EB-2015-0073

Guelph Hydro Electric Systems Inc. ("Guelph Hydro")

Technical Conference Undertaking Responses

August 21, 2015

GUELPH HYDRO ELECTRIC SYSTEMS INC.

EB-2015-0073
Technical Conference
August 10, 2015

Undertakings

Undertakings J	Description	Date Filed
Volume 1, August 10, 2015		
JT1.1	**IN RESPECT OF THE APPENDIX ATTACHED TO 1-SEC-9, TO PROVIDE A RECONCILIATION WITH A CONTINUITY SCHEDULE OF CAPITAL EXPENDITURE, OM&A EXPENDITURES, AND OTHER REVENUE**	August 21, 2015
JT1.2	**TO PROVIDE INFORMATION REGARDING HOW THE CONCLUSIONS IN THE SURVEYS WERE DERIVED**	August 21, 2015
JT1.3	**TO ASK UTILITYPULSE TO PROVIDE THE LIST OF THE LDCS TO WHOM GUELPH HYDRO IS COMPARED IN THE SURVEY AS A CONFIDENTIAL FILING**	August 21, 2015
JT1.4	**TO CONFIRM WHETHER THE APPLICANT RESTATED GROSS CAPITAL COST DOWN TO NET BOOK VALUE AT THE TIME IT CONVERTED TO IFRS**	August 21, 2015
JT1.5	**TO PROVIDE WHAT THE GROSS FIXED ASSETS WOULD BE WITHOUT THE ADJUSTMENT AT THE TIME OF IFRS**	August 21, 2015
JT1.6	**TO PROVIDE THE LIST OF ACTIONS REFERENCED IN 1-SEC-5**	August 21, 2015
JT1.7	**TO RECALCULATE THE FIGURES PROVIDED ON ROE WITH ADJUSTMENTS**	August 21, 2015
JT1.8	**TO PROVIDE THE DEVELOPMENT PLAN REFERENCED IN 1-SEC-16, WHEN COMPLETED**	August 21, 2015
JT1.8	**(REVISED) TO PROVIDE THE STRATEGIC PLAN, WHEN AVAILABLE**	August 21, 2015

Undertakings J	Description	Date Filed
JT1.9	**TO PROVIDE A CALCULATION OF THE CHANGE IN OM&A EXPENSES FROM 2015 TO 2016 THAT SEPARATES THE LABOR COMPONENT OF OM&A FROM THE NON LABOUR COMPONENT, NETS OUT ESTIMATED GROWTH AND PRODUCTIVITY, AND APPLIES A MEASURE OF INFLATION TO THESE NET OM&A AMOUNTS TO DETERMINE WHAT THE INCREASE IN OM&A WOULD HAVE BEEN UNDER THIS ANALYSIS**	August 21, 2015
JT1.10	**TO PROVIDE THE SOURCE OF THE CALCULATION OF THE NEGATIVE 5 PER CENT EFFICIENCY RATING REFERENCED IN THE RESPONSE TO 1-SEC-1 AT PAGE 37**	August 21, 2015
JT1.11	**TO RECONCILE THE RESPONSE IN THE INTERROGATORY, THE $206,349 OF THE ALLOCATED DEPRECIATION IS OM&A, AS COMPARED TO ALL OF THE ALLOCATED DEPRECIATION BEING SHOWN AS OM&A IN TABLE 1-4 IN THE ORIGINAL EVIDENCE, WHICH IS A FIGURE OF $550,440**	August 21, 2015
JT1.12	**TO CORRECT THE GLOBAL ADJUSTMENT AMOUNT ON TABLE 2-ENERGY PROBE-17-2**	August 21, 2015
JT1.13	**TO RECONCILE THE AMOUNTS AT TABLE 2-ENERGY PROBE-18 (A) AND (B), WITH THE CONTINUITY SCHEDULE**	August 21, 2015
JT1.14	**TO PROVIDE COMPARISONS OF CAPITAL ADDITIONS, BUDGETED AND ACTUAL FOR EACH OF THE STATED YEARS**	August 21, 2015
JT1.15	**TO COMPARE THE SYSTEM OPERATIONS AND MAINTENANCE COST REFERENCED IN 2-SEC-23 AND EXHIBIT 2, TAB 2, SCHEDULE 4, PAGE 2**	August 21, 2015
JT1.16	**TO PROVIDE THE HISTORICAL REACTIVE CAPITAL BUDGET FOR THE YEARS 2011 TO 2015 AND THE FORECASTS FOR 2016 TO 2020**	August 21, 2015
JT1.17	**TO PROVIDE THE 2011 AND 2013 ASSET CONDITION ASSESSMENT DOCUMENT**	August 21, 2015

Undertakings J	Description	Date Filed
JT1.18	**TO CONFIRM WHETHER OR NOT A CALCULATION BY REPLACEMENT FREQUENCY FOR A REPLACEMENT RATE BY ASSET TYPE CAN BE DONE**	August 21, 2015
JT1.19	**TO PROVIDE THE ACTUAL EXCEL SPREADSHEETS REFERENCED IN 2-SEC-51, 52, 55, AND 56**	August 21, 2015
JT1.20	**TO PROVIDE THE FINAL BUDGETED AMOUNTS FOR THE 2012 RATE APPLICATION**	August 21, 2015
JT1.21	**TO DETERMINE HOW THE ALPHA AND BETA WERE CHOSEN AND TO PROVIDE STATISTICAL EVIDENCE TO SUPPORT THE USEFUL LIFE, STATISTICAL EVIDENCE TO SUPPORT THE SELECTION OF THE USEFUL LIFE, AND IN ADDITION, TO EXPLAIN WHETHER THE CURVE HERE AND THE DISCUSSION REFERS TO AN EXAMPLE OR WHETHER IT REFERS TO CAN ACTUAL SITUATION IN GUELPH HYDRO**	August 21, 2015
JT1.22	**TO PROVIDE THE PORTION OF COSTS BORNE BY THE CITY IN 2012 FOR EACH OF THE YEARS**	August 21, 2015
JT1.23	**WITH REFERENCE TO 4-ENERGY PROBE-32(E), TO PROVIDE AN UPDATED TABLE 4-5**	August 21, 2015
JT1.24	**WITH REFERENCE TO TABLE 4-ENERGY PROBE-41(A), TO PROVIDE 2012 TO 2015 ACTUALS**	August 21, 2015
JT1.25	**WITH REFERENCE TO 4-ENERGY PROBE-42, TO QUANTIFY THE INCREASE IN REVENUE GENERATED FROM WATER BILLING SERVICES**	August 21, 2015
JT1.26	**TO CONFIRM THAT THE CHANGE IN 4-ENERGY PROBE-50(c) IS INCLUDED IN LINE 5**	August 21, 2015
JT1.27	**TO CLARIFY WHAT WAS MEANT BY THE WORDS “TIME CONTRAINTS” IN THE INTERROGATORY RESPONSE**	August 21, 2015
JT1.28	**TO GO THROUGH THE DEPARTMENTAL BUDGETS AND EXPAND ON WHATEVER CAN BE FOUND**	August 21, 2015

Undertakings J	Description	Date Filed
JT1.29	**TO CALCULATE THE OM&A PER CUSTOMER, MAY 2014 AND MAY 2015, AND TO INCLUDE WHETHER THAT OM&A PER CUSTOMER FIGURE IS SIGNIFICANTLY LESS THAN THE 6.45 PER CENT THAT IS SEEN IN 4-ENERGY PROBE-38, AND TO GIVE AN EXPLANATION AS TO WHY IT'S SO MUCH LOWER FOR THE FIVE-MONTH PERIOD THAN FOR THE FORECAST 12-MONTH PERIOD**	August 21, 2015
JT1.30	**TO ADVISE WHETHER THE 14 ASSUMED RETIREMENTS CAN GO IN TABLE 4**	August 21, 2015
JT1.31	**TO CONFIRM THE 167,870 FIGURE FOR 2015 BUDGET INCREASE, AS STATED IN 4-STAFF-50, UNDER (A)**	August 21, 2015
JT1.32	**TO PROVIDE THE BREAKDOWN IN 4-VECC-38C FOR 2012 TO 2015**	August 21, 2015
JT1.33	**TO DESCRIBE THE COSTS IF INCREMENTAL SERVICES**	August 21, 2015
JT1.34	**BASED IN ANY FURTHER UPDATES OR CORRECTIONS OR OTHER CHANGES MADE AS A RESULT OF THE TECHNICAL CONFERENCE QUESTIONS, TO PROVIDE AN UPDATE TO THE RESPONSE TO THIS QUESTION, INCLUDING AN UPDATED REVENUE REQUIREMENT WORK FORM IN ELECTRONIC FORM**	August 21, 2015
JT1.35	**IF NECESSARY, TO PROVIDE AN UPDATE TO TABLE 7-ENERGY PROBE-58(B) TO REFLECT ANY CHANGES IN THE REVENUE DEFICIENCY AS A RESULT OF THE UPDATES, CORRECTIONS, OR CHANGES TO THE APPLICATION AS A RESULT OF THE RESPONSES TO THE TECHNICAL CONFERENCE QUESTIONS**	August 21, 2015
JT1.36	**Number skipped. Being used to file Board Staff's July 6, 2015 presentation - Rate Design – Commercial / Industrial Stakeholder Consultation**	August 21, 2015

Undertakings J	Description	Date Filed
JT1.37	**TO PROVIDE WHATEVER BUSINESS CASE CAN BE PROVIDED WITH RESPECT TO THE ZIGBEE CHIP**	August 21, 2015

Table of Contents

Guelph Hydro Technical Conference Undertaking Responses

UNDERTAKING NO. JT1.1

IN RESPECT OF THE APPENDIX ATTACHED TO 1-SEC-9, TO PROVIDE A RECONCILIATION WITH A CONTINUITY SCHEDULE OF CAPITAL EXPENDITURE, OM&A EXPENDITURES, AND OTHER REVENUE.

Response:

The slides attached as Appendix 1-SEC-9 were presented to the GHESI Board of Directors on November 26, 2014. As is frequently the case, the budget documents are not static and new decisions on needed capital and OM&A expenditures occurred prior to the filing of the Application on April 24, 2015. The Application best reflects the needs of GHESI in the test year.

The first part of this response provides a reconciliation between capital expenditures re Appendix attached to 1-SEC-9 (Slide deck presented to the Board of Directors), and the Continuity Schedules capital additions in Exhibit 2 (Table 2-8: 2015 and Table 2-9: 2016).

As part of this reconciliation Guelph Hydro also provided how the capital expenditures in the appendix that was attached to 1-SEC-9 reconciles with the capital expenditures in 2-Energy Probe-18 a) which in turn reconciles with the capital additions outlined in 2-Energy Probe-18 b).

1 **Table JT1.1-1: 2015 Capital Expenditures and Continuity Schedule Reconciliation**

Capital Expenditure Reconciliation between Appendix attached to 1-SEC-9 and Capital Additions in Continuity Schedules (Table 2-8 (2015) and 2-9(2016))		
Fiscal Year:	2015	
Capital Expenditures as noted on Distribution Capital Summary (page 15) in the Appendix attached to 1-SEC-9 (Net of Contributed Capital)		12,021
Addback: Contributed Capital		3,057
Less: Forecasted AFUDC on the projected closing CWIP		(41)
Gross Capital Expenditures before Contributed Capital as per Distribution Capital Summary (page 15) in the Appendix attached to 1-SEC-9		15,037
Additional Capital Expenditures included in Cost of Service Filing post Board Approval		
	Building Expansion	500
	Computer Hardware / Software upgrade re: Metering Dept	325
Revised Capital Expenditures included in Cost of Service Filing before Contributed Capital as per Exhibit 2 (Table 2-21) and 2 Energy Probe 18 a)		15,862
Addback: Opening CWIP Distribution System		4,552
Addback: Opening CWIP General Plant		606
Less: Closing CWIP Distribution System		(1,200)
Less: Closing CWIP General Plant		0
Gross Capital Additions Rolled into Rate base prior to Contributed Capital as per 2 Energy Probe 18 b)		19,820
Less: Contributed Capital		(3,057)
Net Capital Additions Rolled into Rate base as per the Continuity Schedule (Table 2-8) (Before Closing CWIP which is not part of Rate Base)		16,763

2

Table JT1.1-2: 2016 Capital Expenditures and Continuity Schedule Reconciliation

Fiscal Year: 2016	
Capital Expenditures as noted on Distribution Capital Summary (page 15)	
in the Appendix attached to 1-SEC-9 (Net of Contributed Capital)	10,073
Addback: Contributed Capital	3,148
Less: Forecasted AFUDC on the projected closing CWIP	(39)
Gross Capital Expenditures before Contributed Capital	13,182
as per Distribution Capital Summary (page 15) in the Appendix attached to 1-SEC-9	
Additional Capital Expenditures included in Cost of Service Filing post Board Approval	
Building Expansion	645
General Office Equip relating to the new Office expansion	103
Revised Capital Expenditures included in Cost of Service Filing before Contributed Capital	13,930
as per Exhibit 2 (Table 2-21) and 2 Energy Probe 18 a)	
Addback: Opening CWIP Distribution System	1,200
Addback: Opening CWIP General Plant	0
Less: Closing CWIP Distribution System	(1,200)
Less: Closing CWIP General Plant	0
Gross Capital Additions Rolled into Rate base prior to Contributed Capital	
as per 2 Energy Probe 18 b)	13,930
Less: Contributed Capital	(3,148)
Net Capital Additions Rolled into Rate base as per the Continuity Schedule (Table 2-8)	10,782
(Before Closing CWIP which is not part of Rate Base)	

The second part of this response reconciles OM&A Expenditures between the Budget taken to the Guelph Hydro Board of Directors for approval and the "Revenue Requirement" OM&A as filed in EB-2015-0073.

Table JT1.1-3: Reconciliation of 2014 OM&A Expenditures

2014 Actual OM&A	**$15,638,173**
Less:	
Water Billing Costs	487,887
Shared Services Expenses	667,418
Property Taxes	327,567
Utility Solution Costs	58,595
Add:	
Other	7,560
2014 Revenue Requirement OM&A	**$14,104,266**

Table JT1.1-4: Reconciliation of 2015 OM&A Expenditures

2015 Budget OM&A	**$ 16,213,428**
Less:	
Water Billing Costs	487,081
Shared Services Expenses	684,458
Property Taxes	330,126
Utility Solution Costs, SR&ED Credits	152,711
Add:	
Actuarial Adjustments	24,907
Shared Services Revenue	749,110
2015 Revenue Requirement OM&A	**$ 15,333,069**

Table JT1.1-5: Reconciliation of 2016 OM&A Expenditures

2016 Budget OM&A	**$**	**16,853,465**
Less:		
Water Billing Costs		506,446
Board Expenses		10,550
Shared Services Expenses		679,452
Property Taxes		335,074
Utility Solution Costs, SR&ED Credits		143,749
Add:		
Monthly Billing		360,000
Actuarial Adjustments		50,213
Regulatory Costs related to COS		63,300
Shared Services Revenue		743,904
Donations		9,000
Other		250
2016 Revenue Requirement OM&A	**$**	**16,404,861**

UNDERTAKING NO. JT1.2

TO PROVIDE INFORMATION REGARDING HOW THE CONCLUSIONS IN THE SURVEYS WERE DERIVED.

Response:

With regard to the following statements,

> *"The vast majority of customers are happy with the reliability of Guelph Hydro's systems ..."*

> *"…and customers are happy with outage restoration times."*

These statements were derived from:

Online Customer Survey Results – Exhibit 1, Appendix 1-D, page 14

- **83%** of survey respondents rated Guelph Hydro's performance in minimizing power outages as "Good" or "Excellent"
- **82%** of survey respondents said the time within which Guelph Hydro restores power when a power outage occurs is "Good" or "Excellent"
- **91%** of survey respondents said the overall reliability of the electricity service is "Good" or "Excellent"

Regarding the bullet point:

> "Respondents do not feel Guelph Hydro should be investing additional funds and raising rates to reduce the number of power outages and respondents do not want to see Guelph budget for long-term projects to move overhead services underground."

These statements were derived from:

Online Customer Survey – Exhibit 1, Appendix 1-D, page 15

- 81% did not want to see Guelph Hydro budget for a long-term project to move overhead services underground

UNDERTAKING NO. JT1.3

TO ASK UTILITYPULSE TO PROVIDE THE LIST OF THE LDCS TO WHOM GUELPH HYDRO IS COMPARED IN THE SURVEY AS A CONFIDENTIAL FILING.

Response:

Guelph Hydro contacted Sid Ridgley of UtilityPULSE / Simul Corporation and requested that he provide the LDC comparators and calculations for CEPr and CEI as a confidential filing.

Attached in Appendix JT1.3 is a letter containing his response.

Guelph Hydro affirms its response given in the technical conference that it does not have the list requested in this undertaking, and is thus unable to provide information it simply does not have.

> "MR. SHEPHERD: Do you have the list?
>
> MS. BIRCEANU: No, we don't.
>
> MR. SHEPHERD: Okay. Well, please undertake to find out whether they will provide it. We will file a motion if they don't say yes, so you can tell them that."

Guelph Hydro is concerned that any motion to compel Guelph Hydro to produce information which it has clearly stated on the record that it does not have would serve to lengthen unnecessarily the duration of this process.

Guelph Hydro also has serious concerns about the precedent that would be established if the Board should issue an order to compel a third party to produce sensitive commercial information, particularly when the disclosure of information in question could undermine that third party's entire business model, and particularly when that third party is not a party in this legal process.

Guelph Hydro is concerned that such an approach could lead to inappropriate discovery of a whole host of other third parties whose reports form part of the factual record in any Application. The logical outcome would be that many of those third parties, to avoid the risk of being compelled to disclose their sensitive commercial information, would simply refuse to allow LDCs to file those reports at all in the future. The result of that would be a record before the OEB that is substantially worse, not better, than it would have been otherwise.

UNDERTAKING NO. JT1.4

TO CONFIRM WHETHER THE APPLICANT RESTATED GROSS CAPITAL COST DOWN TO NET BOOK VALUE AT THE TIME IT CONVERTED TO IFRS.

Response:

Guelph Hydro confirms that it did restate its gross capital cost of its PP&E down to net book value when it converted to IFRS, effective January 1, 2010.

Guelph Hydro was one of the first utilities to adopt IFRS and the Board did not request or indicate that this was the wrong thing to do during its Cost of Service application presented in 2011 for 2012 rate rebasing.

However, subsequent to Guelph Hydro's transition, through Article 315 in the Accounting Procedures Handbook the Board is requesting that PP&E be reported using historical acquisition costs for regulatory purposes even though another method of measurement was elected (in Guelph Hydro's case - restated costs) for financial reporting purposes.

Guelph Hydro agrees to restate its PP&E for regulatory purposes in accordance with Article 315 of the Accounting Procedures Handbook.

The Net Book Value ("NBV") for any successive year is the same. There is no impact on NBV and therefore, no impact on Rate Base.

UNDERTAKING NO. JT1.5

TO PROVIDE WHAT THE GROSS FIXED ASSETS WOULD BE WITHOUT THE ADJUSTMENT AT THE TIME OF IFRS.

Response:

As requested, here is Guelph Hydro's PP&E without the IFRS restatement of costs to NBV at the time of transition, January 1, 2010.

Table JT1.5: Restated Gross Fixed Assets without IFRS Transition Adjustment

Guelph Hydro Electric Systems

			IFRS Cost	Cost Grossed Up Reversing IFRS Restatement to NBV		
CCA Class	**OEB**	**Description**	**Opening Balance (NBV as at Jan 1, 2010)**	Cost	Acc'd Dep'n	NBV
N/A	1805	Land	768,123	768,123	0	768,123
CEC	1806	Land Rights	0			0
1	1808	Buildings and Fixtures	15,894,900	18,191,632	(2,296,732)	15,894,900
N/A	1810	Leasehold Improvements	0			0
	1815	Transformer Station Equipment - Normally Primary above 50	0			0
47	1820	Distribution Station Equipment - Normally Primary below 50 k	1,624,259	1,697,266	(73,007)	1,624,259
	1825	Storage Battery Equipment	0	0		0
47	1830	Poles, Towers and Fixtures	13,603,113	20,579,581	(6,976,469)	13,603,113
47	1835	Overhead Conductors and Devices	11,149,245	17,035,390	(5,886,145)	11,149,245
47	1840	Underground Conduit	23,364,939	34,914,467	(11,549,528)	23,364,939
47	1845	Underground Conductors and Devices	22,931,851	33,460,819	(10,528,968)	22,931,851
47	1850	Line Transformers	10,783,462	17,111,497	(6,328,035)	10,783,462
47	1855	Services	4,511,965	6,769,661	(2,257,695)	4,511,965
47	1860	Meters	9,267,122	12,659,803	(3,392,681)	9,267,122
	1865	Other Installations on Customer's Premises	0	0		0
N/A	1905	Land	0	0		0
CEC	1906	Land Rights	0	0		0
1	1908	Buildings and Fixtures	0	0		0
	1910	Leasehold Improvements	0	0		0
8	1915	Office Furniture and Equipment	506,668	1,165,296	(658,628)	506,668
45	1920	Computer Equipment - Hardware	783,664	2,193,680	(1,410,016)	783,664
45.1	1925	Computer Software	0	0		0
10	1930	Transportation Equipment	1,284,008	2,687,174	(1,403,166)	1,284,008
	1935	Stores Equipment	54	96,338	(96,284)	54
8	1940	Tools, Shop and Garage Equipment	404,817	940,008	(535,192)	404,817
	1945	Measurement and Testing Equipment	2,974	14,872	(11,898)	2,974
	1950	Power Operated Equipment	0	0		0
	1955	Communication Equipment	0	0		0
	1960	Miscellaneous Equipment	209,103	2,327,700	(2,118,596)	209,103
	1970	Load Management Controls - Customer Premises	136,371	314,982	(178,610)	136,371
	1975	Load Management Controls - Utility Premises	0	0		0
47	1980	System Supervisory Equipment	233,890	304,281	(70,392)	233,890
	1985	Sentinel Lighting Rentals	6,158	6,158		6,158
	1990	Other Tangible Property	0	0		0
47	1995	Contributions and Grants	(25,763,528)	(31,794,646)	6,031,118	(25,763,528)
		PP&E Account	0	0		0
	2070	Other Utility Plant	398	771	(373)	398
Total before Work in Process / Re-allocation of amortization			**91,703,557**	**141,444,852**	**(49,741,295)**	**91,703,557**
95	2055	Work in Process	150,530	150,530		150,530
		Re-allocation of amortization				
		Total after Work in Process	**91,854,087**	**141,595,382**	**(49,741,295)**	**91,854,087**
				Per continuity schedule		91,854
				Per Audited FS		91,854
						0

UNDERTAKING NO. JT1.6

TO PROVIDE THE LIST OF ACTIONS REFERENCED IN 1-SEC-5

Response:

Guelph Hydro presented the list of actions during the technical conference (please see the Transcript, page 63 line 24 to 28 and page 64 line 1 to 2). An extract from the Transcript follows:

"PRELIMINARY MATTERS:

MR. VELLONE: I do have some preliminary items. The first is in respect of Undertaking JT1.6. Our understanding in that undertaking was it was a request to provide a list of certain actions taken in response to customer engagement activities. That can be found in the application, Exhibit 1, Appendix 2-A-C, and I think it's actually what's showing up on the screen right now."

For more clarity, Appendix 2-AC can be found in the Application, Exhibit 1, Tab 4, Schedule 4, Table 1-47, page 46.

More detailed actions are presented in the Application, Exhibit 1, Tab 4, Schedule 4, page 6 to 27.

UNDERTAKING NO. JT1.7

TO RECALCULATE THE FIGURES PROVIDED ON ROE WITH ADJUSTMENTS.

Response:

The schedule below summarizes the recalculated ROE figures with adjustments.

Guelph Hydro			
EB-2015-0073			
JT1.7 Recalculate ROE Figures w Adjustments			
	2012	**2013**	**2014**
Regulated Net Income	$ 5,365,000	$ 4,897,000	$ 7,488,000
Remove:			
Future Deferred Taxes	-29,796	-1,129,805	-766,873
Non rate regulated items	-61,603	27,377	-26,697
Adjustment to interest for deemed debt	689,503	842,272	863,553
Adjusted Regulated Net Income (WCA @15%)	$ 4,766,896	$ 5,157,156	$ 7,418,017
Revenue requirement reduction due to reduction in rate base @ 7.5% WCA	-840,276	-932,552	-1,005,380
Reduction in PILS due to above reduction in revenue requirement	177,550	197,048	212,437
Adjusted Regulated Net Income (WCA @7.5%)	$ 4,104,170	$ 4,421,652	$ 6,625,074
Working Capital Allowance @ 15%	**2012**	**2013**	**2014**
Rate Base	**$ 139,600**	**$ 144,607**	**$ 148,536**
Deemed Equity	**$ 55,840**	**$ 57,843**	**$ 59,414**
After Tax Profit	**$ 4,767**	**$ 5,157**	**$ 7,418**
ROE	**8.54%**	**8.92%**	**12.49%**
Working Capital Allowance @ 7.5%	**2012**	**2013**	**2014**
Rate Base	**$ 127,243**	**$ 130,893**	**$ 133,751**
Deemed Equity	**$ 50,897**	**$ 52,357**	**$ 53,500**
After Tax Profit	**$ 4,104**	**$ 4,422**	**$ 6,625**
ROE	**8.06%**	**8.45%**	**12.38%**

UNDERTAKING NO. JT1.8

TO PROVIDE THE DEVELOPMENT PLAN REFERENCED IN 1-SEC-16, WHEN COMPLETED.

