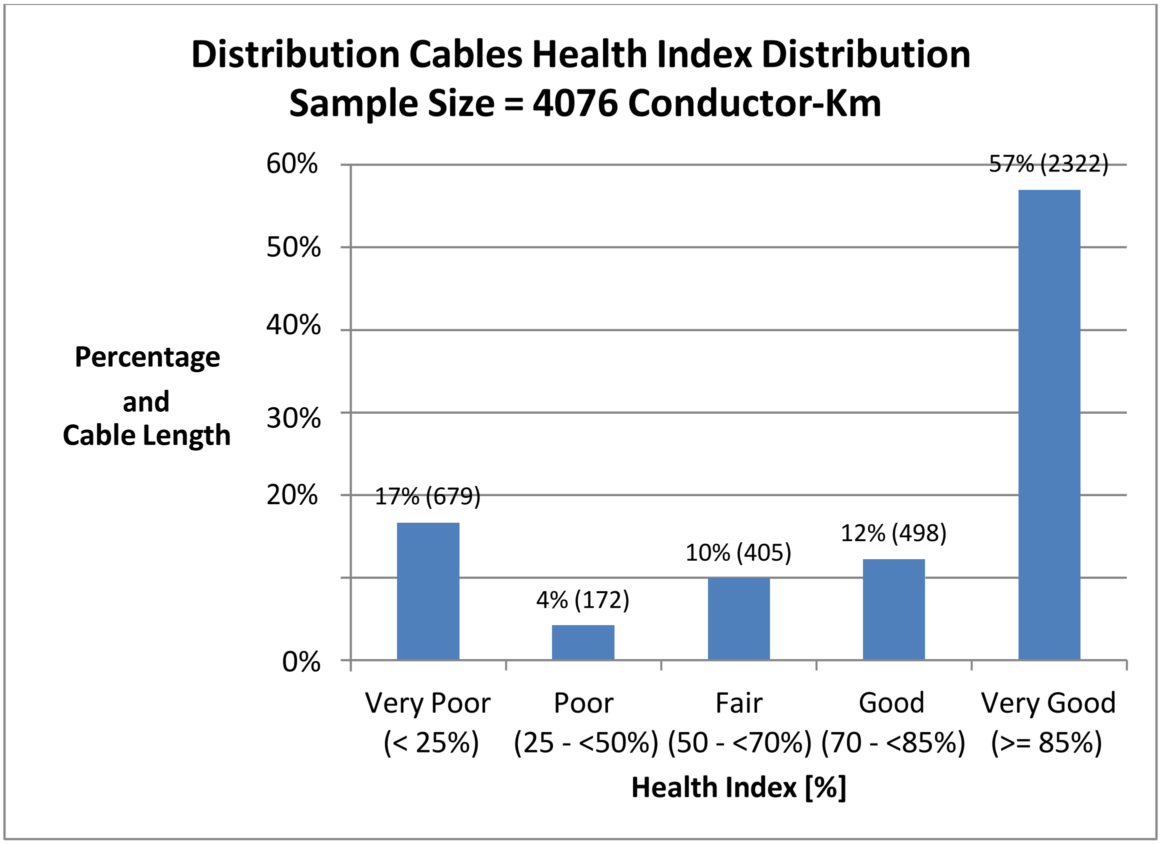


Figure 8-6 Distribution Cables Health Index Distribution

8.4 Flagged for Action Plan

As it is assumed that Underground Primary Cables were reactively replaced, the flagged for action plan was based on the asset failure rate.