Response:

Both the Development Plan for shared services as well as the Strategic Plan for GHESI are under development and will not be finalized until Q4 2015. Guelph Hydro will file its strategic plan along with the development plan once they are approved by GHESI's Board of Directors. These documents may not be approved at the same time.

UNDERTAKING NO. JT1.8 (REVISED)

TO PROVIDE THE STRATEGIC PLAN, WHEN AVAILABLE.

Response:

Please see the response to JT1.8.

UNDERTAKING NO. JT1.9

TO PROVIDE A CALCULATION OF THE CHANGE IN OM&A EXPENSES FROM 2015 TO 2016 THAT SEPARATES THE LABOR COMPONENT OF OM&A FROM THE NON LABOUR COMPONENT, NETS OUT ESTIMATED GROWTH AND PRODUCTIVITY, AND APPLIES A MEASURE OF INFLATION TO THESE NET OM&A AMOUNTS TO DETERMINE WHAT THE INCREASE IN OM&A WOULD HAVE BEEN UNDER THIS ANALYSIS

Response:

This undertaking response refers extensively to the table below. Accordingly, for ease of reference, the rows and columns in the table have been numbered.

Guelph Hydro is using the following assumptions in responding to this Undertaking:

1. The simple average GDP-IPI used by the OEB to set 2013, 2014, and 2015 IRM rates of 1.833% (average of 2.2%, 1.7% and 1.6%).= has been used as the measure of inflation.
2. Guelph Hydro has not explicitly factored in productivity into the calculations as the company believes that it has already reflected productivity improvements into its OM&A numbers in both 2015 and 2016. In any case, the IRM productivity factor in the OEB's IRM rate determination for 2014 and 2015 was set at nil.
3. The labour and benefits shown in column (5) include the impact of the new positions that Guelph Hydro is seeking in this application.

Analysis:

- For completeness, Guelph Hydro is showing the same reconciliation of "budget" OM&A with its "revenue requirement" OM&A as has been done for JT1.1. The reconciliation for 2015 and 2016 is carried out in rows 17 through 35 in column (1) for 2015 and in rows 17 through 35 in column (4) for 2016.
- The labour & benefits component of OM&A is separated from the non-labour & benefits component of OM&A in columns (2) and (3) for 2015 and columns (5) and (6) for 2016.
- Columns (7) and (8) show the percent increase for each Department for the labour & benefits component and for the non-labour & benefits component. The

overall increase in the labour & benefits component from 2015 to 2016 is 6.05% and the overall increase in the non-labour & benefits portion of OM&A is 1.56%.

- Columns (9) and (10) then apply the average GDP-IPI increase to the 2015 labour & benefits OM&A and to the non-labour & benefits OM&A to derive a "GDP-IPI OM&A". This new derived OM&A is then adjusted using the same reconciliation methodology used to adjust the 2015 and 2015 "budget" OM&A to derive the "revenue requirement" OM&A, by applying the same 1.833% increase to most of the 2015 adjustments. The exceptions to this were to the one-time adjustments that Guelph Hydro is seeking to recover in its 2016 application such as the one-time impact of monthly billing. These amounts were carried over as-is into the adjustment column.
- The impact of this exercise is that by applying an inflation factor to the labour and non-labour components of Guelph Hydro's 2015 OM&A, the 2016 revenue requirement OM&A reduces by $367,727 from $16,404,861 to $16,037,134.
- Clearly, this demonstrates that, as Guelph Hydro has noted in its evidence and at the Technical Conference, much of the labour & benefits portion of the sought-after increase in revenue requirement is being driven by the impact of new positions that are needed by the company to deal with retirements, Smart Grid development to meet OEB regulations and a general increase in the company's workload (please also see E4/T1/S1 pages 2 through 4).
- What is equally clear is that, with the non-labour & benefits component of Guelph Hydro's costs increasing by only 1.56%, Guelph Hydro is effectively controlling this component of its OM&A costs with these costs expected to increase **below** the 2013-2015 average GDP-IPI rate of inflation in 2016.

Table JT1.9: Inflation Factor

		2015			2016						
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Department	**Total**	**Labour & Benefits**	**OM&A net of Labour**	**Total**	**Labour & Benefits**	**OM&A net of Labour**	**Labour & Benefits Increase**	**OM&A Net of Labour Increase**	**OM&A Increase per Average GDP-IPI 2013-2015 -- Labour & Benefits; 1.833%**	**OM&A Increase per Average GDP-IPI 2013-2015 -- OM&A Net of Labour & Benefits; 1.833%**
1	**TOTAL OPERATIONS**	5,037,127	3,026,016	2,011,111	5,569,496	3,427,611	2,141,884	13.27%	6.50%	$ 3,081,483	$ 2,047,975
2											
3	**TOTAL MAINTENANCE**	2,114,207	-	2,114,207	2,287,297	-	2,287,297	n/a	8.19%	-	2,152,961
4											
6	**TOTAL ADMINISTRATION**	4,874,520	3,094,403	1,781,117	4,665,560	3,138,655	1,526,905	1.43%	-14.27%	3,151,124	1,813,765
5											
7	**TOTAL BILLING**	2,237,624	1,447,337	790,288	2,333,193	1,497,199	835,994	3.45%	5.78%	1,473,866	804,774
8											
9	**TOTAL CREDIT**	555,159	340,119	215,040	563,084	347,994	215,090	2.32%	0.02%	346,353	218,982
10											
11	**TOTAL INFORMATION SYSTEMS**	1,393,790	720,390	673,400	1,434,835	738,761	696,074	2.55%	3.37%	733,595	685,743
12											
13	**TOTAL OM&A per BUDGET**	**16,212,428**	**8,628,266**	**7,585,163**	**16,853,465**	**9,150,220**	**7,703,244**	6.05%	1.56%	**8,786,422**	**7,724,199**
14											
15	**TOTAL OM&A per Rate Filing**	**$ 15,333,069**			**$ 16,404,861**					**GDP-IPI OM&A**	**$ 16,510,621**
16											
17	**Reconciliation of Difference:**			**Reconciliation of Difference:**						**Reconciliation of Difference:**	
18	2015 Budget OM&A	**$ 16,212,428**		2016 Budget OM&A	**$ 16,853,465**					2016 OM&A after avg. GDP-IPI	**$ 16,510,621**
19											
20	**Less:**			**Less:**						**Less:**	
21	Water Billing Costs	487,081		Water Billing Costs	$ 506,446	3.98%				Water Billing Costs	$ 495,995
22	Board Expenses	-		Board Expenses	10,550	n/a				Board Expenses	10,550
23	Shared Services Expenses	684,458		Shared Services Expenses	679,452	-0.73%				Shared Services Expenses	697,004
24	Property Taxes	330,126		Property Taxes	335,074	1.50%				Property Taxes	336,177
25	Utility Solution Costs, SR&ED Credits	152,711		Utility Solution Costs, SR&ED Credits	143,749	-5.87%				Utility Solution Costs, SR&ED Credits	155,511
26											
27	**Add:**			**Add:**						**Add:**	
28	Monthly Billing	-		Monthly Billing	$ 360,000	n/a				Monthly Billing	$ 360,000
29	Actuarial Adjustments	25,907		Actuarial Adjustments	50,213	93.82%				Actuarial Adjustments	26,382
30	Regulatory Costs of COS	-		Regulatory Costs of COS	63,300	n/a				Regulatory Costs of COS	63,300
31	Shared Services Revenue	749,110		Shared Services Revenue	743,904	-0.69%				Shared Services Revenue	762,819
32	Donations	-		Donations	9,000	n/a				Donations	9,000
33	Other	-		Other	250	n/a				Other	250
34											
35	2015 Revenue Requirement OM&A as filed	**$ 15,333,069**		2016 Revenue Requirement OM&A as Filed	**$ 16,404,861**	6.99%				2016 Revenue Requirement OM&A @ avg. GDP-IPI of 1.833%	**$ 16,037,134**

UNDERTAKING NO. JT1.10

TO PROVIDE THE SOURCE OF THE CALCULATION OF THE NEGATIVE 5 PER CENT EFFICIENCY RATING REFERENCED IN THE RESPONSE TO 1-SEC-1 AT PAGE 37.

Response:

The source for the negative 5 percent efficiency referred in the response to 1-SEC-1 at page 37 is the PEG model released on May 15, 2015 updated with Guelph Hydro's 2014 actual, and 2015 and 2016 budgets. Guelph Hydro filed an Excel version of the model (please see Guelph_TC_Undertakings_JT1_10 file, tabs "Forecasting" and "Forecast Results"). The results of the efficiency rating are presented below. The following table was also provided in Excel version, in the same file, tab "Forecast Results".

Table JT1.10- Efficiency Rating Results using the PEG model

Results for Percent Difference (Logarithmic)	2013	2014	2015	2016	2017	2018	2019
2013-2014 Actual	0.18%	-5.46%	-6.70%	-7.06%	-7.78%	-8.66%	-9.86%
2015-2016 Budget	0.18%	-5.46%	-5.38%	-5.15%	-5.88%	-6.76%	-7.97%
Difference	0.00%	0.00%	-1.31%	-1.91%	-1.90%	-1.90%	-1.89%

Results for Three Year Average Performance	2013	2014	2015	2016	2017	2018	2019
2013-2014 Actual	4.28%	-2.43%	-3.99%	-6.41%	-7.18%	-7.84%	-8.77%
2015-2016 Budget	4.28%	-2.43%	-3.55%	-5.33%	-5.47%	-5.93%	-6.87%
Difference	0.00%	0.00%	-0.44%	-1.07%	-1.71%	-1.90%	-1.90%

UNDERTAKING NO. JT1.11

TO RECONCILE THE RESPONSE IN THE INTERROGATORY, THE $206,349 OF THE ALLOCATED DEPRECIATION IS OM&A, AS COMPARED TO ALL OF THE ALLOCATED DEPRECIATION BEING SHOWN AS OM&A IN TABLE 1-4 IN THE ORIGINAL EVIDENCE, WHICH IS A FIGURE OF $550,440.

Response:

In review of both Table 1-4 in Exhibit 1 of the original evidence (Allocated Depreciation $550,440) and the analysis provided as part of Guelph Hydro's response to IR 2-Energy Probe-8 (Allocated Depreciation that was expensed as OM&A - $206,349), it was determined that the correct amount of fully allocated depreciation that remained in OM&A and therefore should be deducted when calculating Working Capital is in fact $206,349 and not $550,440; which is the Fully Allocated Depreciation amount prior to capitalization.

UNDERTAKING NO. JT1.12

TO CORRECT THE GLOBAL ADJUSTMENT AMOUNT ON TABLE 2-ENERGY PROBE-17-2.

Response:

Guelph Hydro has corrected the Global Adjustment rate to reflect the last OEB's Regulated Price Plan Report issued on April 20, 2015. The updated 2016 Cost of Power is presented below:

Table JT1.12 – 2016 Cost of Power (2-Energy Probe-17-2)

		2016	Test year				%		RPP and Non-RPP Cost of Power		
Class per Load Forecast	**2016 Forecasted Metered kWhs**	**Proposed Loss Factor**	**Kwhs adjusted by DLF**	**RPP Prices**	**HOEP**	**Global Adjustment**	**RPP**	**Non-RPP**	**RPP $**	**Non-RPP $**	**Total Cost Of Power**
Residential	381,586,775	1.0260	391,506,338	0.10210	0.01992	$0.08194	93.95%	6.05%	$37,556,105	$2,411,011	$39,967,116
GS<50kW	150,174,015	1.0260	154,077,873	0.10210	0.01992	$0.08194	83.45%	16.55%	$13,127,876	$2,597,355	$15,725,231
GS 50kW to 999kW	397,678,750	1.0260	408,016,633	0.10210	0.01992	$0.08194	8.05%	91.95%	$3,354,372	$38,214,088	$41,568,459
GS 1000kW to 4999kW	563,100,354	1.0260	577,738,464	0.10210	0.01992	$0.08194	0.00%	100.00%	$0	$58,848,440	$58,848,440
Large Use	276,633,108	1.0260	283,824,341	0.10210	0.01992	$0.08194	0.00%	100.00%	$0	$28,910,347	$28,910,347
Unmetered Scattered Load	1,700,939	1.0260	1,745,156	0.10210	0.01992	$0.08194	0.00%	0.67%	$0	$1,196	$1,196
Sentinel Lighting	21,457	1.0260	22,015	0.10210	0.01992	$0.08194	89.95%	10.05%	$2,022	$225	$2,247
Street Lighting	9,628,070	1.0260	9,878,357	0.10210	0.01992	$0.08194	99.33%	100.00%	$1,001,797	$1,006,209	$2,008,007
TOTAL	**1,780,523,469**		**1,826,809,177**						$55,042,171	$131,988,872	**$187,031,043**

Transmission - Network		Volume	2016		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	391,506,338	$0.0074	$2,911,709
GS<50kW		kWh	154,077,873	$0.0068	$1,050,415
GS 50kW to 999kW		kW	1,037,307	$2.9501	$3,060,183
GS 1000kW to 4999kW		kW	1,194,282	$2.9501	$3,523,277
Large Use		kW	496,250	$3.5626	$1,767,919
Unmetered Scattered Load		kWh	1,745,156	$0.0068	$11,897
Sentinel Lighting		kW	60	$2.1776	$131
Street Lighting		kW	26,693	$2.6201	$69,937
TOTAL					**$12,395,468**

Transmission - Connection		Volume	2016		
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	391,506,338	$0.0058	$2,268,971
GS<50kW		kWh	154,077,873	$0.0051	$791,867
GS 50kW to 999kW		kW	1,037,307	$2.2291	$2,312,285
GS 1000kW to 4999kW		kW	1,194,282	$2.2291	$2,662,200
Large Use		kW	496,250	$2.6917	$1,335,739
Unmetered Scattered Load		kWh	1,745,156	$0.0051	$8,969
Sentinel Lighting		kW	60	$1.6451	$99
Street Lighting		kW	26,693	$1.9794	$52,836
TOTAL					**$9,432,967**

Wholesale Market Service			2016			
Class per Load Forecast			**Test Year**			
Residential		kWh	391,506,338	$0.0044	$1,722,628	
GS<50kW		kWh	154,077,873	$0.0044	$677,943	
GS 50kW to 999kW		kWh	399,827,453	$0.0044	$1,759,241	*Excludes WMP forecast
GS 1000kW to 4999kW		kWh	577,738,464	$0.0044	$2,542,049	
Large Use		kWh	283,824,341	$0.0044	$1,248,827	
Unmetered Scattered Load		kWh	1,745,156	$0.0044	$7,679	
Sentinel Lighting		kWh	22,015	$0.0044	$97	
Street Lighting		kWh	9,878,357	$0.0044	$43,465	
TOTAL			**1,818,619,997**		**$8,001,928**	

Rural Rate Assistance			2016			
Class per Load Forecast			**Test Year**			
Residential		kWh	391,506,338	$0.0013	$508,958	
GS<50kW		kWh	154,077,873	$0.0013	$200,301	
GS 50kW to 999kW		kWh	399,827,453	$0.0013	$519,776	*Excludes WMP forecast
GS 1000kW to 4999kW		kWh	577,738,464	$0.0013	$751,060	
Large Use		kWh	283,824,341	$0.0013	$368,972	
Unmetered Scattered Load		kWh	1,745,156	$0.0013	$2,269	
Sentinel Lighting		kWh	22,015	$0.0013	$29	
Street Lighting		kWh	9,878,357	$0.0013	$12,842	
TOTAL			**1,818,619,997**		**$2,364,206**	

2016	**Test Year**
4705-Power Purchased	$187,031,043
4708-Charges-WMS	$8,001,928
4714-Charges-NW	$12,395,468
4716-Charges-CN	$9,432,967
4730-Rural Rate Assistance	$2,364,206
4750-Low Voltage	$29,301
4751 - SME	515,169
TOTAL	**219,770,081**

UNDERTAKING NO. JT1.13

TO RECONCILE THE AMOUNTS AT TABLE 2-ENERGY PROBE-18 (A) AND (B), WITH THE CONTINUITY SCHEUDLE.

Response:

In the following tables, Guelph Hydro has reconciled capital expenditures in 2-Energy Probe-18 a) with both the capital additions in 2-Energy Probe-18 b) and the Continuity Schedules in Table 2-5 – 2-7 in the original evidence for years 2012 - 2014.

The reconciliation for year 2015 and 2016 can be found as part of Undertaking No. JT1.1.

Table JT1.13-1: 2012 Capital Expenditures and Continuity Schedule Reconciliation

Capital Expenditure Reconciliation between Capital Expenditures (2 EP 18 a) and Capital Additions (2 EP 18 b) and Capital Additions in Continuity Schedules (Table 2-5 (2012) and 2-7 (2014))	
Fiscal Year: 2012	
Revised Capital Expenditures included in Cost of Service Filing before Contributed Capital as per Exhibit 2 (Table 2-21) and 2 Energy Probe 18 a) (Net change in General Plant CWIP is already reflected in the General Plant Expenditures)	11,680
Addback: Opening CWIP Distribution System	1,616
Less: Closing CWIP Distribution System	(1,061)
Gross Capital Additions Rolled into Rate base prior to Contributed Capital as per 2 Energy Probe 18 b)	12,235
Less: Contributed Capital	(2,681)
Net Capital Additions Rolled into Rate base as per the Continuity Schedule (Table 2-8) (Before Closing CWIP which is not part of Rate Base)	9,554

Table JT1.13-2: 2013 Capital Expenditures and Continuity Schedule Reconciliation

Fiscal Year: 2013	
Revised Capital Expenditures included in Cost of Service Filing before Contributed Capital as per Exhibit 2 (Table 2-21) and 2 Energy Probe 18 a) (Net change in General Plant CWIP is already reflected in the General Plant Expenditures)	11,466
Addback: Opening CWIP Distribution System	1,061
Less: Closing CWIP Distribution System	(2,867)
Gross Capital Additions Rolled into Rate base prior to Contributed Capital as per 2 Energy Probe 18 b)	9,660
Less: Contributed Capital	(3,269)
Net Capital Additions Rolled into Rate base as per the Continuity Schedule (Table 2-8) (Before Closing CWIP which is not part of Rate Base)	6,391

Table JT1.13-3: 2014 Capital Expenditures and Continuity Schedule Reconciliation

Fiscal Year:	2014	
Revised Capital Expenditures included in Cost of Service Filing before Contributed Capital as per Exhibit 2 (Table 2-21) and 2 Energy Probe 18 a) (Closing CWIP General Plant is included in Capital Expenditures, so need to be removed during reconciliation process)		13,223
Addback: Opening CWIP Distribution System		2,867
Less: Closing CWIP Distribution System		(4,551)
Less: Closing CWIP General Plant		(606)
Gross Capital Additions Rolled into Rate base prior to Contributed Capital as per 2 Energy Probe 18 b)		10,933
Less: Contributed Capital		(2,372)
Net Capital Additions Rolled into Rate base as per the Continuity Schedule (Table 2-8) (Before Closing CWIP which is not part of Rate Base)		8,561

UNDERTAKING NO. JT1.14

TO PROVIDE COMPARISONS OF CAPITAL ADDITIONS, BUDGETED AND ACTUAL FOR EACH OF THE STATED YEARS.

Response:

In the following table, Guelph Hydro has provided a Budget to Actual comparison for capital additions rolled into the rate base.

2011-2014 budget amounts reflect the forecasted capital expenditure budgets reflecting the impact of the change in CWIP, using actual opening and closing CWIP balances.

2015 budget amounts reflect the forecasted capital expenditure budgets reflecting the impact of the change in CWIP, using the actual opening CWIP amount and a forecasted closing CWIP amount.

The capital addition balances presented are gross capital additions and do not reflect the impact of contributed capital.

Refer to Undertaking JT1.20 for the explanation regarding the variance in capital spending compared to budget during fiscal years 2013 and 2014.

Table JT1.14: Table 2-21 including Budgets

Original Table 2-21 (Exhibit 2, Tab 2, Schedule 2
Capital Additions Rolled into Rate Base v. Budget (Capital Additions)

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan & actual)														
	2011			2012			2013			2014			2015 Bridge Year		
	2011 Budget presented in 2012 COS	Actual Cap Add'ns	Var	Cap Addns based on 2012 Approved COS Budget	Actual Cap Add'ns	Var	Cap Add'ns based on Cap Expend. Approved by BOD	Actual Cap Add'ns	Var	Cap Add'ns based on Cap Expend. Approved by BOD	Actual Cap Add'ns	Var	Cap Add'ns based on Cap Expend. Approved by BOD	Forecast Cap Add'ns	Var
			%			%			%			%			%
System Access	4,483,498	6,132,126	136.8%	4,768,070	5,278,625	110.7%	4,417,654	3,483,609	78.9%	4,631,888	4,128,856	89.1%	7,446,881	7,282,743	97.8%
System Renewal	2,320,184	1,537,300	66.3%	2,957,539	2,668,070	90.2%	3,085,038	2,331,569	75.6%	3,212,706	3,148,591	98.0%	4,334,904	4,932,601	113.8%
System Service	12,714,487	15,760,986	124.0%	2,982,337	3,302,818	110.7%	2,646,353	2,624,396	99.2%	3,629,535	1,901,736	52.4%	4,894,108	4,786,236	97.8%
General Plant	1,113,798	1,052,721	94.5%	1,131,116	984,738	87.1%	1,212,000	1,220,577	100.7%	1,569,001	1,753,804	111.8%	2,318,634	2,818,337	121.6%
TOTAL EXPENDITURE	20,631,968	24,483,133	118.7%	11,839,061	12,234,250	103.3%	11,361,045	9,660,151	85.0%	13,043,130	10,932,987	83.8%	18,994,527	19,819,918	104.3%

UNDERTAKING NO. JT1.15

TO COMPARE THE SYSTEM OPERATIONS AND MAINTENANCE COST REFERENCED IN 2-SEC-23 AND EXHIBIT 2, TAB 2, SCHEDULE 4, PAGE 2.

Response:

In the following tables, Guelph Hydro has reconciled the System Operations and Maintenance costs referenced in 2-SEC-23 with Exhibit 2, Tab 2, Schedule 4 (Overhead Expenses Table 2-64) as submitted as part of the original evidence.

Table JT1.15-1: System Operations & Maintenance Reconciliation Table 1

System Operations & Maintenance Reconciliation	Table 1						
		2012	2013	2014	2015	2016	
Per Table 2-SEC-23		5,619,519	6,425,264	6,784,094	7,186,934	7,856,913	
Final year-end adjustments in GL (2014) not included in 2-SEC-23 balance				(256,471)			Note 1
CDM-related costs to be funded by IESO/OPA re-allocated out of OM&A					(152,100)	(111,120)	Note 2
				6,527,623	7,034,834	7,745,793	
Less:	Cost centres separately disclosed in table 2-64 Overhead expenses						
	Engineering O&M	(1,313,201)	(956,079)	(1,067,360)	(978,724)	(1,045,795)	
	Stores	(294,422)	(376,378)	(369,736)	(420,419)	(436,453)	
	Fleet Burden	(251,424)	(304,436)	(288,879)	(294,786)	(309,055)	
							Note 3
Add:	Cost centre included in table 2-64 Overhead expenses						
	Information systems	1,391,396	1,211,739	916,142	1,393,791	1,427,835	
Add/(Less):	Other differences						
Line Construction	Removal of Property Taxes	(90,147)	(92,314)	(90,400)	(91,256)	(93,133)	Note 4
Distribution Station	Removal of Property Taxes	(15,375)	(20,254)	(19,002)	(18,059)	(18,330)	Note 4
System Operation	Missed account in 2-SEC-23 balance	4,971					Note 5
Distribution Meters	Missed account in 2-SEC-23 balance	(2,699)					Note 5
Energy Services	Missed account in 2-SEC-23 balance	(12,435)					Note 5
Balance per Table 2-64 (Exhibit 2 in original evidence)		5,036,183	5,887,542	5,608,387	6,625,382	7,270,862	

In reviewing the reconciliation, it was determined that the primary differences were as follows:

Note 1:

In 2014, the System Operations & Maintenance costs referenced in Table 2-SEC-23 included preliminary balances instead of the final year end balances. The Overhead Expenses Table 2-64 in Exhibit 2 of Guelph Hydro's pre-filed evidence incorporates the final year end balances for 2014. Accordingly, this difference was deducted from the starting balance of Table 2-SEC-23 for this reconciliation to update those costs to final.

Note 2:

In 2015 & 2016, there were adjustments made to the budget to remove some CDM-related costs that are funded through the IESO/OPA from Guelph Hydro's O&M costs. The System Operations & Maintenance costs referenced in 2-SEC-23 used the unadjusted budget prior to these re-allocations. These amounts were also deducted from the starting balance of Table 2-SEC-23 for this reconciliation.

Note 3:

In the response to 2-SEC-23, there were 3 cost centres (Engineering O&M, Stores and Fleet) that were part of the balance in Table 2-SEC-23, but which balances were not part of the System Operations & Maintenance line item in Exhibit 2 (Overhead Expense Table 2-64) in Guelph Hydro's pre-filed evidence. These cost centres were not included as part of the System Operation & Maintenance costs in the Overhead expense Table 2-64, because these costs were separately disclosed in the same Table under Fleet, Engineering and Stores. Because of this, these costs are required to be deducted from starting balance in Table 2-SEC-23.

Additionally, Exhibit 2 (Overhead Expenses Table 2-64) also included costs of an additional cost centre (Information Systems) in the System Operations & Maintenance line item that is not part of the System Operations & Maintenance costs outlined in Table 2-SEC-23. These costs are required to be added to the starting balance of Table 2-SEC-23.

Note 4:

To keep the Overhead expense Table 2-64 consistent with the reporting of Controllable OM&A per Guelph Hydro's pre-filed evidence, Guelph Hydro removed property taxes from the individual costs centres that received a portion of this cost for internal reporting purposes. The System Operation & Maintenance costs referenced in Table 2-SEC-23 did not remove the property tax costs that related to these cost centres.

As a result, property taxes that were included in both the Line construction and Distribution station equipment cost centres are required to be deducted from the starting balance of Table 2-SEC-23 as other costs centres (Stores and Fleet) with a property tax allocation were already removed from the starting balance of Table 2-SEC-23 as outlined in the first bullet point above.

Note 5:

In 2012, there were some minor reconciling items in various cost centres as certain management reports used in preparing Table 2-SEC-23 did not include new General Ledger accounts that were included when preparing the Overhead expenses Table 2-64 of Guelph Hydro's pre-filed evidence.

Guelph Hydro has included a second table, Table 2, below which shows a detailed reconciliation for the 3 cost centres being deducted from the System Operation & Maintenance costs referenced in Table 2-SEC-23 to the separately disclosed line items outlined on the Overhead expenses Table 2-64 found in Exhibit 2 of the pre-filed evidence.

Guelph Hydro also notes that the Overhead expenses Table 2-64 submitted as part of the pre-filed evidence includes all overhead expenses prior to capitalization and not just final OM&A costs. Therefore, Table 2, below starts with the O&M costs associated with each cost centre and adds the overhead costs that were capitalized as part of Guelph Hydro's capitalization process.

To reiterate, Guelph Hydro notes that two cost centres — Stores and Fleet — needed to have the allocated property tax costs removed from their balances similar to the adjustment described in the third bullet above in order to reconcile to Table 2-64 in Exhibit 2 of Guelph Hydro's pre-filed evidence.

1
Table JT1.15-2: System Operations & Maintenance Reconciliation Table 2

System Operations & Maintenance Reconciliation		Table 2					
			2012	2013	2014	2015	2016
Engineering	Per amount in 2-SEC-23 build up		1,313,201	956,079	1,067,360	978,724	1,045,795
	Missed account in 2-SEC-23 bal and budget adjust.		2,385			(40,212)	(9,749)
	O&M per Table 2-64		1,315,586	956,079	1,067,360	938,512	1,036,046
	Capitalized costs re Engineering Table 2-64		443,734	467,885	520,500	579,126	510,007
	Per amount included on Table 2-64		1,759,320	1,423,964	1,587,860	1,517,638	1,546,053
Stores	Per amount in 2-SEC-23 build up		294,422	376,378	369,736	420,419	436,453
	Property taxes		(41,617)	(41,761)	(40,895)	(36,509)	(42,131)
	Per amount included on Table 2-64		252,805	334,617	328,841	383,910	394,322
Fleet Burden	Per amount in 2-SEC-23 build up		251,424	304,436	288,879	294,786	309,055
	Property taxes		(84,165)	(85,720)	(83,943)	(85,703)	(86,480)
	O&M per Table 2-64		167,259	218,716	204,936	209,083	222,575
	Capitalized costs re Fleet Table 2-64		538,363	620,624	688,403	736,272	648,397
	Per amount included on Table 2-64		705,622	839,340	893,339	945,355	870,972

2

UNDERTAKING NO. JT1.16

TO PROVIDE THE HISTORICAL REACTIVE CAPITAL BUDGET FOR THE YEARS 2011 TO 2015 AND THE FORECASTS FOR 2016 TO 2020.

Response:

As described in IR response 2-Staff-34, “the system renewal expenditure forecasts predicts that some assets will fail abruptly and will need to be replaced in a reactive manner.” However, due to the unpredictable nature of the failures leading to reactive replacement, Guelph Hydro cannot accurately forecast a quantity of each asset type that will need to be replaced in a reactive manner each year. Guelph Hydro uses the ACA and historical experience to inform overall system replacement budgets, and includes some budget space for assumed reactive replacements, among other activities that do not fall within specific projects in the system renewal plan. The table below includes reactive capital expenditures for the years 2011 to 2014 and for 2015 (as of July 24, 2015). The table also includes the 2015 budget item within which reactive replacements (as well as other costs) would fall. The table then includes the same item forecasted for 2016-2020.

Table JT1.16: Reactive Capital Expenditures

Year	Expenditures (2011-2015 YTD), Budget (2015), Forecasts (2016-2020)
2011	$104,382.70
2012	$197,902.10
2013	$225,970.90
2014	$246,568.70
2015 YTD (as of July 24, 2015)	$102,380.20
2015 Budget	Part of $186,200
2016 Forecast	Part of $171,700
2017 Forecast	Part of $157,100
2018 Forecast	Part of $142,600
2019 Forecast	Part of $128,100
2020 Forecast	Part of $113,500

UNDERTAKING NO. JT1.17

TO PROVIDE THE 2011 AND 2013 ASSET CONDITION ASSESSMENT DOCUMENT.

Response:

The 2011 and 2012 ACAs are filed in Appendix JT1.17.

There is ambiguity in the terms "2013 ACA" and "2012 ACA". You will note the report is titled "2012 Asset Condition Analysis", this is because the data used is as of the 12/31/2012. However, the report was formulated throughout 2013 and completed in November 2013 and is often internally referred to as the 2013 ACA. This is the reason for discrepancy. Guelph Hydro cannot provide a "2013 ACA" as this does not exist. Guelph Hydro only has 2011, 2012 and 2014 ACAs.

UNDERTAKING NO. JT1.18

TO CONFIRM WHETHER OR NOT A CALCULATION BY REPLACEMENT FREQUENCY FOR A REPLACEMENT RATE BY ASSET TYPE CAN BE DONE.

Response:

Guelph Hydro does have the ability to produce the same table from 2-SEC-48 as of the end of 2011 using its GIS system. However, because Guelph Hydro does not track which new assets are replacing assets taken out of service, it is not known when comparing the data whether the assets were replaced or simply retired from service. Data can be calculated to determine what assets that were at or beyond TUL are no longer in service in 2014 but this comparison would provide an asset retirement rate rather than an asset replacement rate. Additionally, the table from 2014 in the 2-SEC-48 response could not be directly compared to a 2011 table because the table from 2014 includes assets which reached TUL since 2011.

Guelph hydro uses the levelized 20-year replacement plan from the asset condition assessment to determine the optimal replacement frequency for its assets. The capital plans for each year are designed such that the projects being undertaken will result in the replacement of approximately the number of assets shown in the table of each asset type for proactively replaced assets. A table depicting the number of units planned for replacement from 2015-2020 can be found in the response to 2-SEC-47.

UNDERTAKING NO. JT1.19

TO PROVIDE THE ACTUAL EXCEL SPREADSHEETS REFERENCED IN 2-SEC-51, 52, 55, AND 56.

Response:

Guelph Hydro has filed with this response live Excel versions of the spreadsheets referenced in 2-SEC-51, 52, 55, and 56.

Please see:

- Guelph_TC_Undertakings_JT1_19_2-SEC-51_20150821,
- Guelph_TC_Undertakings_JT1_19_2-SEC-52_20150821,
- Guelph_TC_Undertakings_JT1_19_2-SEC-55 and 2-SEC-56_20150821

UNDERTAKING NO. JT1.20

TO PROVIDE THE FINAL BUDGETED AMOUNTS FOR THE 2012 RATE APPLICATION.

Response:

Attached is Appendix 2-AB updated to include 2013 and 2014 internal capital expenditure budgets along with a variance analysis between the updated internal 2013 and 2014 capital expenditure budgets vs 2013 and 2014 actual capital expenditures respectively.

Table JT1.20-1: Updated Appendix 2-AB to include 2012 Budget

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period												Forecast Period (planned)				
	2011 (Previous Bridge Year)		2012 (Previous Test Year)		2013			2014			2015 Bridge Year						
	2011 Budget presented in 2012 COS	Actual	2012 Board Approved Budget Presented in 2012 COS	Actual	2013 Budget presented in 2012 COS	2013 GHESI Updated Budget	Actual	2014 Budget presented in 2012 COS	2014 GHESI Updated Budget	Actual	Budget / forecast	2015 Year to Date Actuals (Jan-June)	2016 Test Year	2017	2018	2019	2020
System Access	4,854,708	6,574,742	4,521,093	5,018,365	5,203,746	5,203,746	4,229,054	5,359,945	5,307,645	4,886,595	5,846,937	2,874,528	5,397,045	5,496,506	5,670,452	5,829,015	5,982,336
System Renewal	2,512,283	1,648,262	2,804,344	2,536,522	2,884,000	3,634,000	2,830,493	2,971,000	3,720,520	3,726,430	3,960,130	1,149,503	4,478,934	4,613,302	4,751,701	4,894,252	5,041,080
System Service	13,767,179	16,898,611	2,827,857	3,139,974	2,367,254	3,117,254	3,185,982	2,438,055	4,203,235	2,250,748	3,842,621	1,534,009	1,858,400	1,914,152	1,971,576	2,030,724	2,091,645
General Plant	1,189,000	1,052,721	1,185,188	984,738	1,125,000	1,212,000	1,220,577	1,235,000	2,045,360	2,359,438	2,212,704	538,094	2,195,685	1,431,505	1,474,450	1,518,684	1,564,244
TOTAL EXPENDITURE	22,323,170	26,174,335	11,338,482	11,679,598	11,580,000	13,167,000	11,466,106	12,004,000	15,276,760	13,223,211	15,862,392	6,096,133	13,930,063	13,455,465	13,868,179	14,272,674	14,679,305
System Operations	N/A	3,201,673	N/A	3,774,224	N/A	N/A	4,052,048	N/A	N/A	4,816,000	5,057,727	1,825,752	5,569,496	5,647,468	5,726,533	5,806,704	5,887,998
System Maintenance	N/A	2,177,753	N/A	1,845,295	N/A	N/A	2,373,216	N/A	N/A	1,968,000	2,129,207	688,926	2,287,417	2,319,441	2,351,913	2,384,840	2,418,228
System O&M	N/A	5,379,426	N/A	5,619,519	N/A	N/A	6,425,264	N/A	N/A	6,784,094	7,186,934	2,514,678	7,856,913	7,966,910	8,078,446	8,191,545	8,306,226

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed — 2014 are full year actual results
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): idge Year - Year to dates actuals for Capital include 6 months, year to date actuals for O&M include 5

2013 Capital Expenditures Variance Analysis:

Table JT1.20-2: 2013 GHESI Updated Budget Vs 2013 Actual

CATEGORY	2013		
	2013 Budget presented in 2012 COS	2013 GHESI Updated Budget	Actual
System Access	5,203,746	5,203,746	4,229,054
System Renewal	2,884,000	3,634,000	2,830,493
System Service	2,367,254	3,117,254	3,185,982
General Plant	1,125,000	1,212,000	1,220,577
TOTAL EXPENDITURE	11,580,000	13,167,000	11,466,106

The main drivers behind the variances between the 2013 updated internal capital expenditures budget and 2013 actual capital expenditures are related to a decrease in projects related to distribution system relocations to accomodate work due to municipal and provincial land owners infrastructure projects, accounting for a variance of ($429,407). A decrease in projects related to system modifications to accomodate customers which accounted for a variance of ($642,116) budget to actual. The final major variance between the 2013 updated capital budget and the 2013 capital expenditures is related to system renewal projects where Guelph Hydro experienced a delay in implementing the replacement of obsolence pole-transformers in 2013 and the project was delayed to the 2014 year due to civil contractor availability. The variance for the system renewal updated budget to actuals was ($803,507).

2014 Capital Expenditures Variance Analysis:

Table JT1.20-3: 2014 GHESI Updated Budget Vs 2013 Actual

CATEGORY	2014		
	2014 Budget presented in 2012 COS	2014 GHESI Updated Budget	Actual
System Access	5,359,945	5,307,645	4,886,595
System Renewal	2,971,000	3,720,520	3,726,430
System Service	2,438,055	4,203,235	2,250,748
General Plant	1,235,000	2,045,360	2,359,438
TOTAL EXPENDITURE	12,004,000	15,276,760	13,223,211

The main drivers behind the variances between the 2014 updated internal capital budget and the 2014 actual capital expenditures are related to projects within the system service area. A delay in the execution of the upgrade and rebuild of Rockwood MS#1, which was scheduled to begin in 2014, did not occur and the project was delayed to 2015 with a scheduled in-service date of October 2015. The amount of this variance is ($1,2650,000). The other variance between budget and actual is due to a project related to SmartGrid. Guelph Hydro provided information in Interrogatory Response to 2-Staff-12 (a), where Guelph Hydro described some of its actual as well as proposed investments and activities related to "smart grid" development, replicated as follows for convenience:

"Over the years Guelph Hydro has also participated in a number of efforts to further innovate and support smart grid enhancement and expansion. The following is a partial list of potential projects supported by Guelph Hydro through collaboration with various third parties:

- 2015 – working with Canadian Solar to provide in kind support and participation in the development of a MicroGrid test lab and research facility to be located in Guelph;

- 2015 – worked with Canadian Solar to respond to an IESO Energy Storage RFP to build and support the operation of energy storage technologies to be located at Guelph Hydro's Arlen MTS;
- 2014 – worked with S&C Electric to respond to an IESO Energy Storage RFQ;
- 2013 – collaborated with Silver Spring Networks Inc. in the development and submission of a Data Analytics Proposal to the Smart Grid Fund.."

Guelph Hydro's 2014 SCADA/OT capital budget included a $500k placeholder reserved for Guelph Hydro's contribution towards the two separate potential "smart grid" projects identified above, specifically a Data Analytics Proposal submission to the Ontario Smart Grid Fund in collaboration with Silver Spring Networks Inc., and a submission to the IESO's Energy Storage RFQ in collaboration with S&C Electric. Unfortunately, neither of these submission proposals were accepted, resulting in a $500k variance in SCADA/OT budget to actual.

UNDERTAKING NO. JT1.21

TO DETERMINE HOW THE ALPHA AND BETA WERE CHOSEN AND TO PROVIDE STATISTICAL EVIDENCE TO SUPPORT THE USEFUL LIFE, STATISTICAL EVIDENCE TO SUPPORT THE SELECTION OF THE USEFUL LIFE, AND IN ADDITION, TO EXPLAIN WHETHER THE CURVE HERE AND THE DISCUSSION REFERS TO AN EXAMPLE OF WHETHER IT REFERS TO AN ACTUAL SITUATION IN GUELPH HYDRO.

Response:

Guelph Hydro has corrected the text from Exhibit 2, Appendix 2-A, Appendix D, page 438 to read as follows:

"Assuming that at the ages of 50 and 60 years the probability of failure (pf) for this asset are 20% and 95% respectively results in the survival curve shown below."

Kinectrics determined that the ages of 50 and 60 years correspond the cumulative probabilities of failure of 20% and 95% respectively; the analogous survival rates are 80% and 5% respectively.

The alpha and beta values for wood poles are 61 and 0.259, respectively.

Comprehensive statistical information is not available. Because of limited data, the survival function was based on the premise that the failure rate for the asset exponentially increases with age. The parameters that shape the function (alpha and beta) are calculated based on the published document "Asset Depreciation Study for the Ontario Energy Board" and on an analysis of Guelph Hydro's wood pole population age distribution. The OEB asset study indicates that the wood poles in Ontario have a typical useful life of 45 years. Analysis of Guelph Hydro's population of wood poles showed the following: 21% are 45 years or older, 13% are 50 years or older, and 0.5% are 65 years or older. Since a large portion of the population was older than 45 years, an optimistic survival rate of 80% at 50 years was selected. While only 0.5% of poles are in fact 65 or older, an optimistic value of 5% survival was selected. The two ages and their corresponding survival rates were used to calculate the parameters of the survival function.

The CPF score and survival function vs. age are calculated based on actual Guelph Hydro's population distribution.

UNDERTAKING NO. JT1.22

TO PROVIDE THE PORTION OF COSTS BORNE BY THE CITY IN 2012 FOR EACH OF THE YEARS.

Response:

Please see updated table below.

Table JT1.22- Table 4-VECC-38-d

Year	Meter Reading Contract	Total Costs/Water billing	% borne by City of Guelph
2012	$266,648	$152,656	57.25%
2013	$244,434	$170,322	69.68%
2014	$259,371	$184,921	71.30%
2015	$249,884	$178,157	71.30%
2016	$257,380	$183,502	71.30%

UNDERTAKING NO. JT1.23

WITH REFERENCE TO 4-ENERGY PROBE-32 (E), TO PROVIDE AN UPDATED TABLE 4-5.

Response:

Please see updated Table 4-5 below.

Table JT1.23- 4-Energy Probe-32 (e): Table 4-5

Table 4-5
Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Notes	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	
Opening Balance		$ 14,326,000	$ 13,205,453	$ 15,087,591	$ 14,104,266	$ 15,333,069
Human Resources	1	(324,854)	638,175	655,125	778,468	806,404
Smart Meter Operating Costs	2	(224,975)	224,975	0	0	0
Reallocation of OPA Funded Salaries	3	(193,200)	(154,800)	(6,000)	25,000	(150,000)
Management fees paid in lieu of dividends to parent company		-	1,500,000	(1,500,000)	0	0
Miscellaneous Receivable Write-offs	4	-	74,938	(74,938)	0	0
Software Write-off	5	176,000	(176,000)	0	0	0
TOU implementation	6	57,766	(57,766)	0	0	0
Validation of meter register reads and interval data	7	-	(70,000)	0	0	0
In-House Settlement	8	-	(69,000)	0	0	0
HR Consulting	9	-	0	0	140,000	(140,000)
Property Tax		(432,893)	0	0	0	0
Reclassification of water billing related costs to non-utility expenses		-	0	(487,887)	6,764	(22,411)
Reclassification of intercompany shared services costs to non-utility expenses		-	0	(667,453)	(17,005)	5,006
Reclassification of intercompany shared services revenue to non-utility expenses		-	0	734,198	14,912	(5,505)
Employee future benefit actuarial valuation adjustments		-	0	54,810	48,994	28,575
Software system upgrade		-	0	111,815	(111,815)	0
One time costs related to Cost of Service filing		-	0	0	234,000	(170,700)
Incremental costs associated with monthly billing		-	0	0	0	360,000
Maintenance of overhead Conductors and Devices		-	0	0	0	90,000
Other		(178,391)	(28,384)	197,004	109,485	270,424
Total		13,205,453	15,087,591	14,104,266	15,333,069	16,404,861

Notes:

1 Annual changes in payroll cost expenses (salaries, wages & benefits).

2 An error in the set up of work orders related to Smart Meter operating costs resulted in these costs being classified as construction in progress costs. This error was corrected in 2013 and the smart meter work order costs were correctly classified as operating expenses.

3 Reallocation of payroll costs related to C&DM programs funded via the Ontario Power Authority (OPA).

4 Represents the write-off of older (pre-2013) miscellaneous receivables resulting from the clean up of old accounts deemed uncollectible.

5 Write-off of financial reporting software no longer used.

6 Overtime costs associated with Time of Use implementation.

7 Elimination of third party to validate and cleanse data prior to being sent to MDMR. This was done through the hiring of a new Billing Quality Assurance Coordinator.

8 Reduced expenditures resulting from the development of an in-house settlement model to calculate the weighted average prices. This process was done by a third party service provider prior to this point.

9 Consulting fees related to the review of our compensation system and design. This review was last performed in 2010. In addition the increase in costs relates to the undertaking of an employee cultural survey which will help Guelph Hydro with organizational effectiveness, focusing on what the organization needs to do to ensure that we have the right culture in place to deliver organizational objectives, attract and retain the right employees.

UNDERTAKING NO. JT1.24

WITH REFERENCE TO TABLE 4-ENERGY PROBE-41 (A), TO PROVIDE 2012-2015 ACTUALS.

Response:

Here are revised tables for Table 4-31 (Appendix 2-K) that exclude dollars funded by the OPA and intercompany costs, and related FTE allocations, for 2012 to 2014 actuals, 2015 Bridge Year and 2016 Test Year. Table 4-Energy Probe-41-a should be replaced with the Table below relating to 2016 Test Year.

Table JT1.24-1: Revised Table 4-Energy Probe-41-a

2016 Test Year	TOTAL FTE	Total Compensation
Table 4-31 (Appendix 2-K Employee) Employee Costs	130.83	$ 26,224,932
(a) Minus Guelph Hydro FTE costs allocated to other companies	-4.06	$ (616,021)*
(b) Minus Guelph Hydro FTE costs funded by OPA	-5.00*	$ (650,000)
(c) Minus employee benefit liabilities		$ (10,998,805)
Restated Appendix 2-K minus (a),(b) & (c)	**121.77**	**$ 13,960,106**
(d) Plus other company FTE costs allocated to Guelph Hydro	2.80	$ 656,349
Revenue Requirement	**124.57**	**$ 14,616,455**

Notes:

*** Revised values from Table 4-Energy Probe 41-a.**

2015 Bridge Year	TOTAL FTE	Total Compensation
Table 4-31 (Appendix 2-K Employee) Employee Costs	126.25	$ 24,555,046
(a) Minus Guelph Hydro FTE costs allocated to other companies	-4.06	$ (614,997)
(b) Minus Guelph Hydro FTE costs funded by OPA	-5.25	$ (500,000)
(c) Minus employee benefit liabilities		$ (10,511,759)
Restated Appendix 2-K minus (a),(b) & (c)	**116.94**	**$ 12,928,290**
(d) Plus other company FTE costs allocated to Guelph Hydro	2.80	$ 656,349
Revenue Requirement	**119.74**	**$ 13,584,639**

2014 Actuals	TOTAL FTE	Total Compensation
Table 4-31 (Appendix 2-K Employee) Employee Costs	121.76	$ 22,940,792
(a) Minus Guelph Hydro FTE costs allocated to other companies	-3.48	$ (543,292)
(b) Minus Guelph Hydro FTE costs funded by OPA	-3.27	$ (483,500)
(c) Minus employee benefit liabilities		$ (10,039,368)
Restated Appendix 2-K minus (a),(b) & (c)	**115.01**	**$ 11,874,632**
(d) Plus other company FTE costs allocated to Guelph Hydro	2.55	$ 648,165
Revenue Requirement	**117.56**	**$ 12,522,797**

2013 Actuals	TOTAL FTE	Total Compensation
Table 4-31 (Appendix 2-K Employee) Employee Costs	115.48	$ 20,469,226
(a) Minus Guelph Hydro FTE costs allocated to other companies	-4.92	$ (603,740)
(b) Minus Guelph Hydro FTE costs funded by OPA	-3.85	$ (495,500)
(c) Minus employee benefit liabilities		$ (8,548,844)
Restated Appendix 2-K minus (a),(b) & (c)	**106.71**	**$ 10,821,142**
(d) Plus other company FTE costs allocated to Guelph Hydro	2.55	$ 461,269
Revenue Requirement	**109.26**	**$ 11,282,411**

2012 Actuals	TOTAL FTE	Total Compensation
Table 4-31 (Appendix 2-K Employee) Employee Costs	111.25	$ 19,025,600
(a) Minus Guelph Hydro FTE costs allocated to other companies	-2.75	$ (339,645)
(b) Minus Guelph Hydro FTE costs funded by OPA	-6.52	$ (523,200)
(c) Minus employee benefit liabilities		$ (8,047,612)
Restated Appendix 2-K minus (a),(b) & (c)	**101.98**	**$ 10,115,143**
(d) Plus other company FTE costs allocated to Guelph Hydro	2.65	$ 322,917
Revenue Requirement	**104.63**	**$ 10,438,060**

1

UNDERTAKING NO. JT1.25

WITH REFERENCE TO 4-ENERGY PROBE-42, TO QUANTIFY THE INCREASE IN REVENUE GENERATED FROM WATER BILLING SERVICES.