Main Feeder Cables

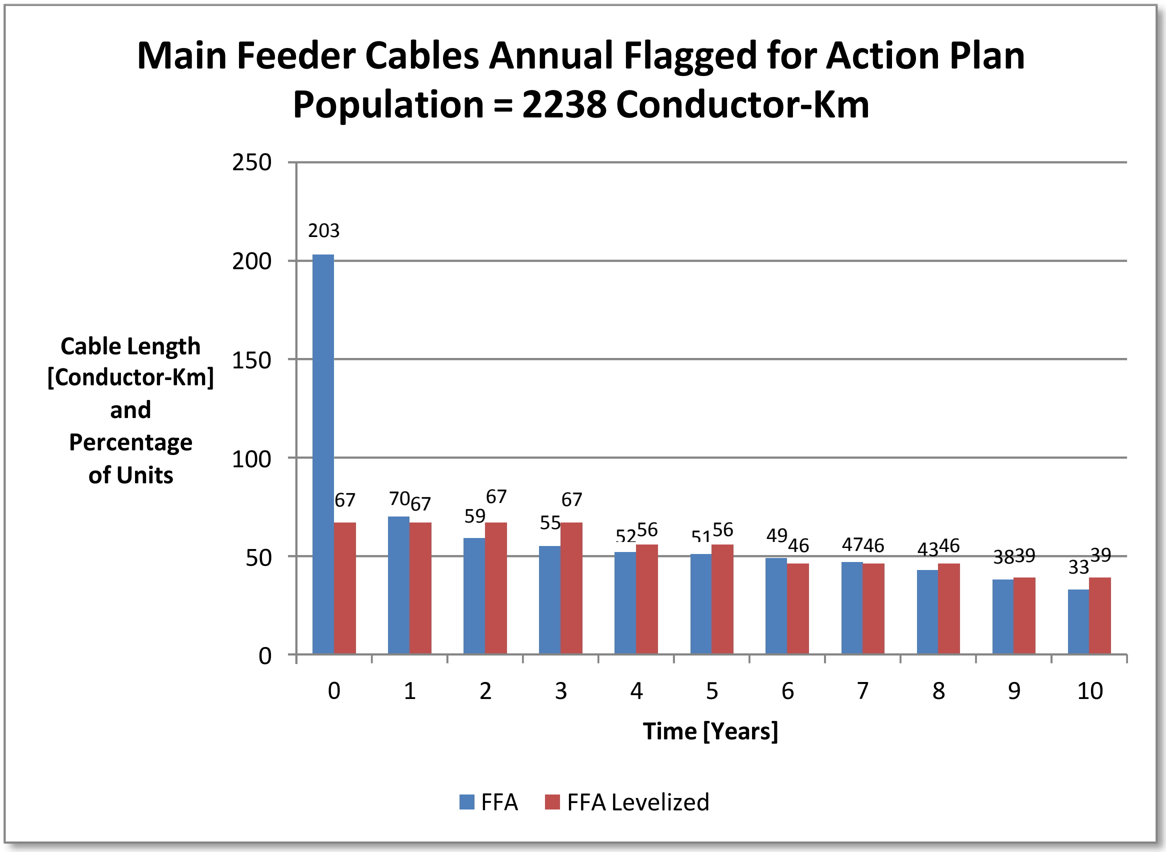


Figure 8-7 Main Feeder Cables Flagged for Action Plan

Distribution Cables

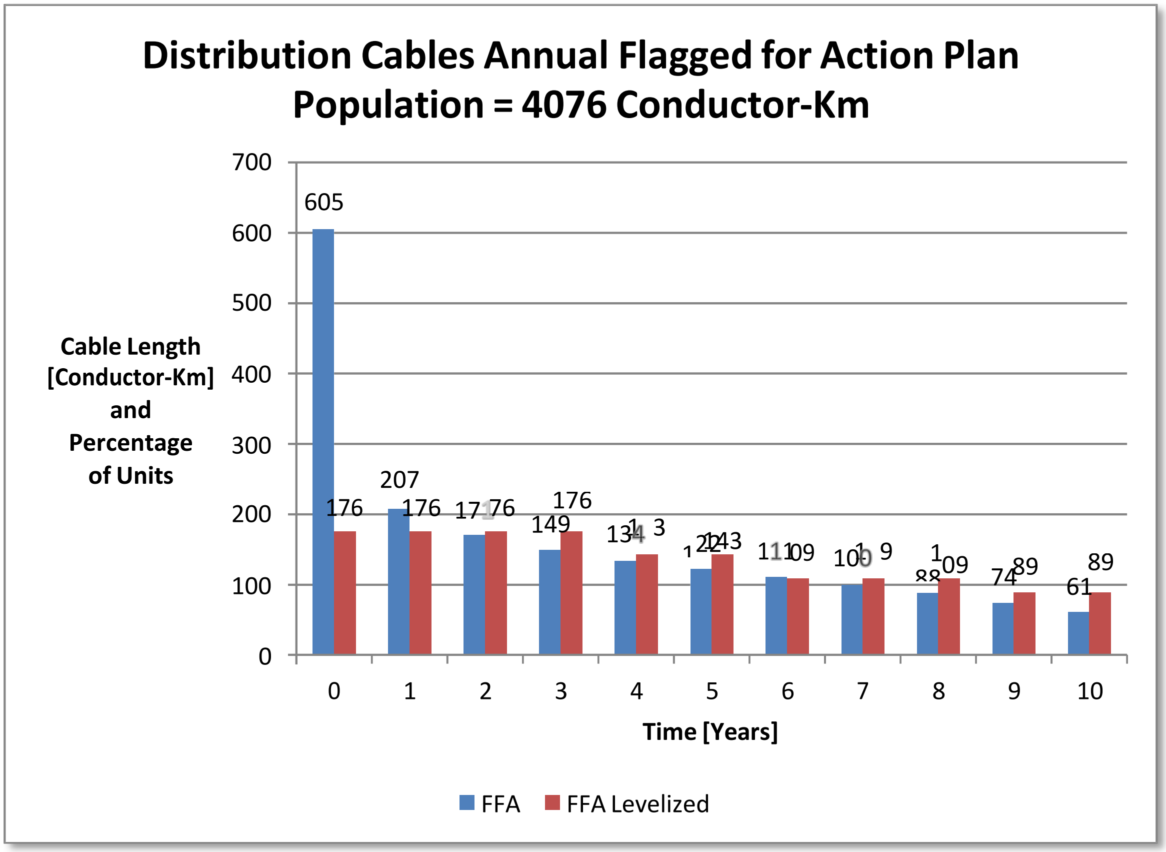


Figure 8-8 Distribution Cables Flagged for Action Plan

8.5 Data Analysis

Age data was available for Underground Cables and because age was known for all segments, the average DAI for both Main Feeder and Distribution Cables sub-categories was 100%. This, however, does not mean that there is a high degree of confidence in the HI results as there is a general lack of data with cables.