Response:

An additional $260,000 in revenue from water billing services is anticipated to be generated. This is the result of increased meter reading resulting from the move to monthly billing. The additional revenue will be charged on a cost recovery basis. Both the revenue and the related costs related to the additional meter reading are not reflected in the 2016 budget, since there is no net impact to Guelph Hydro.

UNDERTAKING NO. JT1.26

TO CONFIRM THAT THE CHANGE IN 4-ENERGY PROBE-50 (C) IS INCLUDED IN LINE 5.

Response:

Guelph Hydro confirms that the change in 4-Energy Probe–50(c) is included in Line 5 of the Summary of Proposed Changes tracking form in the Revenue Requirement Workform.

UNDERTAKING NO. JT1.27

TO CLARIFY WHAT WAS MEANT BY THE WORDS "TIME CONSTRAINTS" IN THE INTERROGATORY RESPONSE.

Response:

With respect to 2-Staff-34, the term "time constraints" is referring to situations where an outage or trouble call has occurred and a repair must be carried out to return the system to operation, or to make the situation safe for the public or employees of the company in a timely manner.

Consider the following example scenario which further illustrates the concept:

Guelph Hydro Asset Management staff may not have anticipated the repair of a particular transformer, however the transformer experiences an unforeseen internal fault during the night, causing an outage. A customer reports this outage, initiating a trouble call. Line crews are notified and dispatched to the trouble call and determine that the transformer is not repairable. The transformer is then replaced with a like unit and placed back into service to resolve the outage.

In the above example, a time constraint exists due to failed equipment and an ongoing outage. Professional judgement, experience and the facts as they exist on a case-by-case basis are used to make the repair/replace decision rather than relying on a pre-planned asset management decision to replace the unit. Where Guelph Hydro has the ability to plan repair and replacement work, or the time to fully review repair decisions, it does so using asset management philosophy and procedures, however in cases of time constraints (such as during an outage) it is often impractical to do so. Not all reactive repairs will be made during time constraints, but all time constrained repairs are reactive in nature.

UNDERTAKING NO. JT1.28

TO GO THROUGH THE DEPARTMENTAL BUDGETS AND EXPAND ON WHATEVER CAN BE FOUND.

Response:

An examination of Guelph Hydro's detailed, bottom-up budget for (2015 and) 2016 reveals the following expense items that can be readily correlated to increases in the utility's customer base over the past 2-3 years:

- Increase in fees paid to the Electricity Distributors Association ($25k)
- Community relations customer outreach ($38k)
- Billing, Customer Care and Credit Costs ($140k)

The total OM&A increase for the above-noted items is just about $200,000 over 2012 and 2013 OM&A costs. However, Guelph Hydro submits that not all of the $200,000 increase can be attributed to the increase in the utility's customer base. While a portion of the increase is related to the increase in customers, some of the increase is also due to cost changes beyond Guelph Hydro's control (e.g., the 35% jump in postage rates in 2014), and due to new OEB requirements (e.g., customer engagement).

UNDERTAKING NO. JT1.29

TO CALCULATE THE OM&A PER CUSTOMER, MAY 2014 AND MAY 2015, AND TO INCLUDE WHETHER THAT OM&A PER CUSTOMER FIGURE IS SIGNIFICANTLY LESS THAN THE 6.45 PER CENT THAT IS SEEN IN 4-ENERGY PROBE-38, AND TO GIVE AN EXPLANATION AS TO WHY IT'S SO MUCH LOWER FOR THE FIVE-MONTH PERIOD THAN FOR THE FORECAST 12 MONTH PERIOD.

Response:

Please see the calculated OM&A per customer for May 2014 and May 2015 in the table below. The OM&A per customer at May 2015 is significantly lower than the 6.45% annualized increase as seen in 4-Energy Probe-38, primarily due to timing in the execution and payment of maintenance programs and administrative costs respectively. As illustrated in the table below, which presents the OM&A cost per customer as at July for both 2014 and 2015, the per-customer OM&A is 10.81% higher in 2015 than compared to 2014 for the same period. The timing of OM&A spending is far from linear and there are natural variances in the annual spending cycle.

Note: In order to make the May and July OM&A expenses comparable with the 2014 and 2015 annual numbers as presented in 4-Energy Probe-38, adjustments were made to restate the OM&A expenses from a "budget basis" to a "revenue requirement basis". These adjustments are consistent with the OM&A adjustments provided in response to JT1.1.

Table JT1.29-1: May 2014 & 2015 OM&A per Customer

	2014 May YTD	2015 May YTD	Variance	% Variance
Total OM&A expenses [1]	$ 6,300,053	$ 6,416,867		
Adjustments:				
Reallocate expenses related to water billing services to non-utility expenses	(203,286)	(202,950)		
Reallocate costs associated in providing shared services to affiliate companies	(278,108)	(285,190)		
Remove property taxes	(137,565)	(142,500)		
Utility Solutions costs, SR&ED credit adjustment	(73,708)	(63,630)		
Total Adjusted OM&A expenses	$ 5,607,387	$ 5,722,597	$ 115,210	2.05%
January 1 to May 31 average number of customers	52,235	53,131	896	1.72%
OM&A per Customer	$ 107.35	$ 107.71	$ 0.36	0.33%
Notes				
1. As per response to 4-Energy Probe-36				

Table JT1.29-2: July 2014 & 2015 OM&A per Customer

	2014 July YTD	2015 July YTD	Variance	% Variance
Total OM&A expenses	$ 8,677,889	$ 9,671,381		
Adjustments:				
Reallocate expenses related to water billing services to non-utility expenses	(284,600)	(284,130)		
Reallocate costs associated in providing shared services to affiliate companies	(389,351)	(399,267)		
Remove property taxes	(192,591)	(199,500)		
Utility Solutions costs, SR&ED credit adjustment	(103,191)	(89,082)		
Total Adjusted OM&A expenses	$ 7,708,156	$ 8,699,402	$ 991,247	12.86%
January 1 to July 31 average number of customers	52,335	53,305	970	1.85%
OM&A per Customer	$ 147.28	$ 163.20	$ 15.92	10.81%

UNDERTAKING NO. JT1.30

TO ADVISE WHETHER THE 14 ASSUMED RETIREMENTS CAN GO IN TABLE 4.

Response:

No, the “assumed” in Tables 4-Energy Probe-29-a-2, 4-Energy Probe-29-a-3, 4-Energy Probe-29-a-4, 4-Energy Probe-29-a-5 and 4-Energy Probe-29-a-6, which add up to 14, cannot be put into Table 4-Energy Probe-29-a-1.

Guelph Hydro has explained in Exhibit 4 that it only plans to hire “ahead of retirements”, 1 Meterperson/Apprentice and 1 Lineperson/Apprentice in 2015 and 1 Lineperson/Apprentice in 2016. These tables therefore only focus on the Line Function and Metering, where Guelph Hydro intends to hire ahead of retirements, and also on other trades that could be affected between 2016 and 2020 (System Control, Electrical Maintenance and Vehicle Mechanics). The data in these trade specific tables show reasonable assumptions based on historical trends relating to the numbers of employees assumed to be retiring. In other words, not everyone who is projected to be able to retire based on OMERS eligibility criteria is assumed to be retiring. These trades’ specific tables also show corresponding assumptions on “hiring ahead of retirements”, to be able to maintain a stable, qualified and seasoned workforce and existing levels of customer service.

Taking Table 4-Energy Probe-29-a-2, the line function, as an example, below Guelph Hydro clarifies further what the numbers in these tables are intended to illustrate, which is very different from the data in Table 4-Energy Probe-29-a-1.

Table 4-Energy Probe-29-a-2: Line Function

	“J” qualified at Jan 1		Apprentices at Jan 1			
Year	Management Headcount	Non-Management Headcount	Non-Management Headcount	Total “Line” Headcount	Projected Retirements at Jan 1	Retirements during year
2012	4	21	3	28	2	1 actual
2013	4	19	5	28	1	1 actual
2014	4	19	6	29	1	0 actual
2015	5	21	5	31	1	1 actual
2016	5	21	5	31	2	1 assumed
2017	5	21	5	31	3	2 assumed
2018	5	20	6	31	3	1 assumed
2019	5	20	6	31	2	1 assumed
2020	5	21	5	31	1	0 assumed

2012-2014: This data is based on actual historical data, and except for "retirements during the year", all data is as of January 1 of each year.

2012: Projected retirements, based on OMERS eligibility criteria was 2, and 1 out of the 2 actually did retire. The remaining projected retirement is carried over to 2013 projections. 1 Lineperson/Apprentice was hired in 2012 to replace the retired employee.

2013: Projected retirements, based on OMERS eligibility criteria was 1, and during 2013, this employee did retire. 1 Lineperson/Apprentice was hired in 2013 to replace the retired employee and 1 additional Lineperson/Apprentice was hired in 2013. 1 of the existing management Construction Supervisors was promoted to Operations Manager.

2014: Projected retirements based on OMERS eligibility criteria was 1, and during 2014, since no one in the line function retired, this 1 projected retirement is carried over to 2015 projections. 1 of the existing non-management line department employees is promoted to the management Construction Supervisor position. *In 2014, Guelph Hydro hired its first Lineperson/Apprentice "ahead of retirements", which was expected to be a temporary increase in FTE's for a 2-3 year period, resulting in reaching the Total Headcount of 31 as of January 1, 2015, which includes the temporary 1 FTE increase*. Also reflected in the non-management group is 1 Lineperson off on extended sick leave/LTD and temporarily replaced with a temporary Lineperson/Apprentice.

2015-2016: This data is based on actual historical data to mid-2015, and 2015 and 2016 budget which was based on reasonable estimates of numbers assumed to be retiring, consistent with historical trends, which is lower than projected retirements based on OMERS eligibility criteria.

2015: Projected retirements based on OMERS eligibility criteria was 1, and as of July, 2015, 1 line trade employee has retired, and *has not been replaced since Guelph Hydro pre-hired for this projected retirement in 2014. In 2015, Guelph Hydro hired its second Lineperson/Apprentice "ahead of retirements", as per the planned budget, which again is expected to be a temporary increase in FTE's for a 2-3 year period.* Also reflected in the non-management group is 1 Lineperson off on extended sick leave/LTD and temporarily replaced with a temporary Lineperson/Apprentice.

2016: Projected retirements based on OMERS eligibility is 2. Guelph Hydro is assuming that at least 1 out of the 2 projected retirements will retire in 2016*, and that this assumed retirement will not be replaced in 2016 since Guelph Hydro pre-hired for this projected retirement in 2015.* The 1 remaining 2016 projected retirement is carried to 2017. *In 2016, as per the budget, Guelph Hydro plans to hire its third*

Lineperson/Apprentice "ahead of retirements", which again is expected to be a temporary increase in FTE's for a 2-3 year period.

2017-2020: Data for years 2017-2020, are illustrations demonstrating Guelph Hydro's intent. These tables show scenarios, subject to several assumptions, explained in 4-Energy Probe-29, but which are based on reasonable estimates of assumed retirements, consistent with historical trends, which are lower than projections based on OMERS eligibility criteria of existing employees. The intent is to mitigate risks by planning to hire and build experience ahead of retirements, while remaining responsive to numbers of employees actually retiring, and also ensuring Guelph Hydro maintains a "stable", qualified and seasoned workforce, ready to respond to all types of emergencies and customer needs.

2017: If Guelph Hydro assumes that at least 2 out of the 3 projected retirements will retire in 2017, *then 1 of these 2 assumed retirements will not be replaced in 2017 since Guelph Hydro pre-hired for this projected retirement in 2016,* but that the second would be. The 1 remaining 2017 projected retirement would be carried to 2018. *In this scenario, in 2017, Guelph Hydro expects it will be hiring its fourth Lineperson/Apprentice "ahead of retirements", which again is expected to be a temporary increase in FTE's for a 2-3 year period*.

2018: If Guelph Hydro assumes that at least 1 out of the 3 projected retirements will retire in 2018, *then the 1 assumed retirement is not expected to be replaced in 2018 since in this scenario, Guelph Hydro pre-hired for this projected retirement in 2017.* The 2 remaining 2018 projected retirements are carried to 2019. *In this scenario, in 2018, Guelph Hydro assumes it will be hiring its fifth Lineperson/Apprentice "ahead of retirements", which again is expected to be a temporary increase in FTE's for a 2-3 year period.*

2019: If Guelph Hydro assumes that at least 1 out of the 2 projected retirements will retire in 2019, *then the 1 assumed retirement is not expected to be replaced in 2019 since in this scenario, Guelph Hydro pre-hired for this projected retirement in 2018.* The 1 remaining 2019 projected retirements is carried to 2020. *In this scenario, in 2019, Guelph Hydro assumes it will be hiring its sixth Lineperson/Apprentice "ahead of retirements", which again is expected to be a temporary increase in FTE's for a 2-3 year period.*

2020: If Guelph Hydro assumes no retirements out of the 1 projected retirement in 2020, then the 1 2020 projected retirement is carried to 2021. *Since in this scenario, Guelph Hydro assumed no retirements in 2020, then Guelph Hydro expects to still have* *the 1 Lineperson/Apprentice hired in 2019 "ahead of retirements" and therefore would expect no need in 2020 to hire a seventh Lineperson/Apprentice "ahead of retirements".*

The remaining trade specific tables, 4-Energy Probe 29-a-3, 4-Energy Probe 29-a-4, 4-Energy Probe-a-5 and 4-Energy Probe 29-a-6, were populated using the same methodology used for the Line Function.

Table 4-Energy Probe-29-a-1 is different in all aspects, and cannot be populated using data from the tables below. Unlike the trade specific tables, this table does not demonstrate an in depth analysis of year to year changes, linking projected and actuals/assumed, assuming replacements for assumed retirements and carrying over unrealized retirements from year to year, etc. It simply lists for all management and non-management employees, across all functions, the projected retirements that come up in each year, based on OMERS eligibility criteria, and shows that from 2015 to 2020, there is a total of 31 management and non-management employees who could retire, based on OMERS eligibility criteria.

UNDERTAKING NO. JT1.31

TO CONFIRM THE 167,870 FIGURE FOR 2015 BUDGET INCREASE, AS STATED IN 4-STAFF-50, UNDER (A).

Response:

On the original response to 4-Staff-50 Guelph Hydro made the following comments:

"The 2015 decrease in Bridge year expenditures compared to 2014 is the result of a budgeting error. Costs for activity related to MV90 licensing/maintenance as well as meter technician time spent on billing/customer service field activities (e.g., turn-ons, turn-offs, high-bill complaints, power quality investigations, etc.) was inadvertently omitted from the 2015 budget (i.e., the 2015 budget amount for Billing and Collecting of $2,021,744, should have been higher by $167,870)."

The correct response should have been as follows:

"The 2015 decrease in Bridge year expenditures compared to 2014 is the result of a budgeting error. Costs for activity related to MV90 licensing/maintenance as well as meter technician time spent on billing/customer service field activities (e.g., turn-ons, turn-offs, high-bill complaints, power quality investigations, etc.) was inadvertently omitted from the 2015 budget (i.e., the 2015 budget amount for Billing and Collecting of $2,021,744, should be higher by $165,000)."

UNDERTAKING NO. JT1.32

TO PROVIDE THE BREAKDOWN IN 4-VECC-38C FOR 2012 TO 2015.

Response:

The following table provides the breakdown requested in 4-VECC-38C for the years 2012 to 2015.

Table JT1.32: Updated Table 4-VECC-38-c: 2012-2015 Annual Manual Reads

		2012		2013		2014		2015	
Customer	Billing Frequency	Electric Manual Reads	Water Manual Reads	Electric Manual Reads	Water Manual Reads	Electric Manual Reads	Water Manual Reads	Electric Manual Reads	Water Manual Reads
Residential	bi-monthly	2,364	224,898	396	228,882	324	230,910	120	233,226
Commercial	monthly	42,132	29,796	27,588	29,340	25,512	29,472	18,132	30,012
MUSH	monthly	1,968	-	1,968	-	1,968	-	1,968	-
Generation	monthly	1,980	1,980	2,520	2,520	2,832	2,832	3,000	3,000
Total		**48,444**	**256,674**	**32,472**	**260,742**	**30,636**	**263,214**	**23,220**	**266,238**

UNDERTAKING NO. JT1.33

TO DESCRIBE THE COSTS OF INCREMENTAL SERVICES.

Response:

The sum total of Guelph Hydro's pre-filed evidence and relevant interrogatory responses provide full and complete evidence of the value that ratepayers will receive for the $16.4 million in OM&A costs that Guelph Hydro forecasts to incur to serve these customers in 2016. Some of the costs are driven by a number of key initiatives and/or regulatory requirements that underpin a significant portion of its OM&A increase. These initiatives and the associated costs are shown in the table below.

This list is non-exhaustive, but rather is a succinct listing of costs which represents incremental value-added initiatives that will benefit ratepayers, and in some cases reflect initiatives (and their associated costs) that were supported or requested by ratepayers during Guelph Hydro's customer engagement in the lead-up to filing this rates application.

Table JT1.33: Description of Costs of Incremental Services

Incremental Services	Improved Outcome	Incremental Cost		
Control Room 24/7	Compliance with regulatory grid and safety response requirements. More timely response to after-hours customer calls and outages. Large customers noted to GHESI during GHESI's customer engagement session that they require a live person to interact 24/7	$245,780	2 FTEs	1 System Control Room Supervisor; 1 System Control Room Operator
Monthly Billing - Incremental Cost	• More timely bills for residential customers • More effective customer response to energy cost drivers • Improve customer anticipation and management of payments • Better response to pricing signals (using electricity at times of the day when prices are lower) • More frequent communication with customers	$360,000		Issuance, reminder notices, EBT transactions and collection costs (please see the response to 4-Energy Probe-34)
MyEnergyView portal - website enhancement	Customers can manage their TOU data; E-billing, improved online preauthorized services	$25,000		Service provider cost
Class A Global Adjustment - manual settlement process	13 large customers benefit from a lower Global Adjustment charge if they manage their peak demand	$900		combined internal Billing, Customer Service, and Regulatory Affairs departments cost
Internal wholesale settlement	Customers benefit from more accurate weighted average market prices	$17,500		combined internal Billing, Customer Service, and Regulatory Affairs departments cost
Wholesale settlement software	Customers benefit from more accurate weighted average market prices	$9,000		Software provider incremental on-going cost
Net-Metering - billing set-up and settlement	Customers benefit from Net-Metering program	$5,000		combined internal Billing, Customer Service, engineering, and Regulatory Affairs departments cost
Billing Accuracy enhancement - Billing Quality Coordinator	Customers benefit from more accurate billing	$90,387	1 FTE	1 Billing Quality Assurance Coordinator
Expand SCADA system	Enable renewable generation; expanded monitoring and net-metering projects	$105,309	1 FTE	1 SCADA Technologist
Expand customer communication methods- online chat, social media (tweets, notifications, etc.)	Improved customer communication; Enhanced Customer Engagement and Communication	$129,317	1 FTE	1 Communications Specialist
Implement Ontario Energy Support Program (OESP) for low income customers	Offer financial support to low-income customers	$8,000		combined internal Billing, Customer Service, Credit, and Regulatory Affairs departments cost
LEAP incremental cost	Offer financial support to low-income customers	$10,000		Based on the increase of the revenue requirement, LEAP amount increased from $31,000 to $41,000
Implement Interactive Voice Recognition (IVR)	Improved customer service	$10,330		Service provider cost
Embedded renewable generation	More than 300 customers benefit from the microFIT and FIT programs, however there are increased costs to administer this program	$85,771	1 FTE	1 Smart Grid Technician
Ontario One Call	Customers benefit from timely locate requests and the risk of damaging underground powerlines is reduced	$15,000		
	Total	**$ 1,117,294**		

UNDERTAKING NO. JT1.34

BASED ON ANY FURTHER UPDATES OR CORRECTIONS OR OTHER CHANGES MADE AS A RESULT OF THE TECHNICAL CONFERENCE QUESTIONS, TO PROVIDE AN UPDATE TO THE RESPONSE TO THIS QUESTION, INCLUDING AN UPDATED REVENUE REQUIREMENT WORK FORM IN ELECTRONIC FORM.

Response:

Reference: 6-Energy Probe-56

Guelph Hydro has updated Table 6-1 through 6-4 to reflect all changes tracked in the RRWF, Tab.10. Tracking Sheet.

In addition, Guelph Hydro has updated Appendix 6-A of the Application and provided the RRWF in electronic form (please see Guelph_TC_Undertakings_JT1_34_Updated_Rev_Reqt_Workform_20150821 file).

Table JT1.34-1-Table 6-Energy Probe-56-1: Table 6-1 Determination of Net Utility Income

Line No.	Particulars		Initial Application
	Operating Revenues:		
1	Distribution Revenue (at Proposed Rates)		$31,114,725
2	Other Revenue	(1)	$2,307,201
3	Total Operating Revenues		$33,421,926
	Operating Expenses:		
4	OM+A Expenses		$16,404,861
5	Depreciation/Amortization		$5,751,746
6	Property taxes		$335,074
7	Capital taxes		$ -
8	Other expense		$ -
9	Subtotal (lines 4 to 8)		$22,491,681
10	Deemed Interest Expense		$4,523,893
11	Total Expenses (lines 9 to 10)		$27,015,574
12	**Utility income before income taxes**		$6,406,352
13	Income taxes (grossed-up)		$768,558
14	**Utility net income**		$5,637,794

Table JT1.34-2-Table 6-Energy Probe-56-2: Table 6-2 Rate Base:

Rate Base

Line No.	Particulars		Initial Application
1	Gross Fixed Assets (average)	(3)	$169,516,735
2	Accumulated Depreciation (average)	(3)	($35,685,907)
3	Net Fixed Assets (average)	(3)	$133,830,828
4	Allowance for Working Capital	(1)	$17,722,775
5	**Total Rate Base**		$151,553,603

Allowance for Working Capital - Derivation

Controllable Expenses		$16,533,587
Cost of Power		$219,770,081
Working Capital Base		$236,303,668
Working Capital Rate %	(2)	7.50%
Working Capital Allowance		$17,722,775

Table JT1.34-3-Table 6-Energy Probe-56-3: Table 6-3 Return on Rate Base

Description	2015 Bridge Actual	2016 Test Existing Rates	2016 Test - Required Revenue
Actual Return on Rate Base:			
Rate Base	$159,681,877	$151,553,603	$151,553,603
	$0	$0	$0
Interest Expense	$4,836,445	$4,523,893	$4,523,893
Net Income	$3,982,685	$3,368,551	$5,637,794
Total Actual Return on Rate Base	**$8,819,130**	**$7,892,444**	**$10,161,687**
Actual Return on Rate Base	5.52%	5.21%	6.71%
Required Return on Rate Base:			
Rate Base	$159,681,877	$151,553,603	$151,553,603
Return Rates:			
Return on Debt (Weighted)	5.05%	4.98%	4.98%
Return on Equity	9.42%	9.30%	9.30%
Deemed Interest Expense	$4,836,445	$4,523,893	$4,523,893
Return On Equity	$6,016,813	$5,637,794	$5,637,794
Total Return	**$10,853,258**	**$10,161,687**	**$10,161,687**
Expected Return on Rate Base	6.80%	6.71%	6.71%

Table JT1.34-4-Table 6-Energy Probe-56-4: Table 6-4 Revenue Deficiency Determination

		Initial Application	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		$3,087,405
2	Distribution Revenue	$28,027,320	$28,027,320
3	Other Operating Revenue Offsets - net	$2,307,201	$2,307,201
4	**Total Revenue**	$30,334,520	$33,421,926
5	Operating Expenses	$22,491,681	$22,491,681
6	Deemed Interest Expense	$4,523,893	$4,523,893
8	**Total Cost and Expenses**	$27,015,574	$27,015,574
9	**Utility Income Before Income Taxes**	$3,318,947	$6,406,352
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,883,492)	($2,883,492)
11	**Taxable Income**	$435,455	$3,522,860
12	Income Tax Rate	26.50%	26.50%
13	**Income Tax on Taxable Income**	$115,396	$933,558
14	**Income Tax Credits**	($165,000)	($165,000)
15	**Utility Net Income**	$3,368,551	$5,637,794
16	**Utility Rate Base**	$151,553,603	$151,553,603
17	Deemed Equity Portion of Rate Base	$60,621,441	$60,621,441
18	Income/(Equity Portion of Rate Base)	5.56%	9.30%
19	Target Return - Equity on Rate Base	9.30%	9.30%
20	Deficiency/Sufficiency in Return on Equity	-3.74%	0.00%
21	Indicated Rate of Return	5.21%	6.71%
22	Requested Rate of Return on Rate Base	6.71%	6.71%
23	Deficiency/Sufficiency in Rate of Return	-1.50%	0.00%
24	Target Return on Equity	$5,637,794	$5,637,794
25	Revenue Deficiency/(Sufficiency)	$2,269,243	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,087,405 **(1)**	

UNDERTAKING NO. JT1.35

IF NECESSARY, TO PROVIDE AN UPDATE TO TABLE 7-ENERGY PROBE-58 (B) TO REFLECT ANY CHANGES IN THE REVENUE DEFICIENCY AS A RESULT OF THE UPDATES, CORRECTIONS, OR CHANGES TO THE APPLICATION AS A RESULT OF THE RESPONSES TO THE TECHNICAL CONFERENCE QUESTIONS.