Enersource should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta). Such information will provide good, objective condition data as input into the Health Index. Other data gaps include.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splice & Termination	Physical Condition	++	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		++	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record
Cable Tests	Physical Condition	+++	Cable Overall Condition	Gross/major defects; weak spots/bulk degradation in insulation; water treeing; localized defects in cable and accessories	Tests: insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta

9 POLES

This asset category includes wood and concrete poles.

9.1 Health Index Formula

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Wood Pole Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Pole Strength	**5**	**1**	1	Pole Strength	1	**1**	Table 9-3
2	Physical Condition	**4**	**1**	1	Shell Rot	**2**	**1**	Table 9-4
				2	Mechanical Damage	**1**	**1**	Table 9-4
				3	Crack	**2**	**1**	Table 9-4
				4	Pole Top Feathering	**2**	**1**	Table 9-4
				5	Lean	**1**	**1**	Table 9-4
3	Pole Accessories	**1**	**1**	1	Cross-arm	**5**	**1**	Table 9-4
				2	Ground Wire	**2**	**1**	Table 9-4
				3	Guy	**1**	**1**	Table 9-4
4	Service Record	**3**	**1**	1	Overall	**4**	**1**	Table 9-4
				2	Age	**1**	**1**	Figure 9-1
HI Maximum Limit				Overall Condition will limit maximum HI value				

Table 9-2 Concrete Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	**4**	**1**	1	Concrete Condition	**2**	**1**	Table 9-4
				2	Mechanical Damage	**1**	**1**	Table 9-4
				3	Crack	**2**	**1**	Table 9-4
				4	Lean	**1**	**1**	Table 9-4
2	Pole Accessories	**1**	**1**	1	Cross-arm	**5**	**1**	Table 9-4
				2	Ground Wire	**2**	**1**	Table 9-4
				3	Guy	**1**	**1**	Table 9-4
3	Service Record	**3**	**1**	1	Overall	**4**	**1**	Table 9-4
				2	Age	**1**	**1**	Figure 9-2
HI Maximum Limit				Overall Condition will limit maximum HI value				

9.1.2 Condition Criteria

<u>Pole Test</u>

Table 9-3 Pole Test Criteria

Score	**Condition Description (Resistograph Tests)**
4	Pass
2	Fail
0	Marginal

<u>Visual Inspections</u>

Table 9-4 Visual Inspection Criteria

Score	**Condition Description**			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

<u>Age</u>

Assume that the failure rate Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\{3(t\text{-}a)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f\text{-}e^{-a\{3})/\{3}}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 45 and 65 years the probability of failures (P_f) for Wood Poles are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

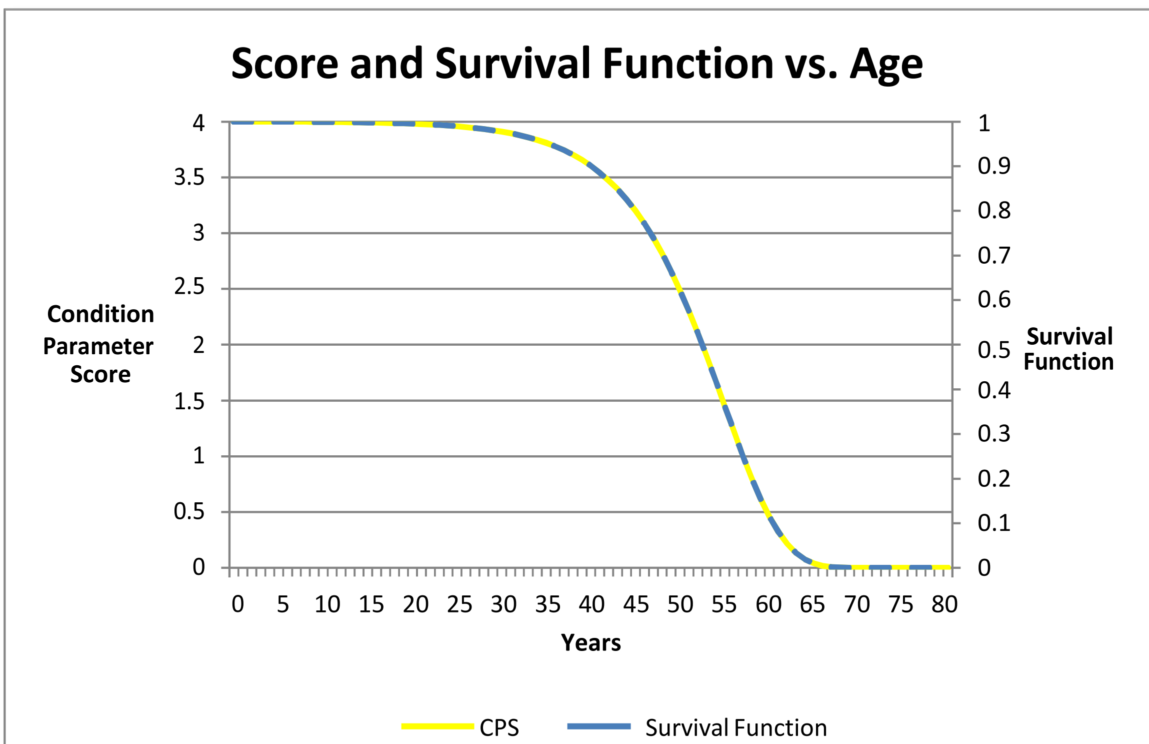


Figure 9-1 Wood Pole Age Criteria

For Concrete Poles, the ages at 20% and 99% probabilities of failure are 55 and 80 years, respectively.