Response:

At the time of the undertaking response preparation, Guelph Hydro noticed a misinterpretation of the meter reading cost allocation in its Cost Allocation model, Tab I7.2 Meter Reading. According to the model Instructions (please see tab Instructions),

"The purpose of this input worksheet is to derive the weighting factors for the allocator CWMR, which is used only to allocate costs that are recorded in account 5310 Meter Reading Expense. […] This worksheet has not been modified to reflect automated meter reading. The Rows in worksheet I7.2 continue to reflect differences in customer density, relative difficulty in reaching the meter, and frequency of reading the meter in the respective classes. […] Note that the cost of the Smart Meter Entity is treated as a pass-through cost with its own rate rider. It is not included in the service revenue requirement and is not allocated in this model, except as a component of Working Capital (account 4751)."

Since the Residential and General Service below 50 kW have smart meters installed, it is Guelph Hydro's interpretation that the meter reading costs recorded in account 5310 Meter Reading Expenses should not be allocated to these two classes. In addition, Guelph Hydro has not budgeted any third party meter reading costs for Residential and GS< 50 kW in 5310 account for 2016 Test Year; therefore, Guelph Hydro corrected its Cost Allocation model to reflect zero meter reading cost allocation (please see Tab I7.2 – Meter Reading, cells D28 and G28, and Tab O4-Summary by Class & Accounts, cells E167 and F167). There is no change in revenue deficiency as the effect of Cost Allocation model correction. Guelph Hydro filed its updated Cost Allocation model in Excel version (please see Guelph_TC_Undertakings_JT1_35_Updated_CA_Detailed_RUN1_20150821 file).

Guelph Hydro has updated Table 7-Energy Probe-58-b) to reflect all changes in the revenue deficiency as a result of the updates following the technical conference questions and the correction to its Cost Allocation model, and presented the table below.

Table JT1.35 -Table 7-EP-58-b): Table 7-8: 2016 Cost Allocation Results and the Proposed Revenue-to-Cost Ratios

Rate Class	2016 Cost Allocation results	Proposed Adjustment to Revenue-to-Cost Allocation ratios	2016 Proposed Revenue-to-Cost Ratios	Target range
Residential	89.57%	3.56%	93.13%	85 - 115
General Service Less Than 50 kW	116.11%	0.00%	116.11%	80 - 120
General Service 50 to 999 kW	109.81%	0.00%	109.81%	80 - 120
General Service 1000 to 4999 kW	143.80%	-23.80%	120.00%	80 - 120
Large Use	86.05%	7.08%	93.13%	85 - 115
Street Lighting	97.58%	0.00%	97.58%	80 - 120
Unmetered Scattered Load	152.83%	-32.83%	120.00%	80 - 120
Sentinel Lighting	108.25%	0.00%	108.25%	80 - 120

<u>UNDERTAKING NO. JT1.36:</u> Number skipped. Being used to file Board Staff's July 6, 2015 presentation - Rate Design – Commercial / Industrial Stakeholder Consultation

Guelph Hydro received from Board Staff the July 6, 2015 presentation titled "Rate Design – Commercial / Industrial Stakeholder Consultation" which is referenced at 8-Staff-61 response of the evidentiary record and mentioned in the Technical Conference Transcript at page 198 to 199. Guelph Hydro has attached the presentation in response to this undertaking (please see Appendix JT1.36: Board Staff's July 6, 2015 presentation - Rate Design – Commercial / Industrial Stakeholder Consultation).

UNDERTAKING NO. JT1.37

TO PROVIDE WHATEVER BUSINESS CASE CAN BE PROVIDED WITH RESPECT TO THE ZIGBEE CHIP.

Response:

Guelph Hydro has provided a business case with respect to the Zigbee chip in Appendix JT1.37.

In its Decision and Rate Order dated February 22, 2012 resulting from Guelph Hydro's 2012 CoS proceedings (EB-2011-0123), the Board did not approve the recovery of the cost of the Zigbee chip in rates. Instead, the Board directed Guelph Hydro to record the amounts associated with the Zigbee technology in a sub-account of Account 1555, to be called "Sub-account – Zigbee Chip Initiative". The Board stated that if, at a future point in time, Guelph Hydro determined that there was the potential for the Zigbee chip to provide any ratepayer benefit, Guelph had the option of requesting a prudence review to seek the recovery of its Zigbee chip investment on the basis that it acted prudently in making its investment in the Zigbee chip.

In the current proceeding (EB-2015-0073), Guelph Hydro is requesting for approval to include the 1555 – Smart Meter Capital –Sub-account Zigbee Chip initiative balance of $55,653 (Net Book Value) in the 2016 rate base.

The attached business case is being filed in response to this undertaking and demonstrates that management's decision to invest in the Zigbee chip was prudent. As explained in the attached business case, the Zigbee chip is now used and useful, providing direct benefits to ratepayers. The Zigbee chip continues to act as a low cost enabler for future conservation and demand management initiatives and other smart grid developments.

Appendix JT1.3: UtilityPULSE Letter

UtilityPULSE

Feedback that inspires action

August 11, 2015

Sandy Manners
Director Corp Communications
Guelph Holdings Inc.
395 Southgate Drive
Guelph, ON N1G4Y1

Dear Sandy:

Re: **UtilityPULSE questions from:**
FILE NO.: EB-2015-0073Guelph Hydro Electric Systems Inc.
VOLUME: Technical Conference
DATE: August 10, 2015

1- **LDC comparison data and names of 2013 participating LDCs**

I will answer this question in two parts.
Part A: Ontario Benchmark

The Ontario Benchmark numbers that appear in the 2013 survey are generated via interviews with residential and small commercial customers throughout the Province of Ontario. As such, every LDC is represented in the Ontario Benchmark.

Part B: Names of client LDCs in the 2013 survey: UtilityPULSE database

Data from the 2013 client LDCs (25 Ontario LDCs) appears in the numbers when we reference the UtilityPULSE database.

As per earlier correspondence (email July 8, 2015) the UtilityPULSE database comprised of interview findings from the 25 LDCs, covers 50.2% of the Residential & Small Commercial customers in Ontario (using OEB 2012 data). The Ontario benchmark is based on interviewing customers throughout Ontario covering 100% of Ontarians.

It is unfortunate that Mr. Shephard is preparing to file a motion to reveal the names of the 25, 2013 client LDCs. The reality is we do not have permission from the LDCs to reveal their names.

In addition, UtilityPULSE exists in a very competitive industry – more so with the inclusion of customer satisfaction in the scorecard. Publishing our client list would represent a competitive risk.

2- **Proprietary calculations**

In earlier correspondence (Monday July 13, 2015) we provided comprehensive background on both the Customer Experience Performance rating (CEPr) and Customer Engagement Index (CEI) . Our earlier correspondence provided full details i.e., the four central questions of CEPr and the seven dimensions of the CEI, as to what is included in each of the calculations. We respectfully request a complete rationale for requesting the proprietary calculations for both of these items and how knowing the calculations would affect decisions.

As we understand it providing the information in confidence restricts the information from going public but it allows every intervenor to access or use the information – which could have adverse consequences to UtilityPULSE.

In 2013 we (UtilityPULSE) had a 15 year history of serving the LDC industry, we now have 17 years of history. We do not know of any survey company that has as much history with Ontario LDCs as we do. As you know, UtilityPULSE is totally focused on the LDC industry, unlike many competitors who serve multiple industries. To our knowledge we are the only company that generates the Ontario benchmark by conducting interviews throughout Ontario. By design we do not call the composite average of participating LDCs as the benchmark, we do call this information the UtilityPULSE database. As such our data and insights come from extensive customer research in the industry and experience – we believe that Ontario LDCs and their customers benefit.

I trust the above addresses the concerns raised at the Technical Conference.

Sincerely,

Sid Ridgley
Utility*PULSE*
The survey division of Simul Corporation
Tel: +1 905 895 7900
Email: sidridgley@utilitypulse.com

Appendix JT1.17: 2011 and 2012 Asset Condition Assessments

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Distribution Asset Condition Assessment

Kinectrics Report: K-418059-RC-001-R2

May 12th, 2011

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue, Unit 2, Toronto, Ontario, Canada M8Z 6C4

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Guelph Hydro Electric Systems Inc.

GUELPH HYDRO ELECTRIC SYSTEMS INC.
Distribution Asset Condition Assessment

Kinectrics Report: K-418059-RC-001-R2

May 12th, 2011

Prepared by:

Leslie Greey
Engineer/Scientist
Distribution and Asset Management Department

Reviewed by:

Katrina Lotho
Engineer/Scientist
Distribution and Asset Management Department

Approved by:

Yury Tsimberg
Director – Asset Management
Transmission and Distribution Technologies

REGISTERED PROFESSIONAL ENGINEER
Y. TSIMBERG
PROVINCE OF ONTARIO

Dated: May 12, 2011

Revision History

Revision Number	Date	Comments	Approved
R0	April 15, 2011	Initial Draft	N/A
R1	May 9, 2011	Revised Draft	N/A
R2	May 12, 2011	Final Report	Y. Tsimberg

EXECUTIVE SUMMARY

Guelph Hydro Electric Systems Inc. (GHESI) retained Kinectrics Inc. (Kinectrics) to carry out an Asset Condition Assessment (ACA) of GHESI's key distribution assets. The assets were divided into several Asset Groups. For each of these Asset Groups, the ACA included the following tasks:

- Derive Health Indexes
- Provide Capital Replacement Plan
- Provide recommendations for prioritized data gap closure

This report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

Information Availability and Health Index Methodology

The general methodology for Asset Condition Assessment is described, while each Asset Group is presented in detail in its own section. The information for each Asset Group includes the Health Index (HI) formula, HI distribution and recommendations for closing data gaps in a prioritized manner as well as optimal and levelized Capital Replacement Plan. Where appropriate, the results were modified based on the expert opinion of GHESI staff.

Health Index Results Summary

For nine Distribution Asset Categories there was sufficient asset information to calculate Health Indexes. Table ES - 1 shows, for each of the nine Distribution Asset Categories, the total number of assets, sample size, and Health Index distribution. Detailed results for each Distribution Asset Category are shown in Section C RESULTS AND FINDINGS.

Table ES - 1 Health Index Results Summary

Distribution Asset Category		Number of Units			Health Index Distribution				
		Population	Sample	Percentage	Very Poor	Poor	Fair	Good	Very Good
1	Power Transformers	2	2	100%	0	0	1	0	1
					0%	*0%*	*50%*	*0%*	*50%*
2	Pole Top Transformers	1799	1789	99%	9	48	305	412	1015
					1%	*3%*	*17%*	*23%*	*57%*
3	Pad Mounted Transformers	3623	3623	100%	6	13	305	625	2672
					0%	*0%*	*8%*	*17%*	*74%*
4	Submersible Transformers	41	39	95%	1	4	1	6	27
					3%	*10%*	*3%*	*15%*	*69%*
5	Vault Transformers	82	82	100%	1	1	5	27	48
					1%	*1%*	*6%*	*33%*	*59%*
6	Overhead Switches	237	237	100%	0	0	17	91	129
					0%	*0%*	*7%*	*38%*	*54%*
7	Pad Mounted Switchgear	62	61	98%	0	0	25	19	17
					0%	*0%*	*41%*	*31%*	*28%*
8	Wood Poles	7888	7864	99%	1115	1047	1901	2155	1646
					14%	*13%*	*24%*	*27%*	*21%*
9	Concrete Poles	676	676	100%	65	45	193	345	28
					10%	*7%*	*29%*	*51%*	*4%*

Capital Replacement Plan

The Capital Replacement Plan (CRP) includes two aspects: the number of units that are planned to be replaced and the corresponding replacement cost.

The number of units to be replaced was estimated based on asset condition and its probability of failure, using either a proactive approach or reactive approach. In the proactive approach assets are planned to be replaced before failure, whereas in the reactive approach assets are replaced on failure. Table ES - 2 summarizes the assumed replacement cost, replacement plan approach, and resultant capital replacement plan in the first year. Of the nine Distribution Asset Categories assessed, replacement costs were given for eight of them (excluding vault transformers).

Table ES - 2 Capital Replacement Plan Summary

Distribution Asset Category		Assumed Replacement Cost	Replacement Approach	Units to Replace		Capital Replacement Cost	
				Optimal	*Levelized*	Optimal	*Levelized*
1	Power Transformers	$500,000	Reactive	0	*0*	$0	*$0*
2	Pole Top Transformers	$5,300	Reactive	16	*16*	$84,800	*$84,800*
3	Pad Mounted Transformers	$31,000	Proactive	6	*2*	$186,000	*$62,000*
4	Submersible Transformers	$10,000	Reactive	1	*1*	$10,000	*$10,000*
6	Overhead Switches	$20,000	Reactive	0	*0*	$0	*$0*
7	Pad Mounted Switchgear	$26,500	Reactive	0	*0*	$0	*$0*
8	Wood Poles	$7,000	Proactive	1118	*224*	$7,826,000	*$1,568,000*
9	Concrete Poles	$10,000	Proactive	65	*13*	$650,000	*$130,000*

The scheduling of capital expenditure for assets which are replaced **proactively** has been levelized so replacement is done over a period of time (up to five years) after the optimal replacement year. Those assets which are replaced **reactively** also have a levelized schedule so replacement is done over a period of time (up to five years) before the optimal replacement year. This methodology is to ensure that run to failure assets are replaced before they fail.

The Overall Optimal Capital Replacement Plan is the total optimal replacement projections for all the assets over the next thirty (30) years in 2011 dollars. This is shown on Figure ES - 1.

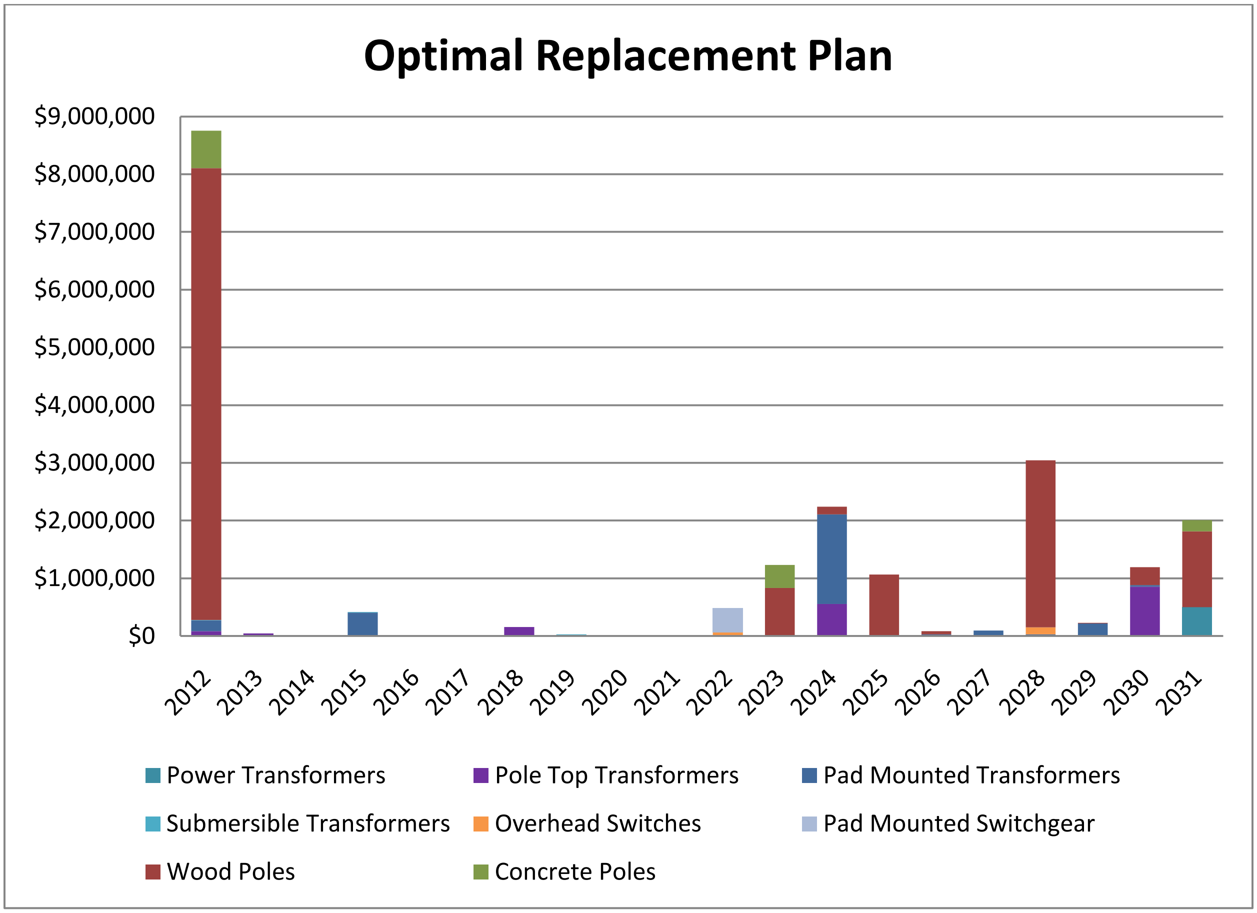


Figure ES - 1 Optimal Capital Replacement Plan

The Overall Levelized Capital Replacement Plan is the total levelized replacement projections for all the assets over the next thirty (30) years in 2011 dollars. The Levelized approach allows for assets which are replaced **proactively** to be replaced up to five years **after** their calculated end of life and for assets which are replaced **reactively** replaced to be replaced up to five years **before** their end of life (making it a proactive replacement). This is shown on Figure ES - 2.

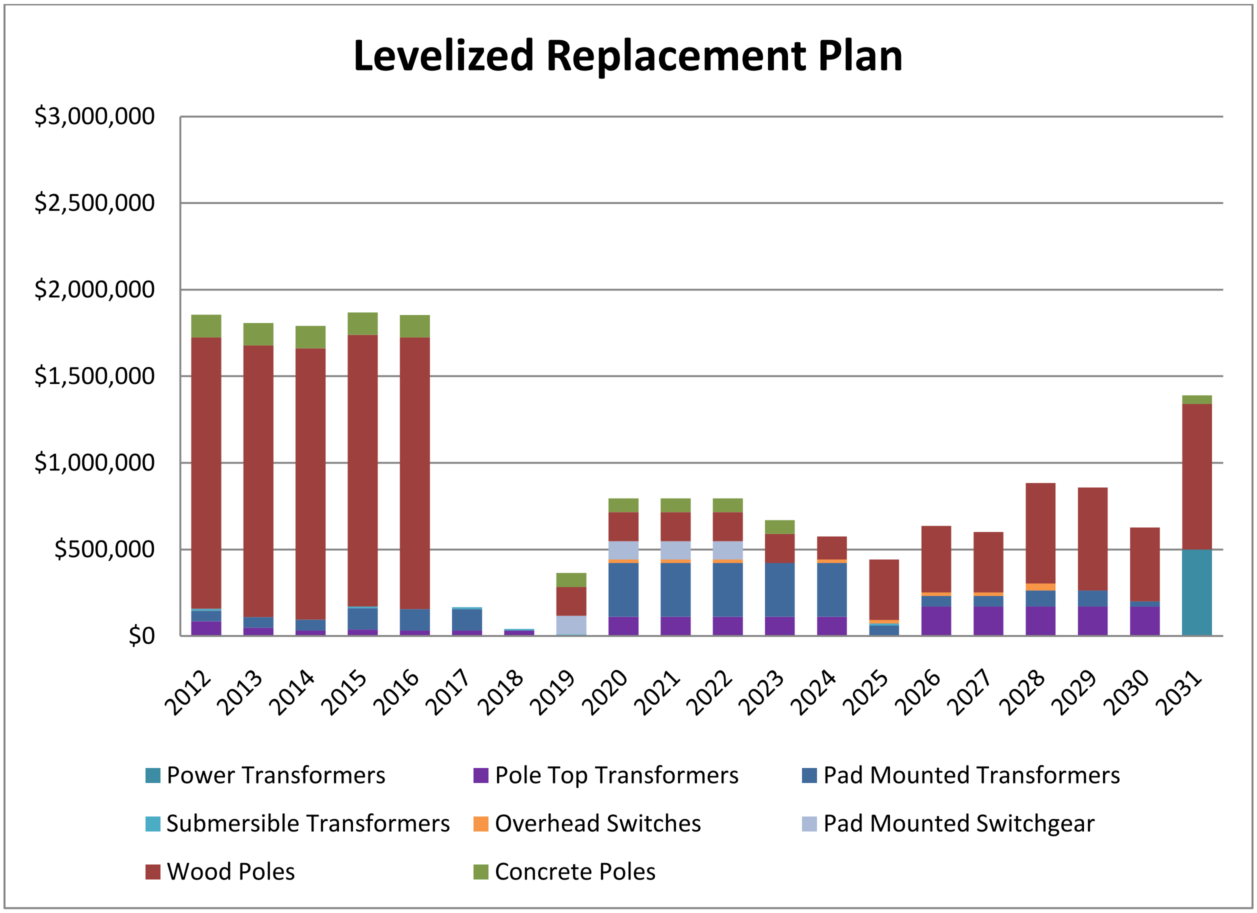


Figure ES - 2 Levelized Capital Replacement Plan

Conclusions and Recommendations

1. There were no data gaps for *Wood Poles* and *Concrete Poles*. Kinectrics recommends continuing to collect Data for those Assets.

2. There was also sufficient data for *Power Transformers,* including Oil Testing and Oil Quality Inspections done on a regular basis to properly assess their condition. Kinectrics recommends continuing to collect Data for those Assets.

3. There was generally sufficient condition data available for *Pole Top Transformers*, *Pad Mounted Transformers, Submersible Transformers*, and *Vault Transformers*. Kinectrics recommends continuing to gather and record applicable data for those assets. In future asset condition assessments monthly loading should replace peak loading if it is available.

4. *Vault Transformers* require replacement costs to be included in the Capital Replacement Plan. Kinectrics recommends developing a replacement plan that includes Vault Transformers based on condition based assessments.

5. There was some data provided for *Overhead Switches* and *Pad Mounted Transformers*, such as age, operating practices (i.e., customers), peak loading and/or maintenance history. Kinectrics recommends gathering and recording detailed inspection data in order to derive a more accurate health index distribution, effective age and capital replacement plan.

6. There was not sufficient data available for *Vaults* (Underground Distribution, Building and Manholes), *Underground Cables* and *Submersible Switchgear*. Kinectrics recommends that applicable inspection, fault history and maintenance information be gathered and recorded for these assets. They should be included in future asset condition assessments and condition-based capital plans.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

A INTRODUCTION

THIS PAGE HAS BEEN INTENTIONALLY LEFT BLANK

1 BACKGROUND

Guelph Hydro Electric Systems Inc. (GHESI) supplies electricity to homes and businesses and is regulated by the Ontario Energy Board (OEB).

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and components and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

GHESI retained the services of Kinectrics to carry out condition assessment of its electrical distribution system assets.

A considerable portion of this work was devoted to the development of Health Indices based on the information provided by GHESI and the expert opinion of GHESI staff.

This report presents the findings of the GHESI's distribution assets condition assessment and includes the development of Health Indices for the specified Distribution Asset Categories.

2 OBJECTIVES

Kinectrics performed an Asset Condition Assessment of GHESI's electrical distribution system. The following distribution system assets, referred to as Distribution Asset Categories throughout this report, were covered under the scope of work for this project:

1 Power Transformers
2 Pole-Top Transformers
3 Pad-Mounted Transformers
4 Submersible Transformers
5 Vault Transformers*
6 Overhead Switches
7 Pad Mounted Switchgear
8 Wood Poles
9 Concrete Poles

** Not included in Capital Replacement Plan*

Recommendations for future data collection and future Health Index Formulations were included for all Assets. However, of the nine distribution asset categories, sufficient data for Capital Replacement was only provided for eight. Vault Transformers are not included in the Capital Replacement Plan.

3 SCOPE OF WORK

The project includes the following:

1. Provide Recommended Health Index formulations used to derive Health Indices
2. Calculate and provide Health Index distribution for each of the aforementioned asset categories
3. Provide Capital Replacement Plan
4. Identify condition data gaps and provide recommendations for their prioritized closure

These areas and the factors of assessments covered under this project, are based on Kinectrics experience and familiarity with the industry requirements, and provides rational for the capital replacement expenditures being sought by GHESI. As such, the results will help GHESI in its service rate application submission to the OEB and will provide a basis for a medium to long-term capital plan for its distribution assets. However, replacement requirement due to poor asset condition is not the only basis for developing a capital plan. Other factors, such as obsolescence, design flaws, exposure to severe environmental conditions, system requirements, etc. should also be taken into account when developing such plan.

4 DELIVERABLES

The deliverables in this report include the following information:

- Short description of the asset groups being considered in the study
- Discussion of asset degradation and end-of-life issues
- Health Index results for the Asset Groups
- Description of methodology for assessment of asset replacements
- Capital replacement plan
- Data Gap Closure

B ASSET CONDITION ASSESSMENT METHODOLOGY

THIS PAGE IS INTENTIONALLY LEFT BLANK

1 HEALTH INDEXING

Health Indexing quantifies equipment condition based on numerous condition criteria that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index (HI) 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 differs from maintenance testing, 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 that are used to derive the Health Index. In formulating a Health Index, condition parameters are ranked and evaluated, through the assignment of corresponding weights, based on their contribution to asset degradation. The condition parameter score is an evaluation of an asset with respect to a condition parameter.

A condition parameter may also be comprised of several sub-condition parameters. For example, a parameter called "insulation" for power transformers may be a composite of Oil Quality and Oil DGA.

The Health Index, which is a function of the condition parameter scores and weightings, is therefore given by:

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

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)}$$

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)

While weightings are assigned based on the priority level of condition parameters, scores represent the evaluation of an asset against condition criteria. A condition criterion is the scale that is used to determine an asset's score for a particular parameter.

Consider, for example, a system where the Health Index is described under one of the following five categories: very poor, poor, fair, good, and very good. A scoring system of 0 through 4 corresponds to the "very poor" through "very good" categorization. Consider a parameter "age" for which this scoring system is applied. The condition criteria will define the age that constitutes scores of 0 through 4 (i.e. a pole mounted transformer that is 50 years old will receive a score of 0; whereas one that is 2 years old will receive the maximum score of 4). Note that in this study, the condition criteria scoring system consist of values from zero (0) through four (4), with 0 being the worst and 4 being the best score.

De-rating factors are also used to adjust a calculated Health Index to reflect certain conditions. These may be factors that may or may not be related to asset condition, but contribute to the asset's risk of failure. For example, if a particular type of Wood Pole, such as Douglas Fir, is prone to problems. Dominant parameters may be used as de-rating factors. These are asset properties that are considered to be of such importance that its status has a dominant impact on the value of the Health Index. De-rating factors are used to reduce the Health Index of an asset by a certain percentage. If a calculated Health Index is, say, 90%, a de-rating factor of 80% will reduce the effective Health Index to 90% x 80% = 72%.

2 EFFECTIVE AGE

Once the Health Index of an asset is determined, its *effective age* can be evaluated by establishing a relationship between its Health Index and its probability of failure. Effective age is different from chronological age in that it is based on the asset's condition and the stress stresses applied to the asset.

2.1 Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. The failure rate equation is in the form of:

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

where

f = failure rate of an asset (frequency or the number of expected failures per year) at time t
t = time
α, β = constant parameters that control the rise of the curve

The corresponding probability of failure is given as:

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

where

P_f = probability of failure
f = failure rate of an asset
α, β = constant parameters that control the rise of the curve

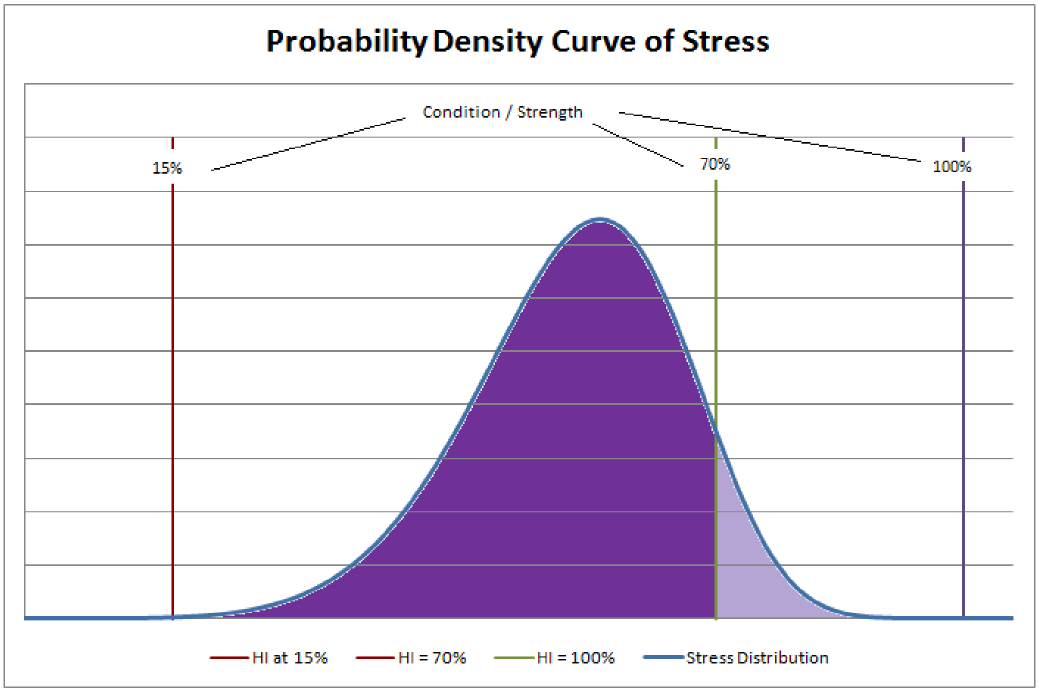
Different assets groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used control the location and steepness of the exponential rise of these curves. For each asset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

2.2 Quantitative Relationship between Health Index and Probability of Failure

Failure of an asset occurs when the stress that an asset experiences exceeds is strength. Assuming that stress is not constant and the stress probability is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure.

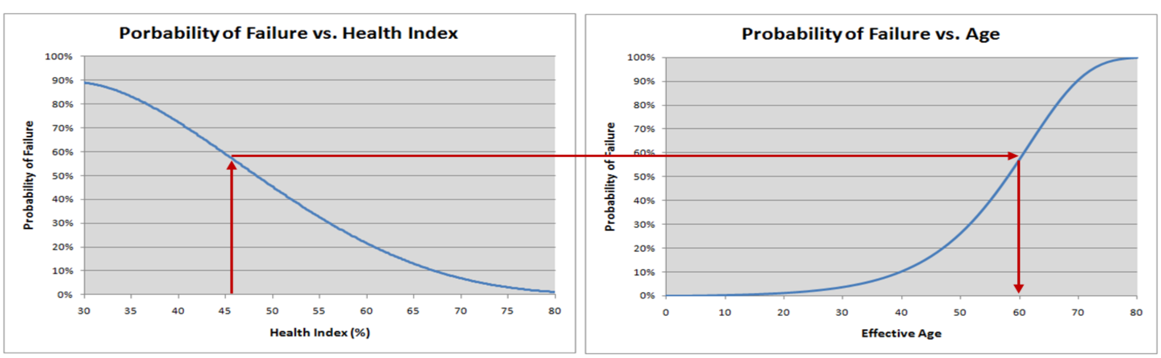
Consider the Health Index to be a representation of condition. Two Health Index points and the probabilities of failure at those Health Index points can be used to find the probabilities of failure at other Health Index values. This is illustrated in the figure below. The vertical line represents condition (Health Index) and the area under the curve to the right of the line represents the probability of failure.

A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 15% at its end of life. Moving the vertical line left from 100% to 15%, the probabilities of failure at other Health Indices can be found.



2.3 Effective Age and Remaining Life

The effective age associated with a particular Health Index is found by first plotting the Probability of Failure vs. Health Index curve. This is the area under the probability density curve between the 100% and 30% Health Index points. This curve is shown on the left hand graph of the figure below. The associated probability of failure is then found on Probability of Failure vs. Age graph (right hand graph). The effective age is read from the horizontal axis of the right hand graph.



Relationship between Health Index and Effective Age

The remaining life can be estimated as the difference between the asset's maximum life expectancy and its effective age. For example, a pole mounted transformer that has an effective age of 35 years will have a remaining life of 45-35 = 10 years.

3 CAPITAL REPLACEMENT PLAN

3.1 Simple Replacement

Asset groups that have little consequence of failure or that are run to failure are reactively replaced. The number of predicted failures multiplied by the replacement cost per unit at the year of failure determined the yearly investments for the asset group.

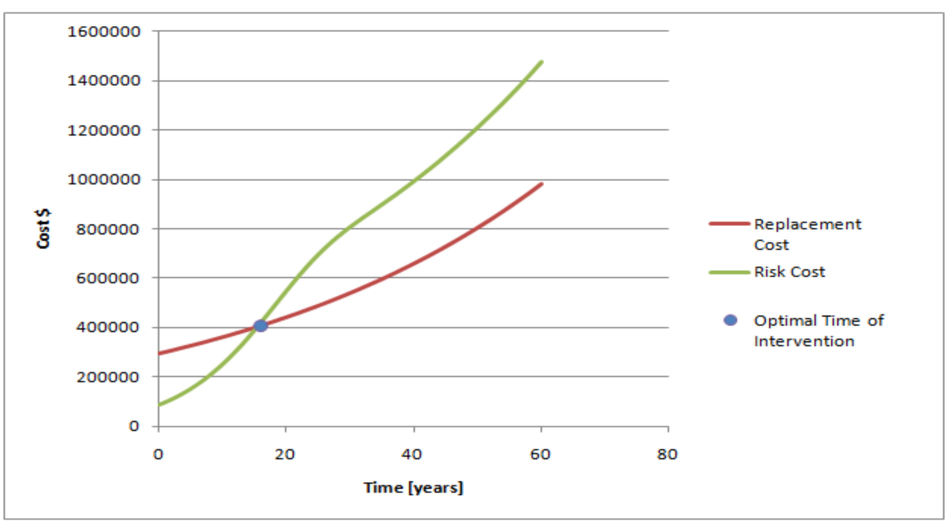
3.2 Risk Analysis

For assets that are have a high consequence of failure (i.e. power transformers), risk analysis determined the economic optimal time of intervention. Planned replacement cost, cost of failure, and risk cost were considered.

The utility's *costs of failure* for an asset can include the replacement cost of the asset, any collateral damage to adjacent equipment, environmental clean-up costs, overtime labour premiums, and the lost revenue. Some utilities also include the cost of interruptions to customers. For this analysis, the cost of failure was estimated as a multiple of its planned replacement cost. For non-critical power transformers, the cost of failure was defined as 1.5 times the planned replacement cost, whereas for critical power transformers, the cost of failure multiple was 2.

The *risk cost* is defined as the failure cost times the probability of failure, probability of failure is dependent on an asset's effective age.

The optimal time of intervention (refurbishment or replacement) was found as the point where the risk cost begins to exceeds the replacement cost. The number of units that were flagged for replacement in a given year times replacement cost for the given year determined the investment required for that year.



4 DATA GAP CLOSURE

Prioritized strategy for data gap closure is included for each asset category using 3 priority levels, from the highest (3 stars) to the lowest (a single star). It is recommended to start collecting condition data for the highest priority condition parameters as this will improve credibility of the Health Index results the most. This is the case for both assets with some condition data available and assets with no condition data available.

C RESULTS AND FINDINGS

THIS PAGE IS INTENTIONALLY LEFT BLANK

1 POWER TRANSFORMERS

The application of power (i.e., substation station) transformers generally involves the step down of a higher to lower voltage. Power transformers vary in capacity and ratings over a broad range.

Power transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary, secondary and, possibly, tertiary windings
- Laminated iron core
- Internal insulating media
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

1.1 Degradation Mechanism

For a majority of transformers, End-of-Life (EOL) is expected to be caused by the failure of the insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture.

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units with a probable high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for substation transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no-load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles
- Maximum loading profile

Thermal Aging:

Thermal aging involves the progress of chemical and physical changes because of chemical degradation reactions, polymerization, depolymerization, and diffusions.

Electrical Aging:

Electrical aging, as it relates to AC, impulse, or switching involves the effects of the following:

- partial discharges
- treeing
- electrolysis
- increased temperatures produced by high dielectric losses
- space charges

Mechanical Aging

Mechanical aging involves the following:

- fatigue failure of insulation components caused by a large number of low-level stress cycles
- thermo mechanical effects caused by thermal expansion and or contraction
- rupture of insulation by high levels of mechanical stress such as may be caused by external forces or operation condition of the equipment
- Insulation creep or flow under electrical, thermal, or mechanical stresses

1.2 Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Insulation	2	Table 1-2	4
2	Visual Inspection	1	Table 1-8	4
3	Service Record	3	Table 1-10	4

1.2.1 Transformer Insulation

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Oil Quality	4	Table 1-3	4
2	Oil DGA	5	Table 1-5	4
3	Winding Doble	5	Table 1-7	4

Table 1-3 Oil Quality Test (n=1) CPF

Description	REFERENCE	CPF
Overall factor is less than 1.2	Formula (1-1)	4
Overall factor between 1.2 and 1.5	Formula (1-1)	3
Overall factor is between 1.5 and 2.0	Formula (1-1)	2
Overall factor is between 2.0 and 3.0	Formula (1-1)	1
Overall factor is greater than 3.0	Formula (1-1)	0

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

$$\textit{Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{\sum \text{Weight} \times 4} \qquad (1\text{-}1)$$

Table 1-4 Oil Quality Factor

Description	Factor				
	1	**2**	**3**	**4**	**Weight**
Moisture PPM	*<=20*	*<=30*	*<=40*	*>40*	3
Dielectric Str. kV	*>40*	*>30*	*>20*	*< 20*	2
Color	*<1.5*	*1.5-2*	*2-2.5*	*> 2.5*	2
Acid Number ($\leq$ 69 kV)	*< 0.05*	*0.05-0.1*	*0.1-0.2*	*>0.2*	1

Table 1-5 Oil DGA (n=2) CPF

Description	REFERENCE	CPF
DGA overall factor is less than 1.2	Formula (1-2)	4
DGA overall factor between 1.2 and 1.5	Formula (1-2)	3
DGA overall factor is between 1.5 and 2.0	Formula (1-2)	2
DGA overall factor is between 2.0 and 3.0	Formula (1-2)	1
DGA overall factor is greater than 3.0	Formula (1-2)	0

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

$$\textit{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight} \quad (1\text{-}2)$$

Table 1-6 Oil DGA Factor

Description	Factor						Weight
	1	2	3	4	5	6	
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 (Carbon Monoxide)	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2 (Carbon Dioxide)	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

Table 1-7 Winding Doble (n=3) CPF

Power Factor (%)	CPF
0-0.04	4
0.05-0.4	3
0.5-0.9	2
1.0-1.9	1
2+	0

1.2.2 Transformer Visual Inspection

Table 1-8 Visual Inspection (m=2) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Tank oil leak	1	Table 1-9	4
2	Oil conservator	1	Table 1-9	4

Table 1-9 OK/Not OK Description and Score CPF

Description	Score
Check mark	4
No check mark	0

1.2.3 Transformer Service Record

Table 1-10 Service Record (m=3) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	REFERENCE	$CPF_{n.max}$
1	Age	2	Table 1-11	4
2	Loading	1	Formula (1-3)	4

Table 1-11 Age (n=1) CPF

Age	Score
0-19	4
20-29	3
30-44	2
45-54	1
55+	0

The *load factor* is the monthly 15 minute peak load of the transformer divided by the transformer's nameplate rating. The *overall factor* is based on the summation of all monthly load factors.

$$\textit{Overall Factor} = \frac{\sum CPF_i}{\sum CPF} \times 4 \qquad (1\text{-}3)$$

Table 1-12 Loading (n=2) CPF

Monthly Load Factor	CPF
0	4
0.6	3
0.8	2
1	1
1.2	0

1.3 Health Index Distribution

GHESI owns and operates two distribution substation power transformers. There was sufficient data for both units.

The Health Indexing Result by Unit and Percentage are presented below:

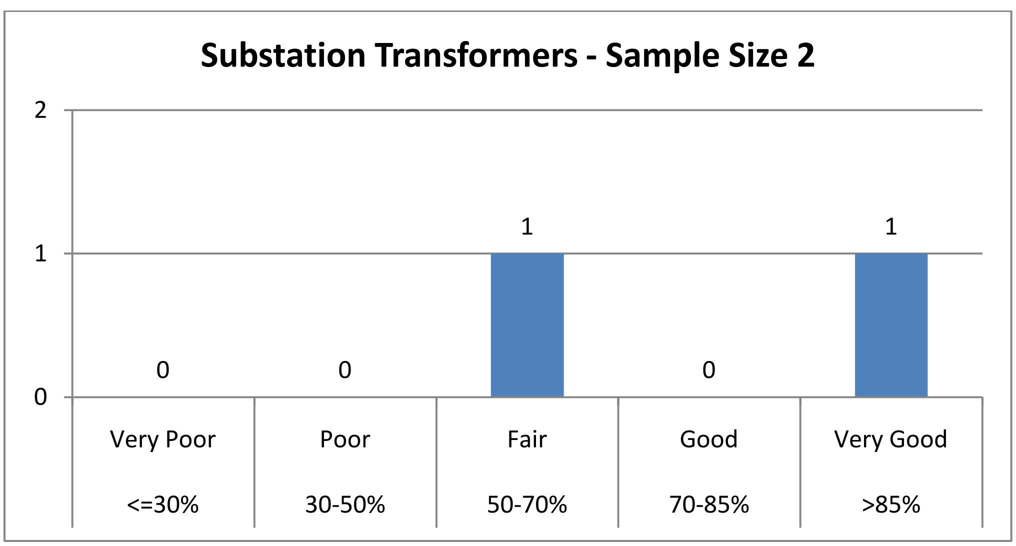


Figure 1-1 Health Index Distribution by Unit

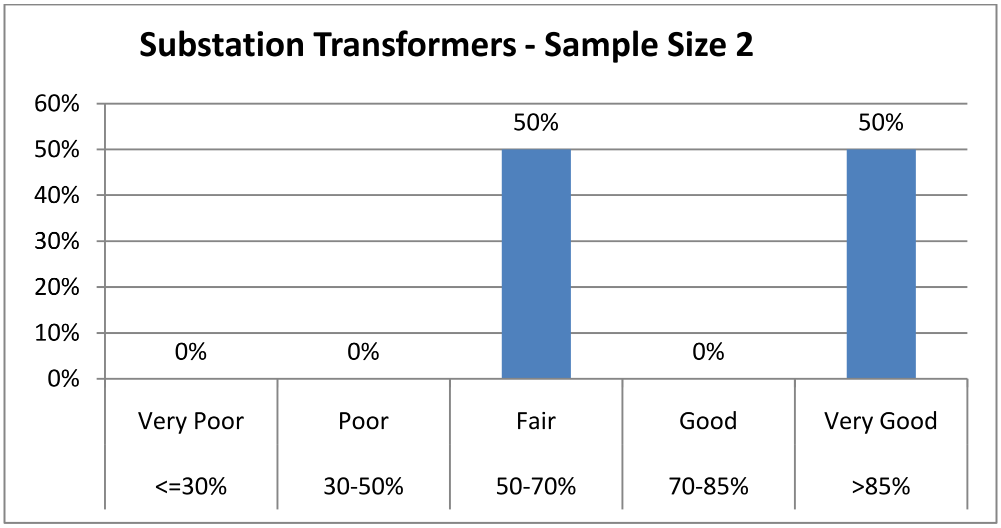


Figure 1-2 Health Index Distribution by Percentage

1.4 Capital Replacement Plan

Figure 1-3 shows the number of Transformer units that will need to be replaced over the next 20 years. Only one of the Substation Transformers (MS1) is expected to be replaced in the next 20 years. As such Levelized Capital Replacement Plan is not required.

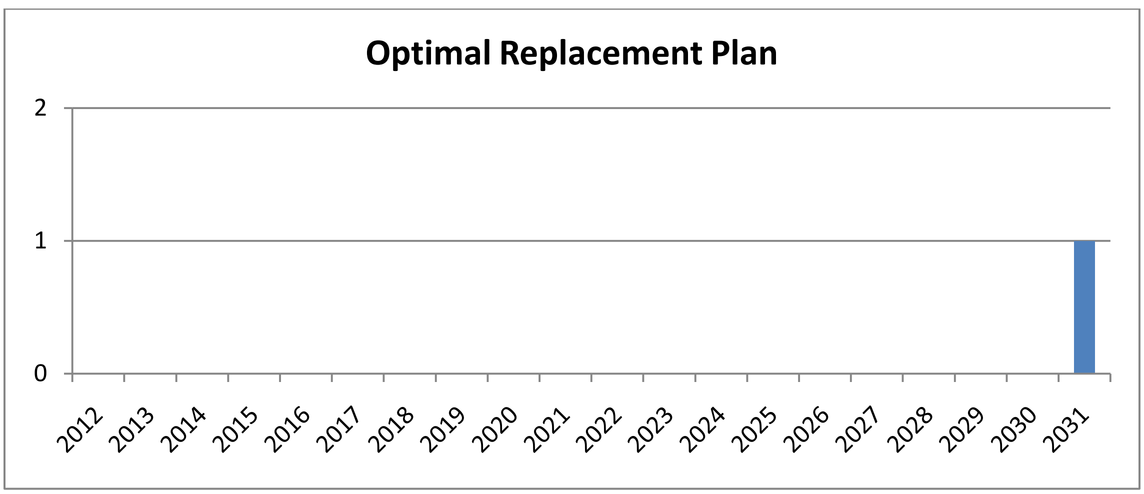


Figure 1-3 Capital Replacement Plan

1.5 Data Gap Closures

The following table summarizes the data gap for power transformers in this project.

Table 1-13 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Visual inspection	Grounding	✯

2 POLE TOP TRANSFORMERS

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

2.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

2.2 Condition and Sub-Condition Parameters

Table 2-1 Condition Weights and Maximum CPS

M	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Operating practices	1	Table 2-2	4
2	Service record	2	Table 2-4	4

2.2.1 Transformer Operating Practices

Table 2-2 Operating Practices (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Number of Customers	1	Table 2-3	4

Table 2-3 Number of Customers Description and Score (n=1) CPF

Customers	Score
0-9	4
10-19	3
20-39	2
40+	0

2.2.2 Transformer Service Record

Table 2-4 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Age	1	Table 2-5	4
2	Loading	1	Table 2-6	4

Table 2-5 Age Description and Score (n=1) CPF

Age	Score
0-14	4
15-24	3
25-29	2
30-49	1
40+	0

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating} \qquad (2\text{-}1)$$

Table 2-6 Loading Description and Score (n=2) CPF

Load Factor	Score
0	4
0.6	3
0.8	2
1	1
1.2	0

2.3 Health Index Distribution

The total population of assets for this category is 1799. The Sample Size or total number of assets within the population that have sufficient data is 1789 (99% of the population).

The installation year was assumed to the transformers age. The other condition parameter was the number of customers serviced by the transformer.