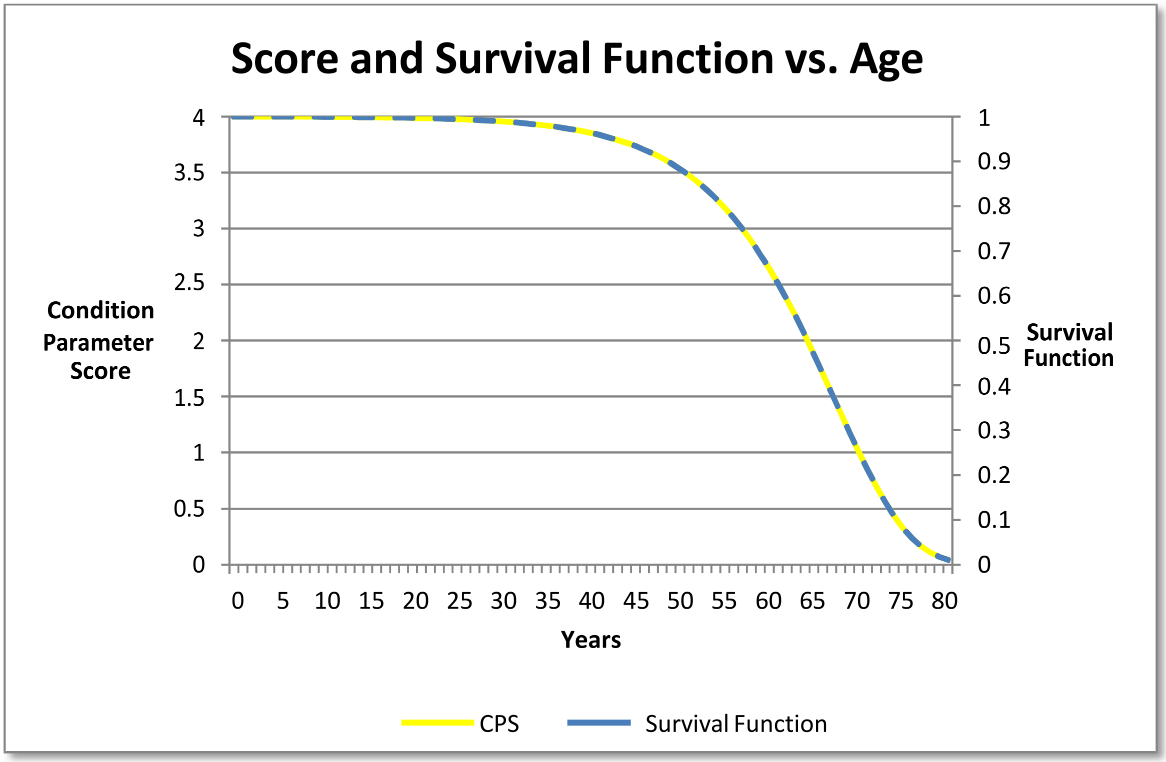


Figure 9-2 Concrete Pole Age Criteria

9.2 Age Distribution

The age distribution for this asset class was as follows:

Wood Poles

The average age for wood poles was 27. Approximately 18% of the population was 45 years or older.

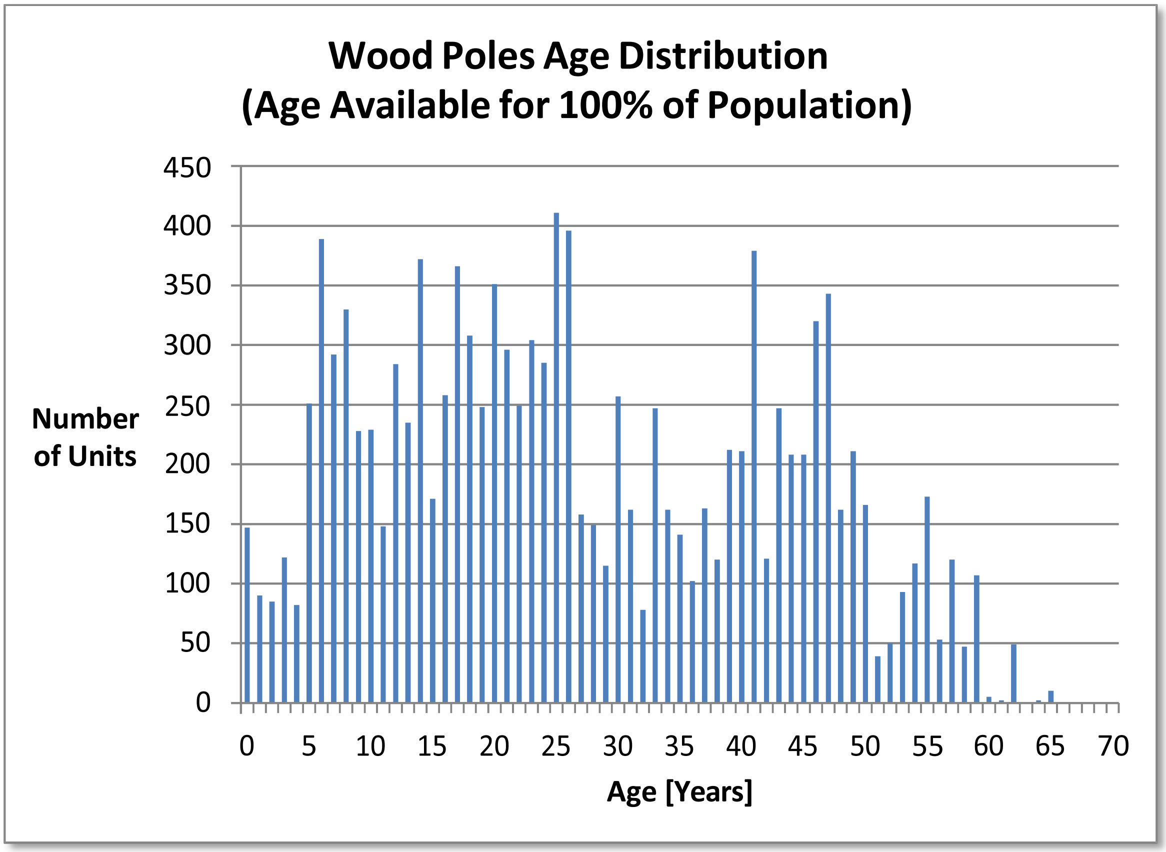


Figure 9-3 Wood Poles Age Distribution

Concrete Poles

The average age for concrete poles was 20 years. About 4% of all poles were 55 years or older.

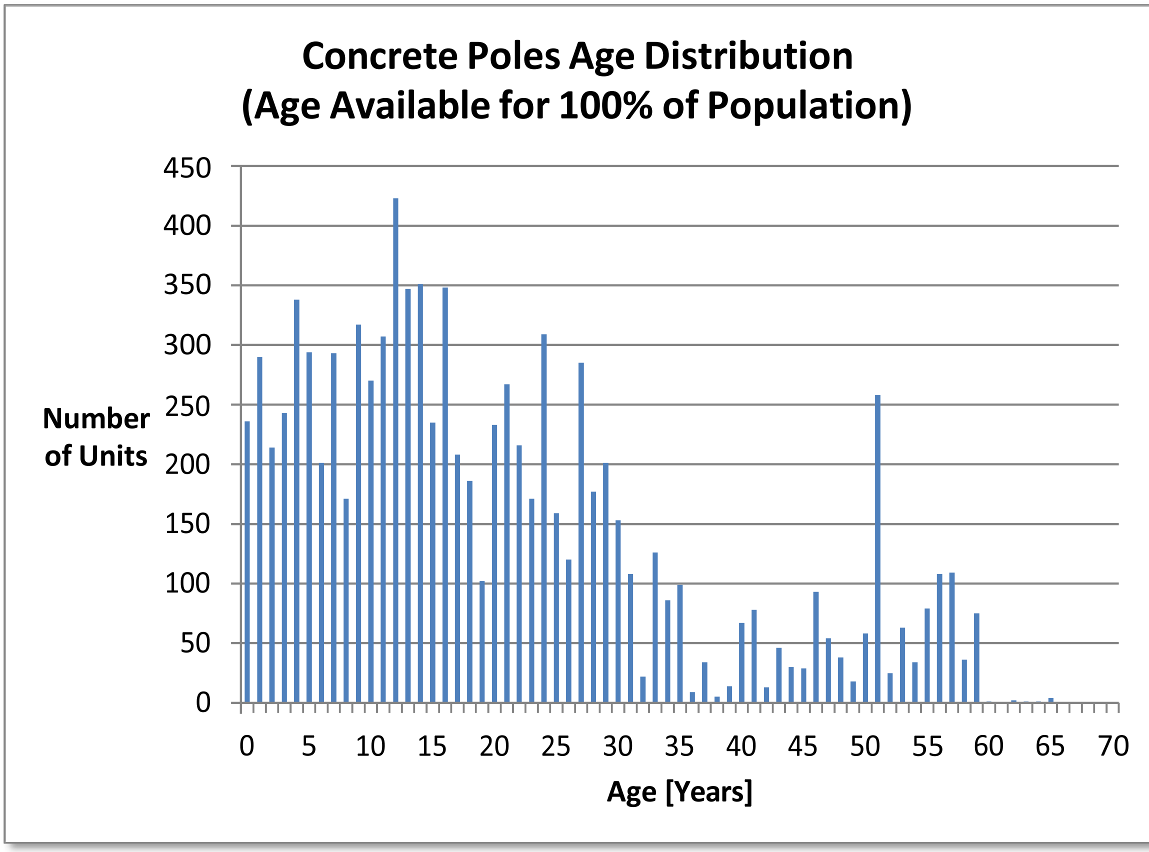


Figure 9-4 Concrete Poles Age Distribution

9.3 Health Index Results

Wood Poles

There are 12436 Wood Poles at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 73%. Approximately 15% of the samples were in "poor" or "very poor" condition.