The Health Indexing Result by Unit and Percentage are presented below:

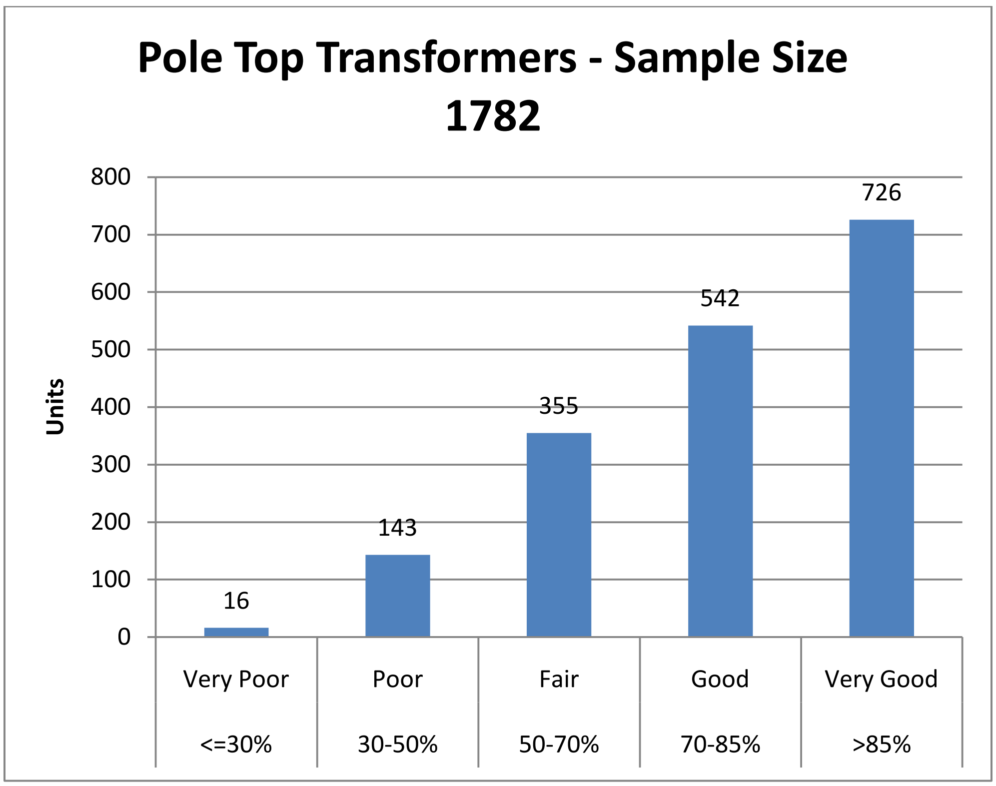


Figure 2-1 Health Index Distribution by Unit

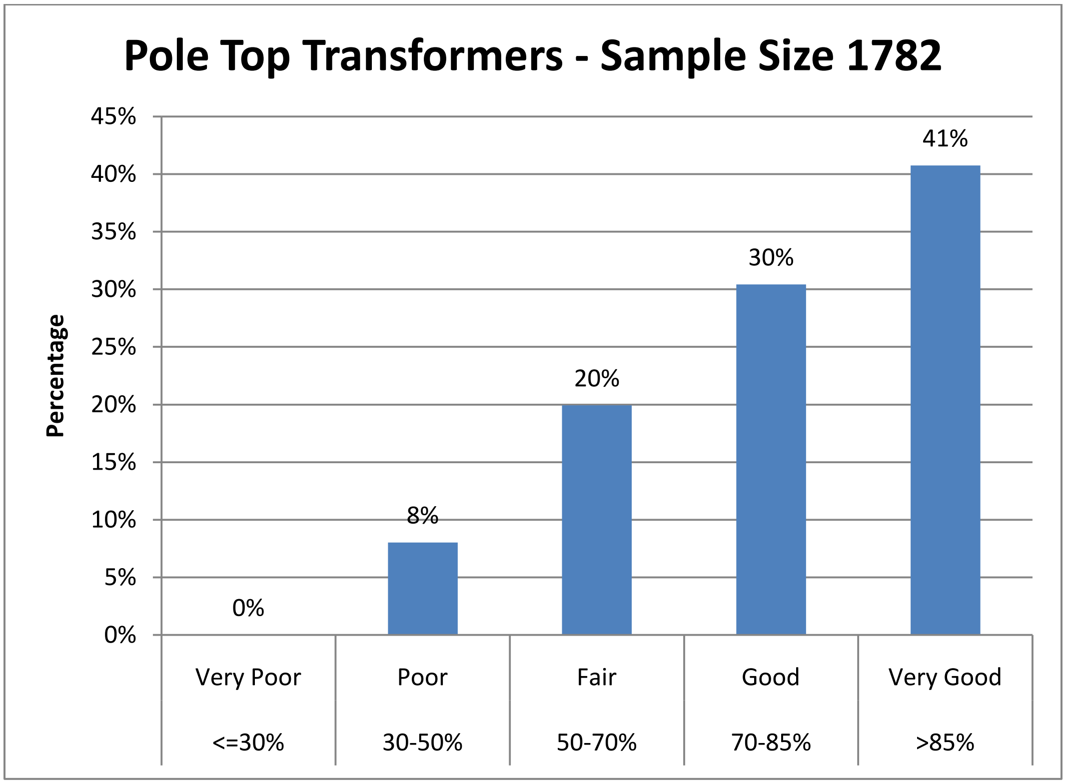


Figure 2-2 Health Index Distribution by Percentage

2.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

2.4.1 Optimal Replacement Plan

Figure 2-3 shows the number of Transformer units that will need to be replaced over the next 20 years.

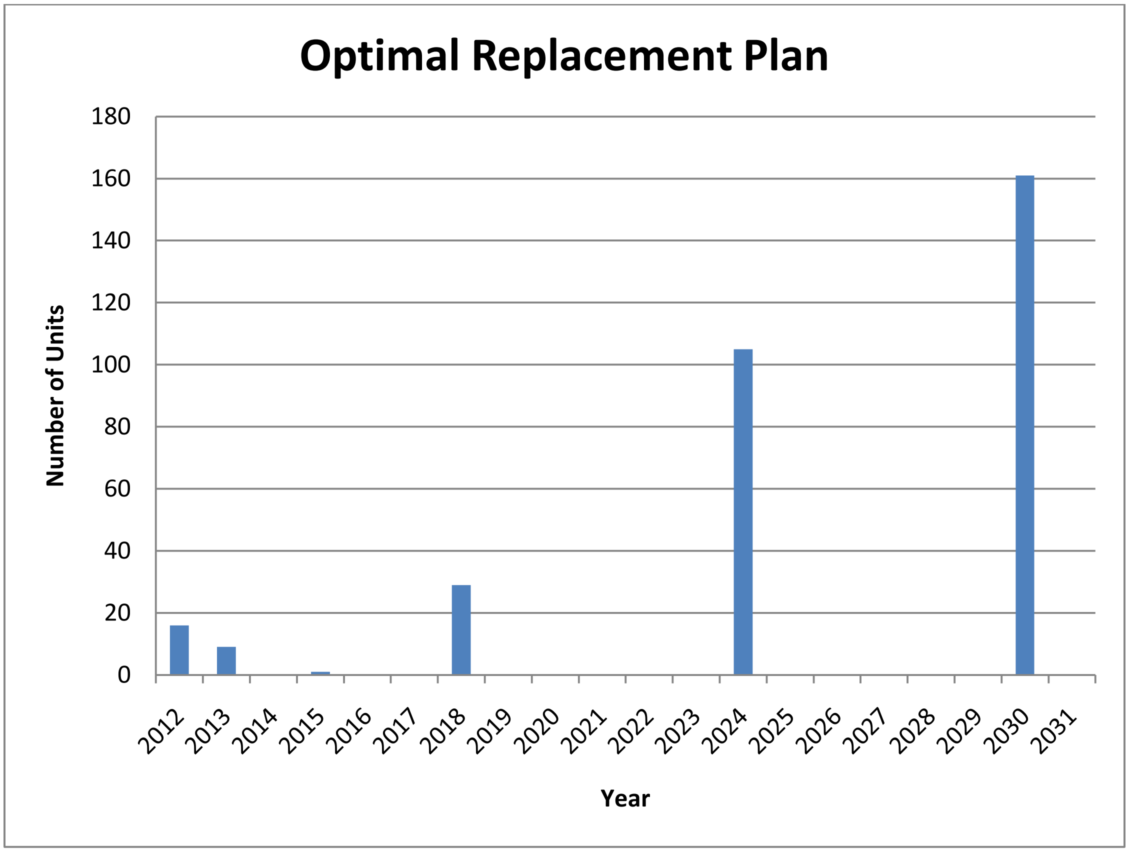


Figure 2-3 Optimal Replacement Plan

2.4.2 Levelized Capital Replacement Plan

For this asset category, the optimal replacement plan suggests replacing 16 units in 2012, 9 units in 2013, 35 units in 2018, 104 units in 2024 and 161 units in 2030. While this is optimal based on the Pole Mounted Transformers HI scores, it may not be ideal financially.

Pole Mounted Transformers are typically replaced **reactively** (end of life.) A Levelized approach means replacing assets before they are estimated to fail. The Levelized replacement plan allows for Transformers that would optimally be replaced in 2018, 2024 and 2030 to be replaced over a period of 5 years preceding failure.

Figure 2-4 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

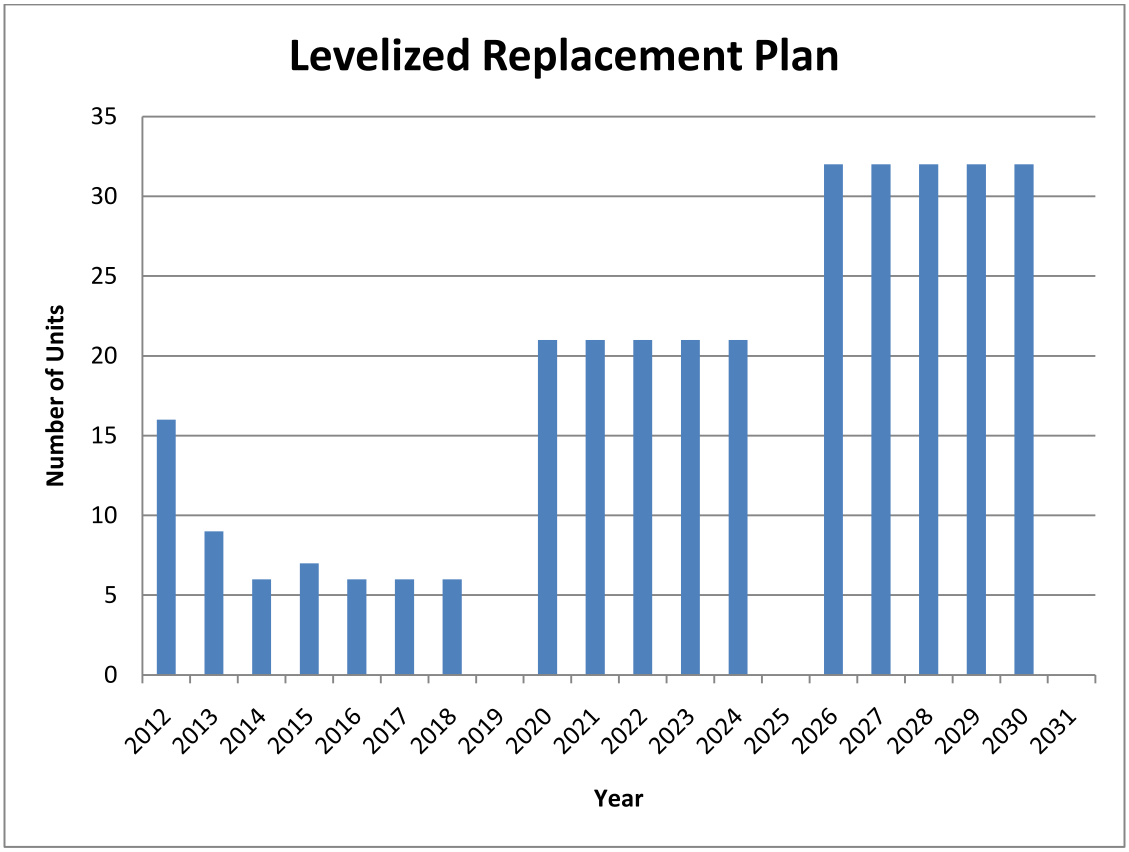


Figure 2-4 Levelized Replacement Plan

2.5 Data Gap Closures

The following table summarizes the data gap for pole mounted transformers in this project.

Table 2-7 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Corrosion	☆ ☆
Connection & insulation	Oil leak	☆ ☆

As a pole mounted transformer is a run-to-failure asset, its service record has much impact on its life cycle. While corrosion and oil leak provide visual inspection on the external signs of degradation, its loading history can be used to estimate its actual aging process.

3 PAD MOUNTED TRANSFORMERS

Pad Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure.

3.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

3.2 Condition and Sub-Condition Parameters

Based on the expert opinion of GHESI staff, those Pad Mounted Transformers with Live fronts have a Health Index score no greater than 70% ("Fair").

Table 3-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Physical condition	3	Table 3-2	4
2	Connection & insulation	5	Table 3-4	4
3	Service record	5	Table 3-5	4

3.2.1 Transformer Physical Condition

Table 3-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Access	1	Table 3-3	4
2	Base	2	Table 3-3	4

Table 3-3 Okay/Not Okay Description and Score CPF

Description	CPF
TRUE	0
FALSE	4

3.2.2 Transformer Connection and Insulation

Table 3-4 Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Oil contamination	2	Table 3-3	4
2	Enclosure	1	Table 3-3	4
3	Connection	2	Table 3-3	4
4	Bushing	4	Table 3-3	4

3.2.3 Transformer Service Record

Table 3-5 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Inspection	4	Table 3-6	4
2	Age	1	Table 3-7	4
3	Loading	1	Table 3-8	4

Table 3-6 Inspection Description and Score (n=1) CPF

Description	Score
PROBLEM	0
NO PROBLEM	4
FIXED	3
NOT IN SERVICE	N/A

Table 3-7 Age Description and Score (n=2) CPF

Description	Score
0-14	4
15-29	3
30-44	2
45-49	1
55+	0

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating} \tag{3-1}$$

Table 3-8 Loading Description and Score (n=3) CPF

Loading Factor	Score
0	4
0.6	3
0.8	2
1	1
1.2	0

3.3 Health Index Distributions

The total population of assets for this category is 3623. The Sample Size or total number of assets within the population that have data is 3623 (100% of the Assets).

The Health Indexing Result by Unit and Percentage are presented below:

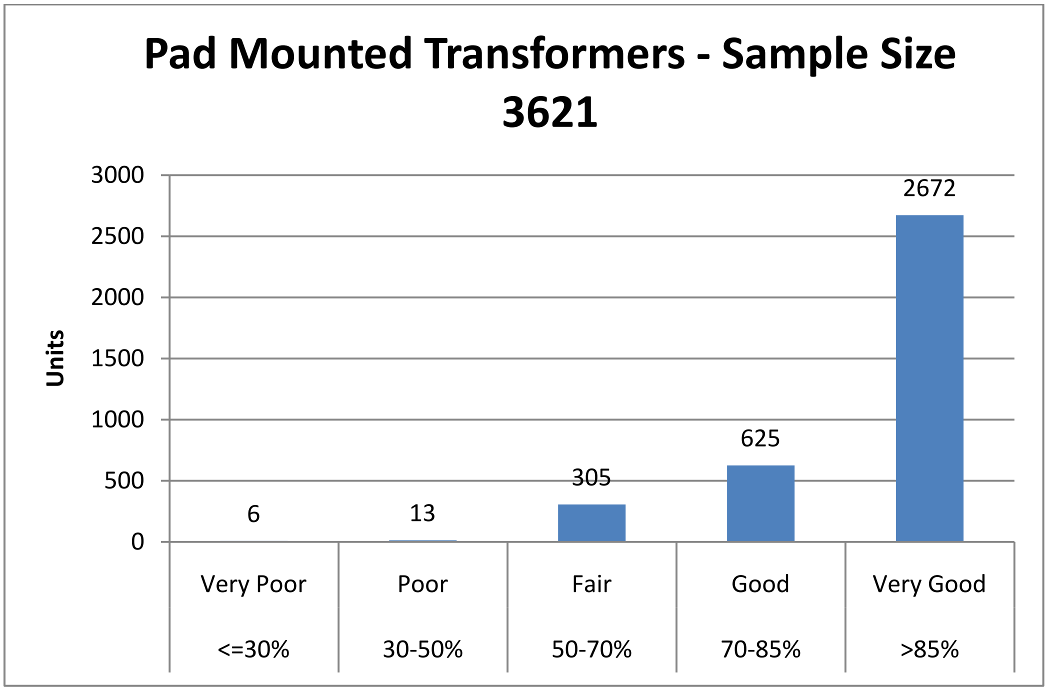


Figure 3-1 Health Index Distribution by Units

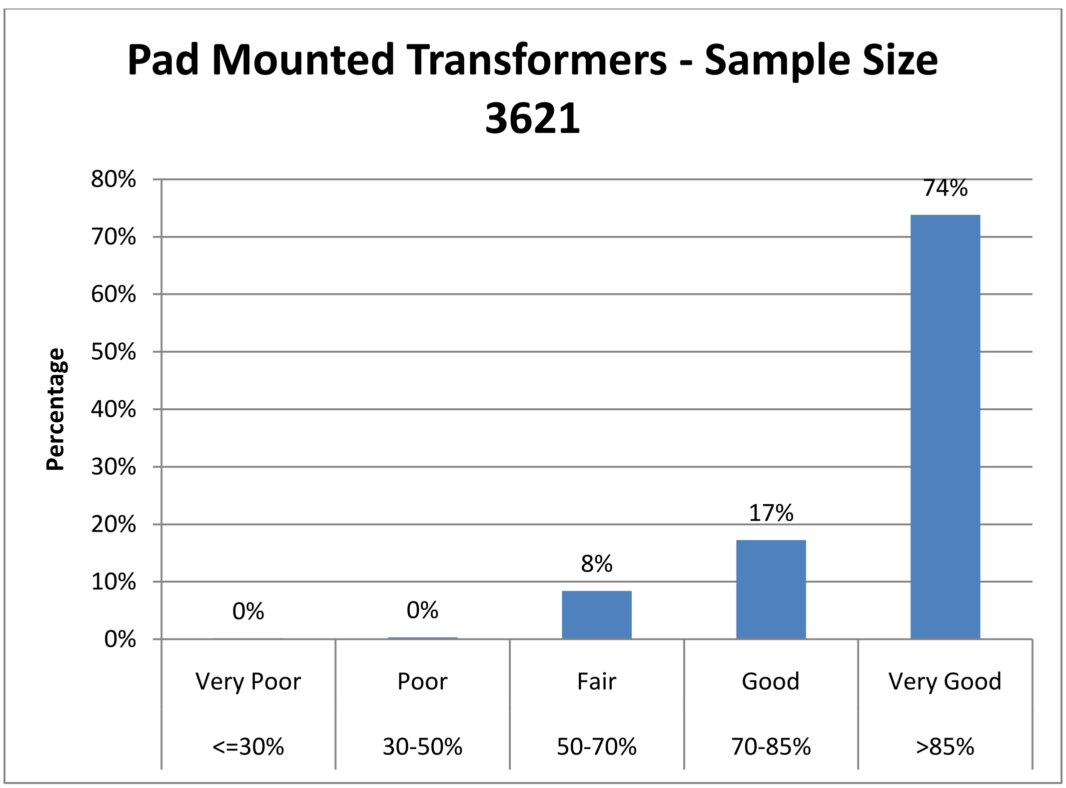


Figure 3-2 Health Index Distribution by Percentage

3.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

3.4.1 Optimal Capital Replacement Plan

Figure 3-3 shows the number of Transformer units that will need to be replaced over the next 20 years.

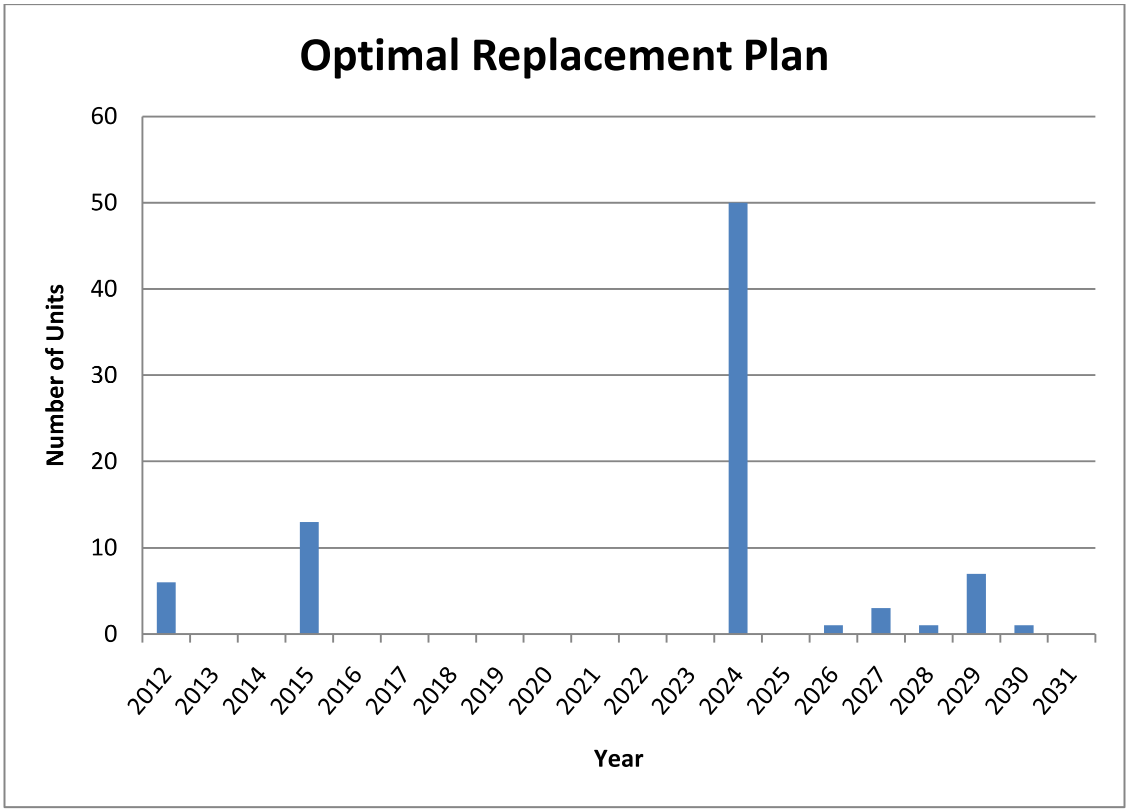


Figure 3-3 Optimal Replacement Plan

3.4.2 Levelized Capital Replacement Plan

Pad Mounted Transformers are replaced **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of time. Figure 3-4 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time, it is the same as the optimal replacement plan. For example, the 6 Pad Mounted Transformers that would optimally be replaced next year and the 12 Pad Mount Transformers to be replaced in 2015 can be replaced over the a period of time after their failure date.

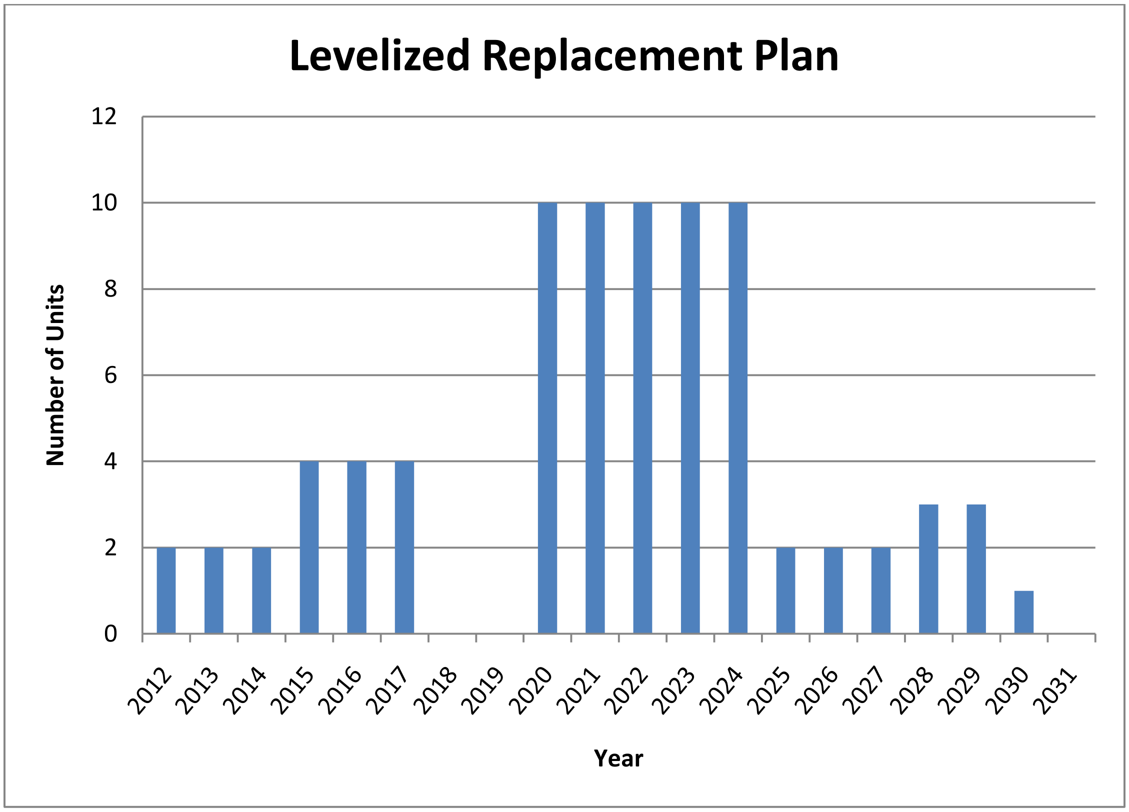


Figure 3-4 Levelized Replacement Plan

3.5 Data Gap Closures

The following table summarizes the data gap for pad mounted transformers in this project.

Table 3-9 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Sealing & connection	Grounding	☆
	IR thermography	☆ ☆ ☆

IR thermography is a useful approach in detecting hot spots due to loose connection or leakage. In this project, it also can address the transformer loading status, when the data on such parameter are unavailable.

4 SUBMERSIBLE TRANSFORMERS

Distribution submersible transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

4.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

4.2 Condition and Sub-Condition Parameters

Table 4-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Operating Practices	1	Table 4-2	4
2	Service Record	2	Table 4-4	4

4.2.1 Transformer Operating Practices

Table 4-2 Operating Practices (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Customers	1	Table 4-3	4

Table 4-3 Number of Customers Description and Score (n=1) CPF

Customers	Score
0-9	4
10-19	3
20-39	2
40+	0

4.2.2 Transformer Service Record

Table 4-4 Service Record (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Age	1	Table 4-5	4
2	Loading	1	Table 4-6	4

Table 4-5 Age Description and Score (n=1) CPF

Age	Score
0-14	4
15-24	3
25-29	2
30-49	1
40+	0

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating} \quad (4\text{-}1)$$

Table 4-6 Loading Description and Score (n=2) CPF

Load Factor	Score
0	4
0.6	3
0.8	2
1	1
1.2	0

4.3 Health Index Distribution

The total population of assets for this category is 41. The Sample Size or total number of assets within the population that have sufficient data is 39 (95% of the population).

The installation year was assumed to the transformers age. The other condition parameter was the number of customers serviced by the transformer.