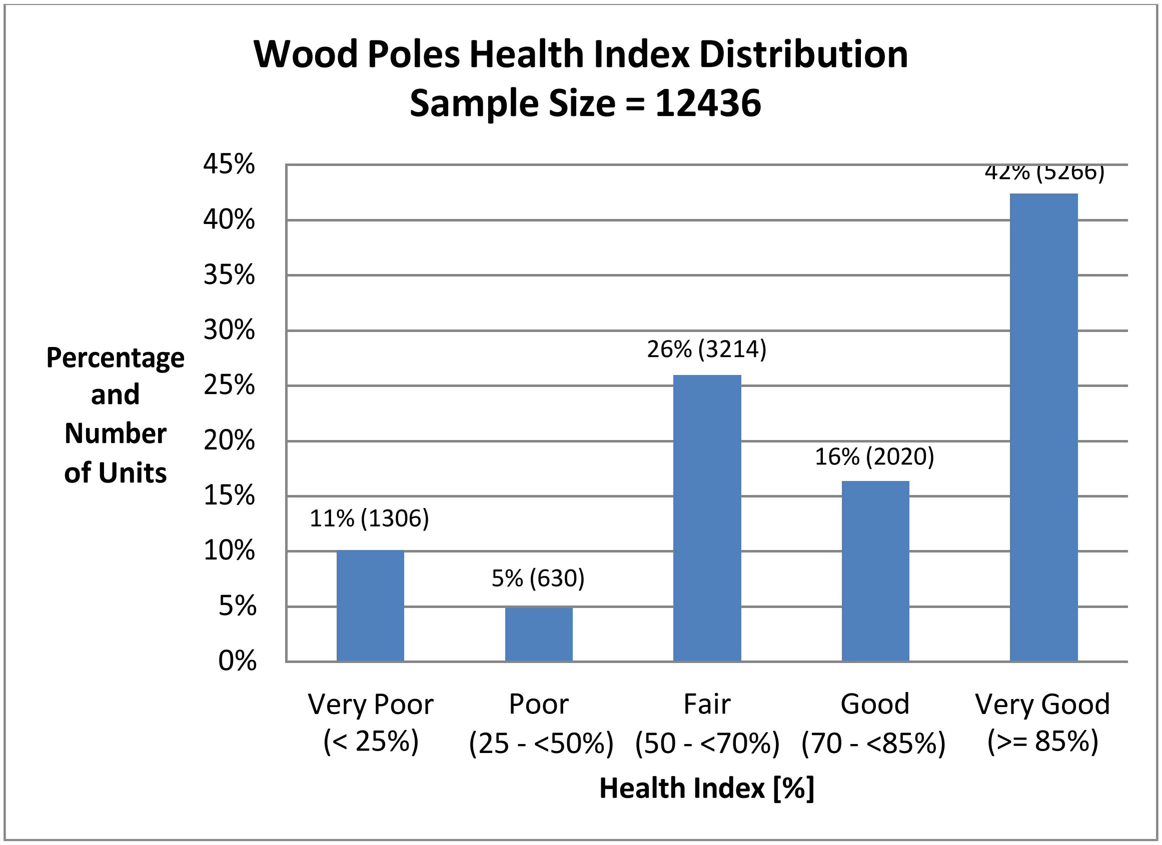


Figure 9-5 Wood Poles Health Index Distribution

Concrete Poles

There are 9488 Concrete Poles at Enersource. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was nearly 91%. Approximately 3% of the samples were in “poor” or “very poor” condition.

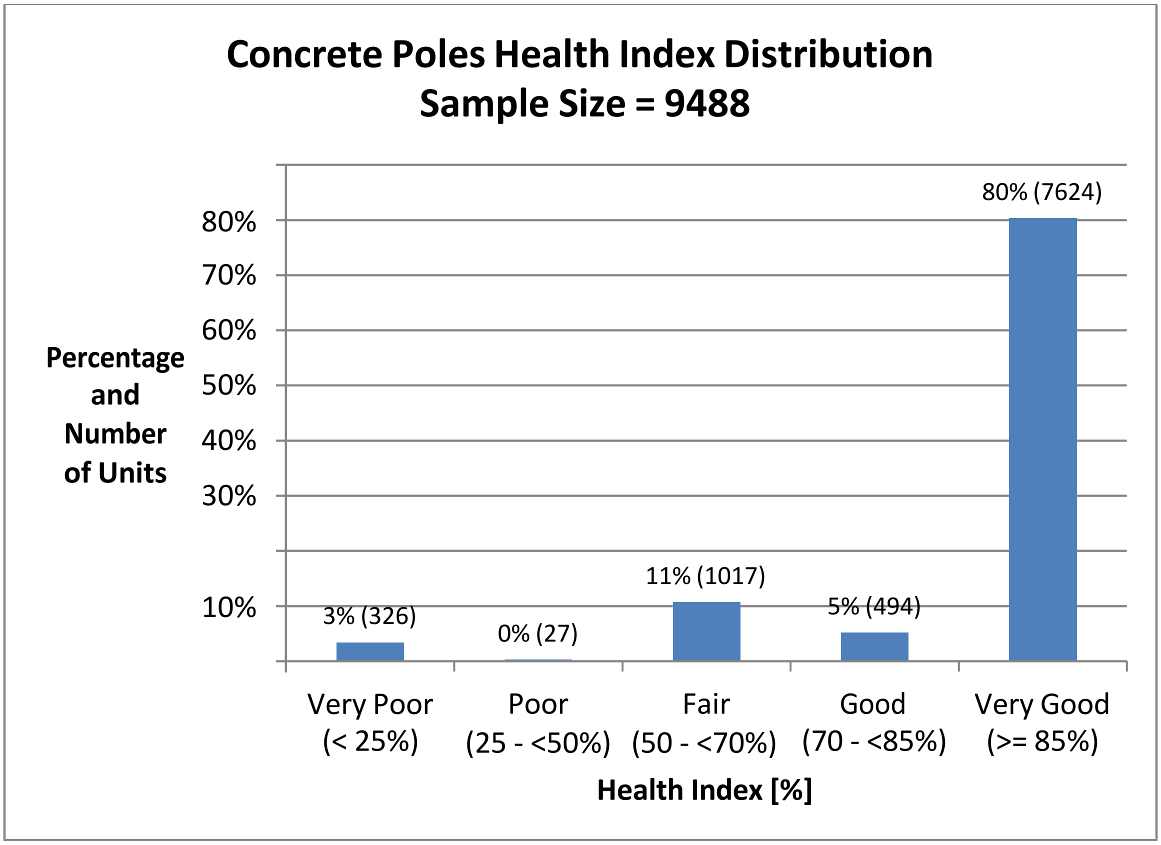


Figure 9-6 Concrete Poles Health Index Distribution

9.4 Flagged for Action Plan

Although these assets are proactively addressed, the flagged for action plan is estimated based on the failure rate.

Wood Poles

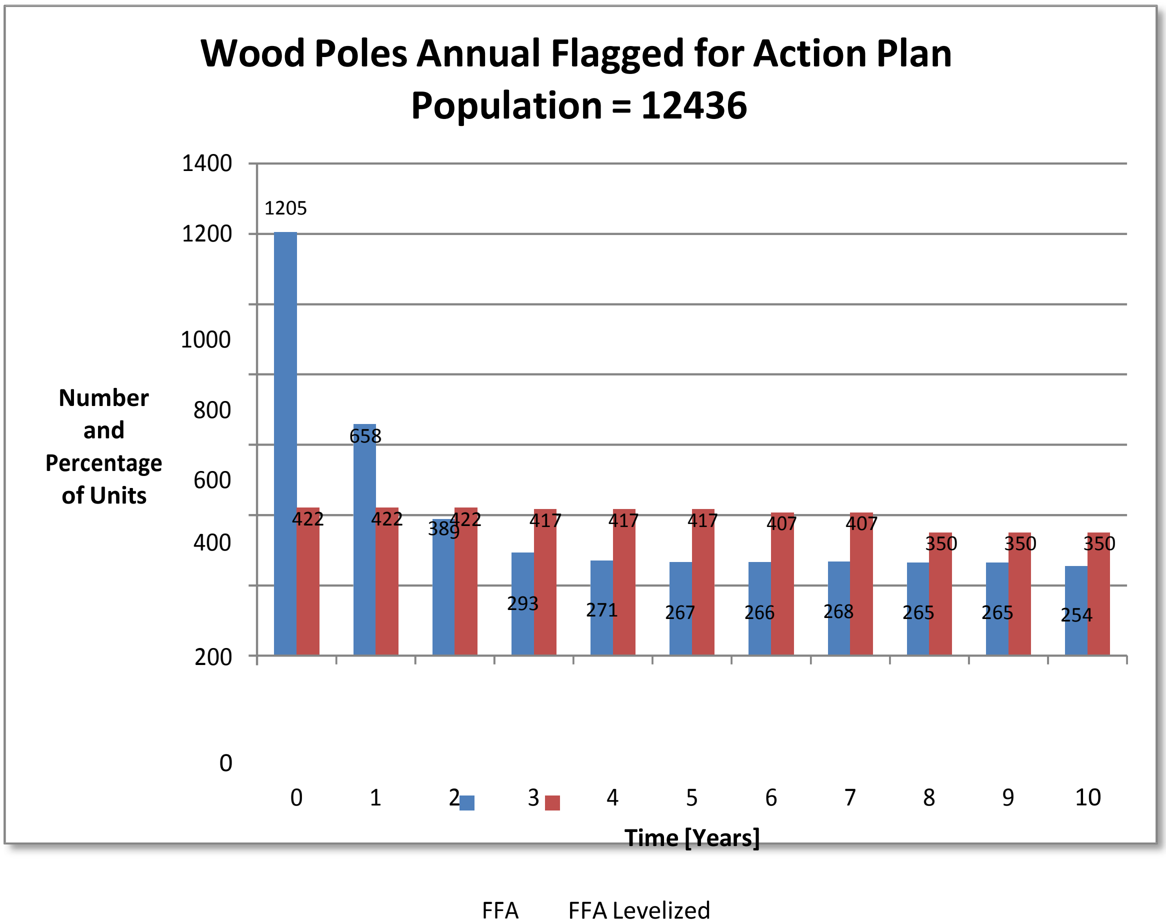


Figure 9-7 Wood Poles Flagged for Action Plan

Concrete Poles

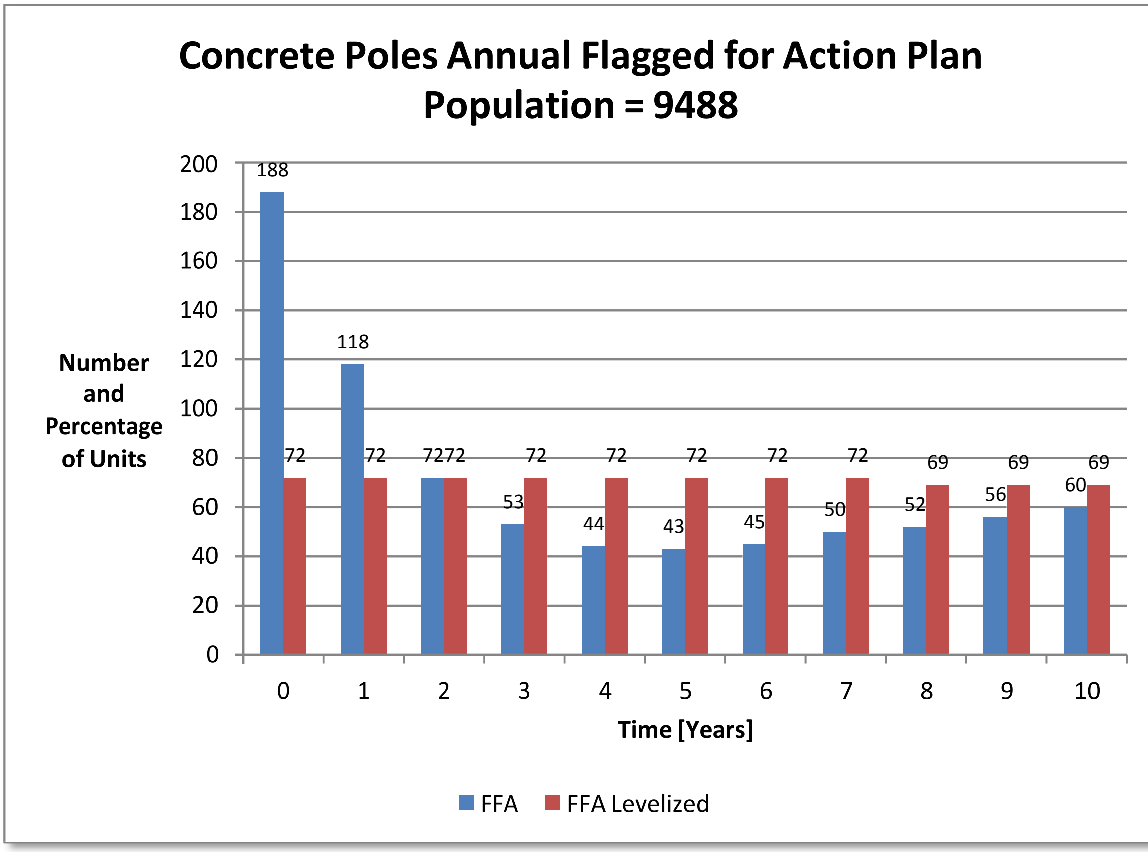


Figure 9-8 Concrete Poles Flagged for Action Plan

9.5 Data Analysis

The apparent decrease in DAI of wood poles is not a result of decreased data, but rather from a change in the health index formula. In 2015, Enersource made significant strides by conducting pole testing. The resulting resistograph test results were included in the formula. Since this parameter has a high weight and only 9% of the population was tested, the average DAI for this asset group is only 47% as compared to 55% from 2014. This is no cause for concern as this DAI will increase as more poles are tested. It should further be noted that over 90% of poles have been inspected. This is a vast improvement over the 40% that were inspected in 2014.

Concrete poles showed a significant increase in DAI (88% in 2015 vs. 55% in 2014). This is because of the significant increase in inspection data.

There are no data gaps for poles.

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Reference(s): Ex. 2/4/11, p. 22

Please explain why capital expenditures for rolling stock and grounds and buildings are higher after the merger. Please provide details of capital savings expected in these categories over 2018-2022 as a result of the merger.

Response:

The increase in capital expenditures for grounds and buildings are due to the replacement of equipment and building infrastructure that have surpassed end of life, are not meeting current operational requirements, or not meeting current building standards. As building and equipment conditions deteriorate they can create safety concerns as well as increase repair and maintenance efforts and costs. Some planned equipment and building infrastructure initiatives were deferred in the past due to financial or other resource constraints. However, many of the grounds and buildings projects can no longer be deferred and have reached the point where replacement is critical to operations and the safety of employees and the public. The increase in capital expenditures for rolling stock is due to the deferral of purchases for many larger vehicles, which were put on hold due to pending merger or financial constraints. Please see Alectra Utilities response to PRZ-Staff-8 for a forecast of transitional costs and merger savings.