The Health Indexing Result by Unit and Percentage are presented below:

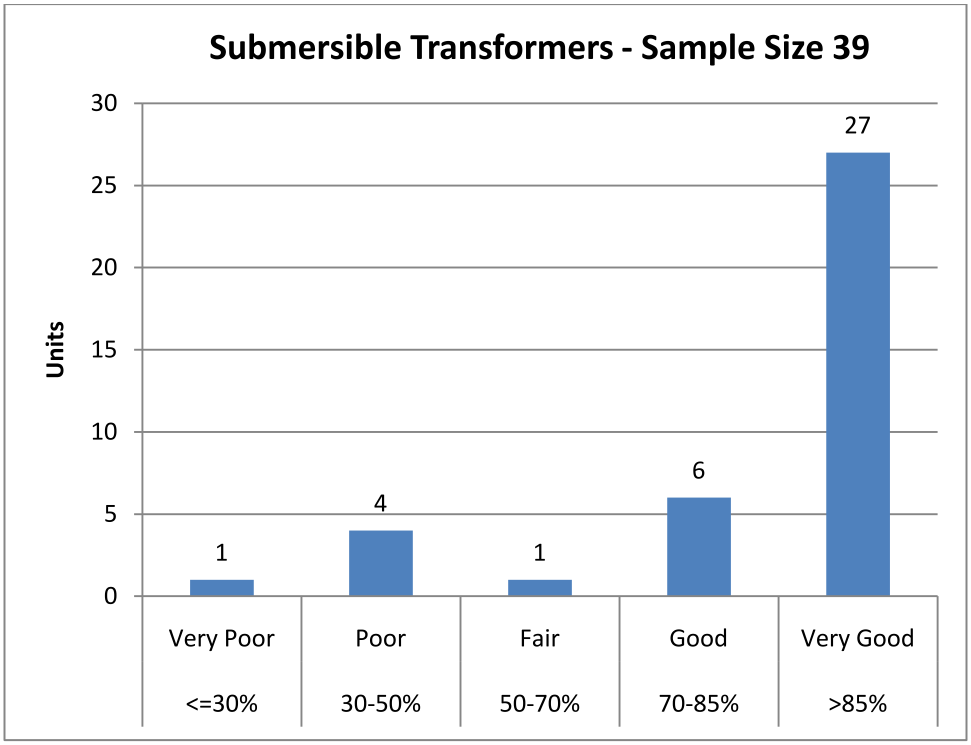


Figure 4-1 Health Index Distribution by Unit

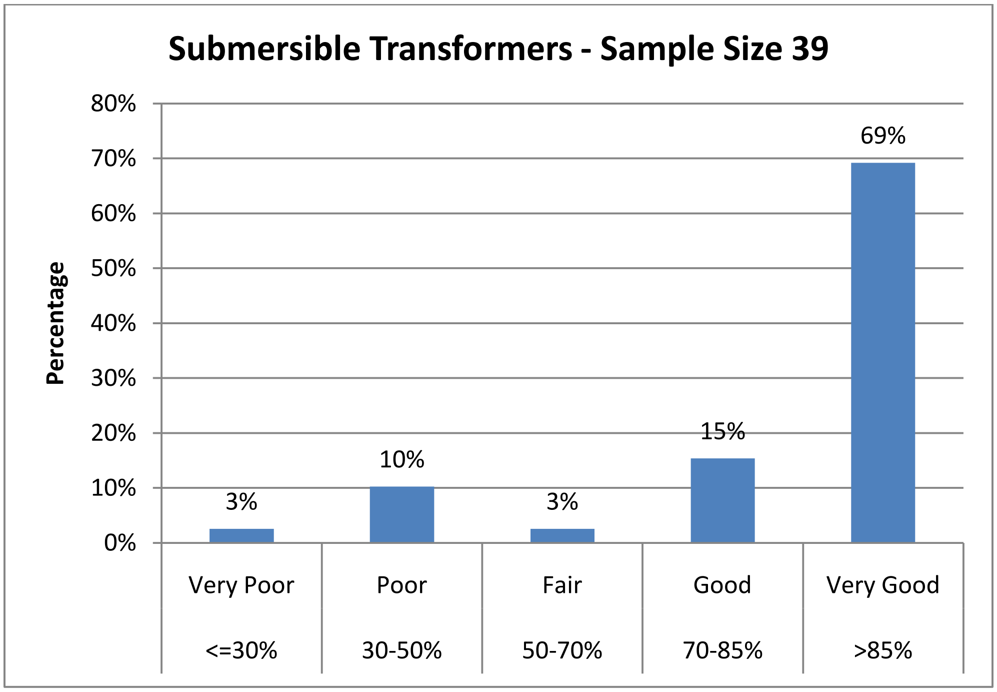


Figure 4-2 Health Index Distribution by Percentage

4.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 40 years the probability of failure is 90%.

4.4.1 Optimal Replacement Plan

Figure 4-3 shows the number of Transformer units that will need to be replaced over the next 20 years.

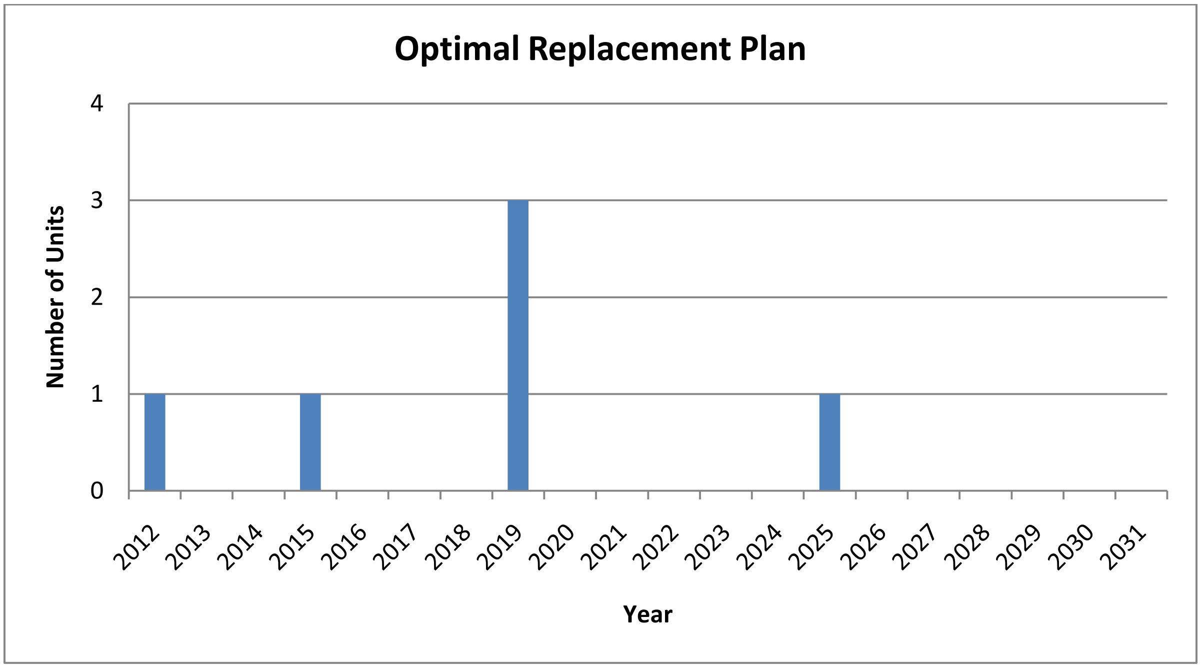


Figure 4-3 Optimal Replacement Plan

4.4.2 Levelized Capital Replacement Plan

For this asset category, the optimal replacement plan suggests replacing 3 units in 2019.

Submersible Transformers are typically replaced **reactively** (end of life.) Since the HI scores indicate the major group of failures happening in 2019, a Levelized approach means replacing assets before they are estimated to fail. The Levelized replacement plan allows for Transformers that would optimally be replaced in 2019 to be replaced over a period of 3 years.

Figure 4-4shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

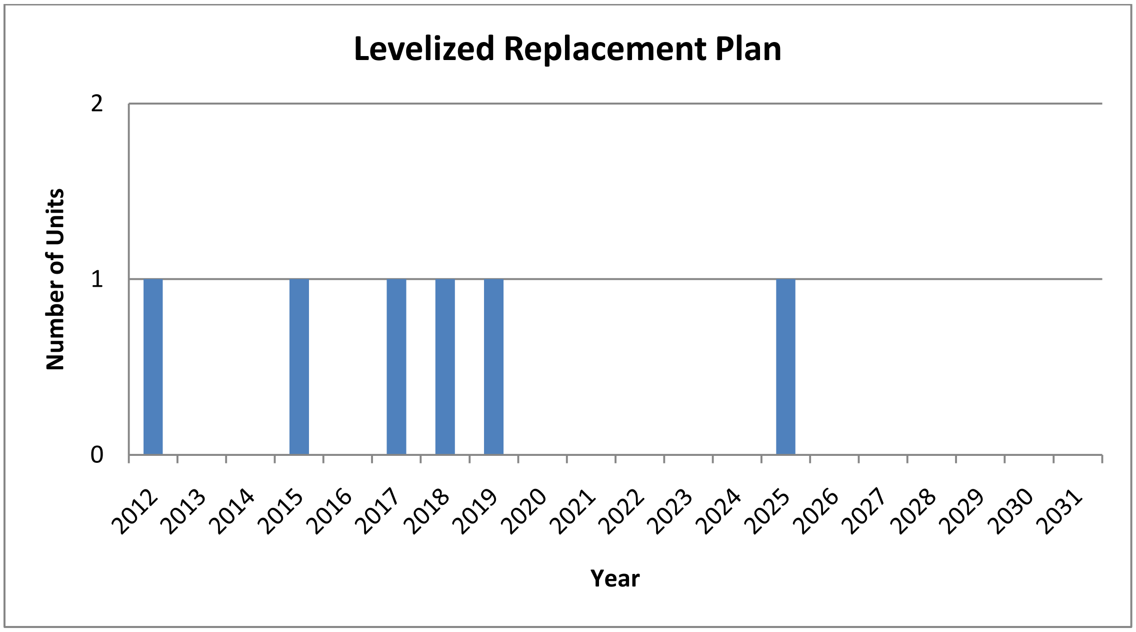


Figure 4-4 Levelized Replacement Plan

4.5 Data Gap Closures

The following table summarizes the data gap for submersible transformers in this project.

Table 4-7 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Corrosion	☆ ☆

Corrosion is an external sign of degradation and should be included in visual inspections.

5 VAULT TRANSFORMERS

Distribution submersible transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

5.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

5.2 Condition and Sub-Condition Parameters

Table 5-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Physical condition	3	Table 5-2	4
2	Connection & insulation	5	Table 5-4	4
3	Service record	5	Table 5-5	4

5.2.1 Transformer Physical Condition

Table 5-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Access	1	Table 5-3	4
2	Base	2	Table 5-3	4

Table 5-3 Okay/Not Okay Description and Score CPF

Description	Score
TRUE	0
FALSE	4

5.2.2 Transformer Connection and Insulation

Table 5-4 Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Oil contamination	2	Table 5-3	4
2	Enclosure	1	Table 5-3	4
3	Connection	2	Table 5-3	4
4	Bushing	4	Table 5-3	4

5.2.3 Transformer Service Record

Table 5-5 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Inspection result	4	Table 5-6	4
2	Age	1	Table 5-7	4
3	Loading	1	Table 5-8	4

Table 5-6 Inspection Description and Score (n=1) CPF

Description	Score
PROBLEM	0
NO PROBLEM	4
FIXED	3
NOT IN SERVICE	N/A

Table 5-7 Age Description and Score (n=2) CPF

Description	Score
0-14	4
15-29	3
30-44	2
45-49	1
55+	0

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating} \qquad (5\text{-}1)$$

Table 5-8 Loading Description and Score (n=3) CPF

Load Factor	Score
0	4
0.6	3
0.8	2
1	1
1.2	0

5.3 Health Index Distribution

The total population of assets for this category is 82. The Sample Size or total number of assets within the population that have sufficient data is 82 (100% of the population). The installation year was assumed to the transformers age. The other condition parameter was the number of customers serviced by the transformer.

The Health Indexing Result by Unit and Percentage are presented below:

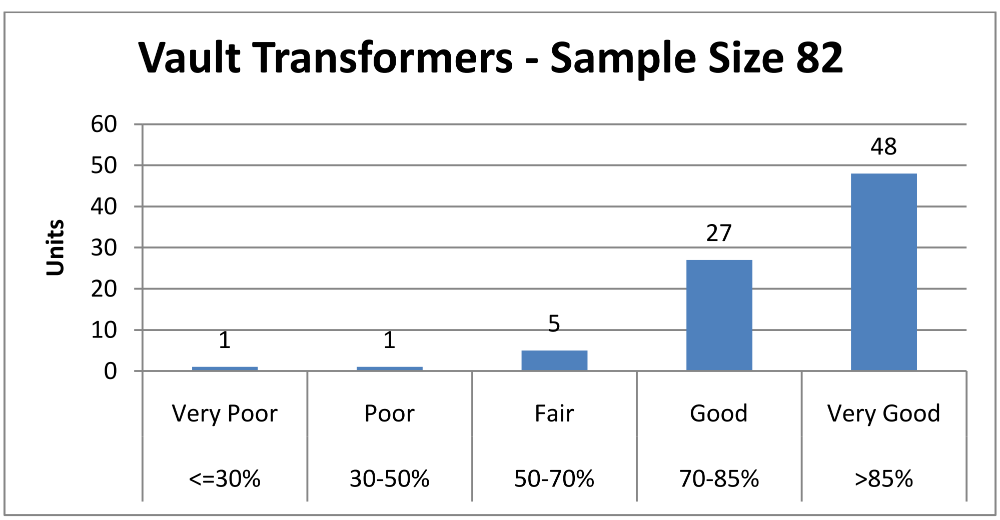


Figure 5-1 Health Index Distribution by Unit

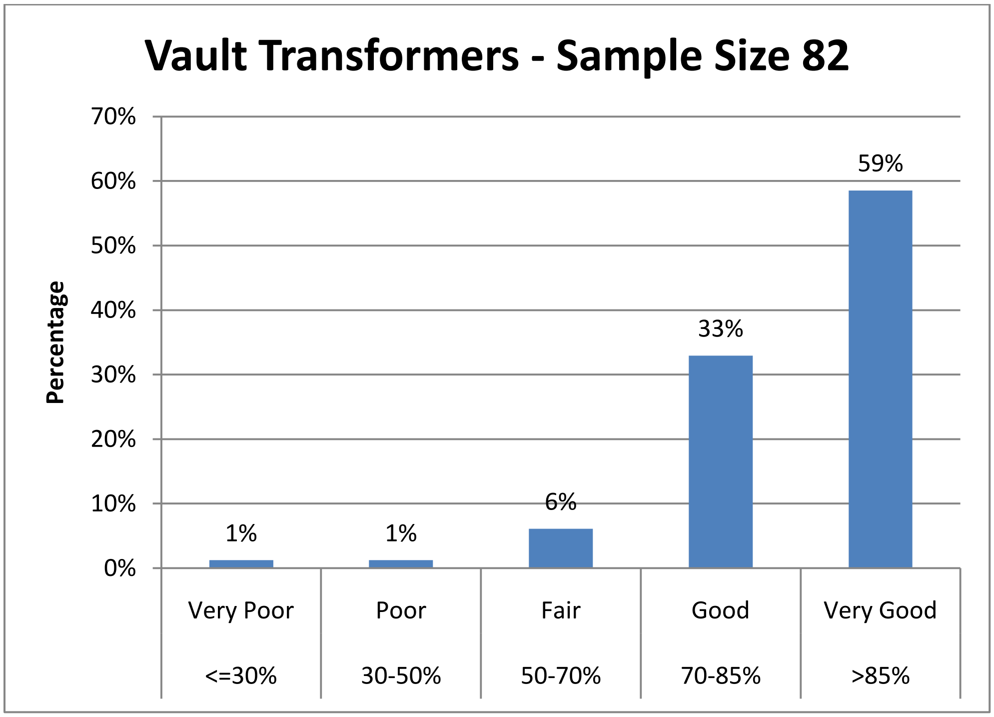


Figure 5-2 Health Index Distribution by Percentage

5.4 Capital Replacement Plan

Since there was **no replacement cost** available at this time, Vault Transformers are not included in the Capital Replacement Plan.

5.5 Data Gap Closures

The following table summarizes the data gap for vault transformers in this project.

Table 5-9 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Sealing & connection	Grounding	☆
	IR thermography	☆ ☆ ☆

IR thermography is a useful approach in detecting hot spots due to loose connection or leakage.

6 OVERHEAD SWITCHES

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang. For the purposes of this Report the switches include Fuse Cutouts, Load Breakers and Disconnect Switches.

6.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Non-functioning padlocks
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions where the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

6.2 Condition and Sub-Condition Parameters

Table 6-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Operating practices	1	Table 6-2	4
2	Service record	2	Table 6-4	4

6.2.1 Switch Operating Practices

Table 6-2 Operating Practices (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Number of Customers	1	Table 6-3	4

Table 6-3 Number of Customers Description and Score (n=1) CPF

Customers	Score
0-9	4
10-19	3
20-39	2
40+	0

6.2.2 Switch Service Record

Table 6-4 Service Record (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Age	1	Table 6-5	4

Table 6-5 Age Description and Score (n=1) CPF

Age	Score
0-14	4
15-24	3
25-29	2
30-49	1
40+	0

6.3 Health Index Distribution

The total population of assets for this category is 237. The Sample Size or total number of assets within the population that have sufficient data is 237 (100% of the population).

The installation year was assumed to the switch age. The other condition parameter was the number of customers serviced by the switch.

The Health Indexing Result by Unit and Percentage are presented below:

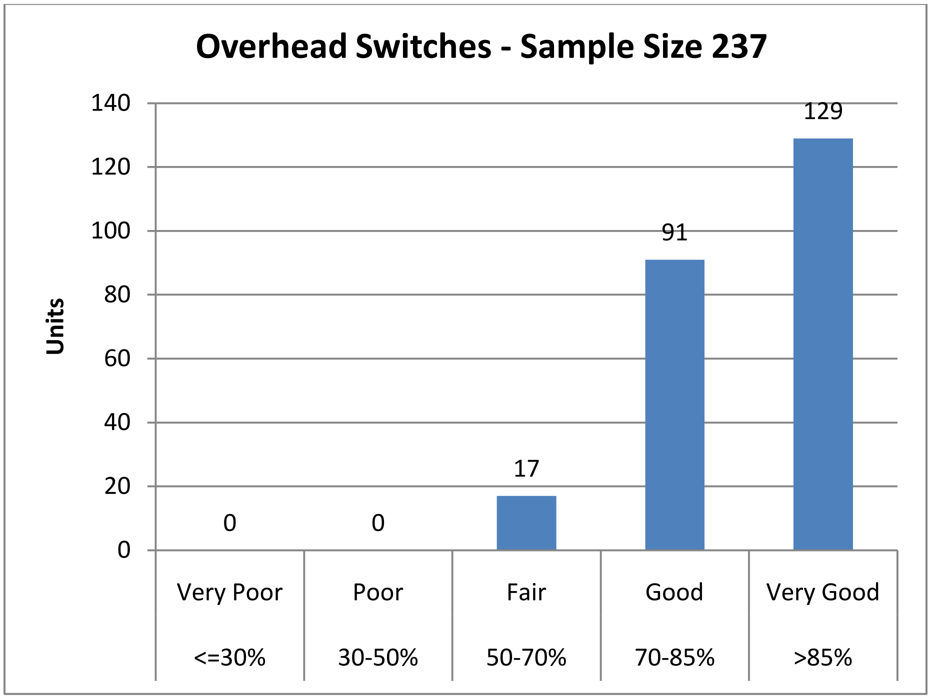


Figure 6-1 Health Index Distribution by Unit

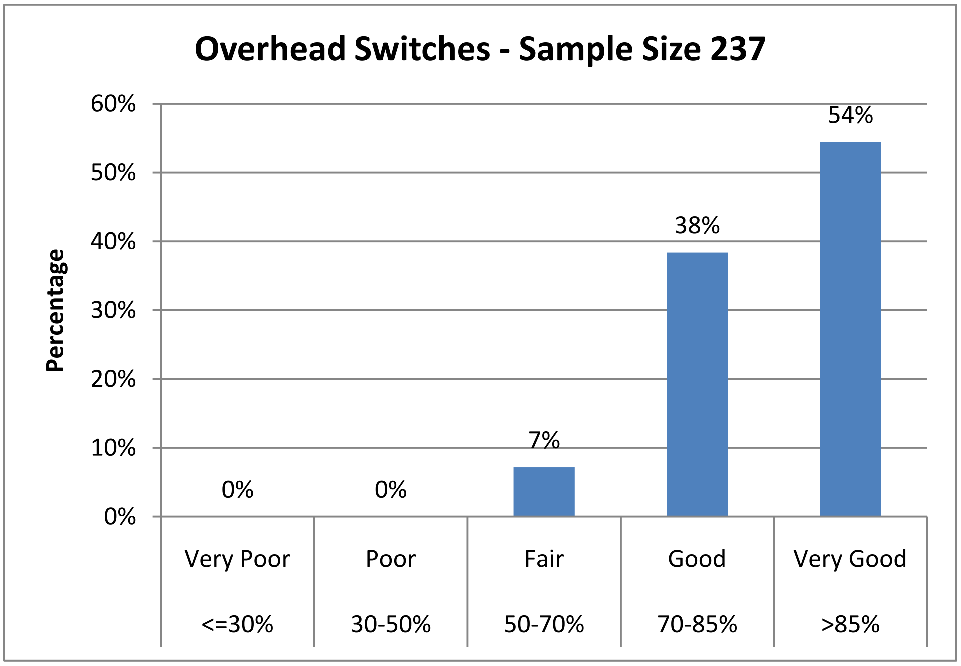


Figure 6-2 Health Index Distribution by Percentage

6.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

6.4.1 Optimal Replacement Plan

Figure 6-3 shows the number of Transformer units that will need to be replaced over the next 20 years.

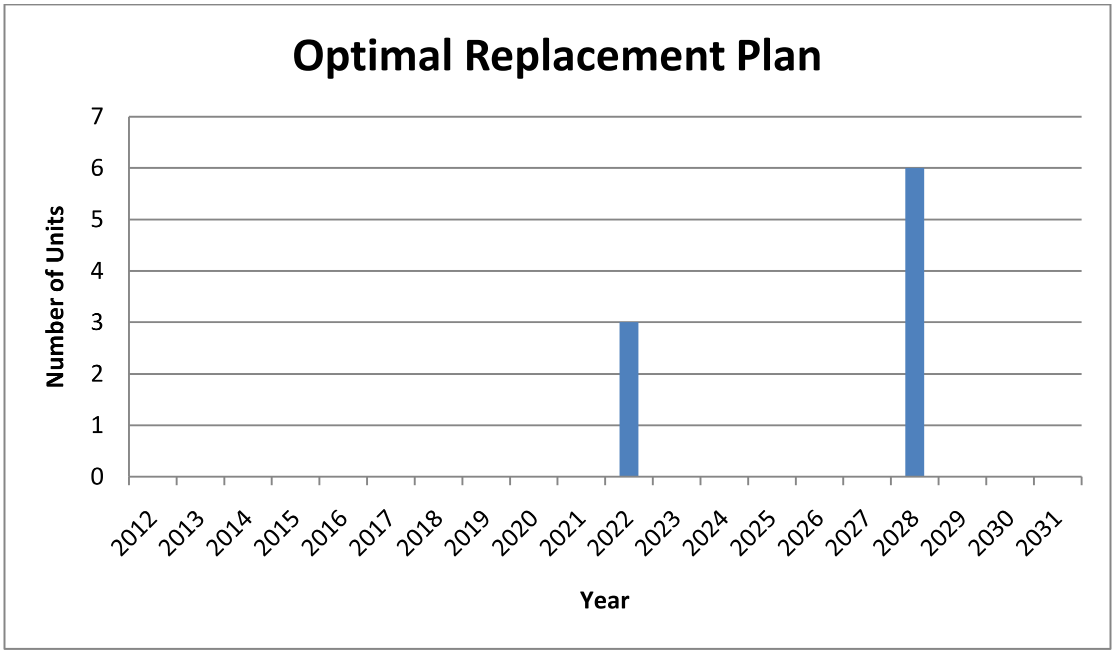


Figure 6-3 Optimal Replacement Plan

6.4.2 Levelized Capital Replacement Plan

For this asset category, the optimal replacement plan suggests replacing 3 units in 2022 and 6 units in 2028. While this is optimal based on the HI scores, it may not be ideal financially.

Overhead Switches are typically replaced **reactively** (end of life.) Since the HI scores indicate the major group of failures happening in 2022 and 2028, a Levelized approach means replacing assets before they are estimated to fail. The Levelized replacement plan allows for Transformers that would optimally be replaced in 2022 and 2028 to be replaced over a period of 5 years.

Figure 6-4 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

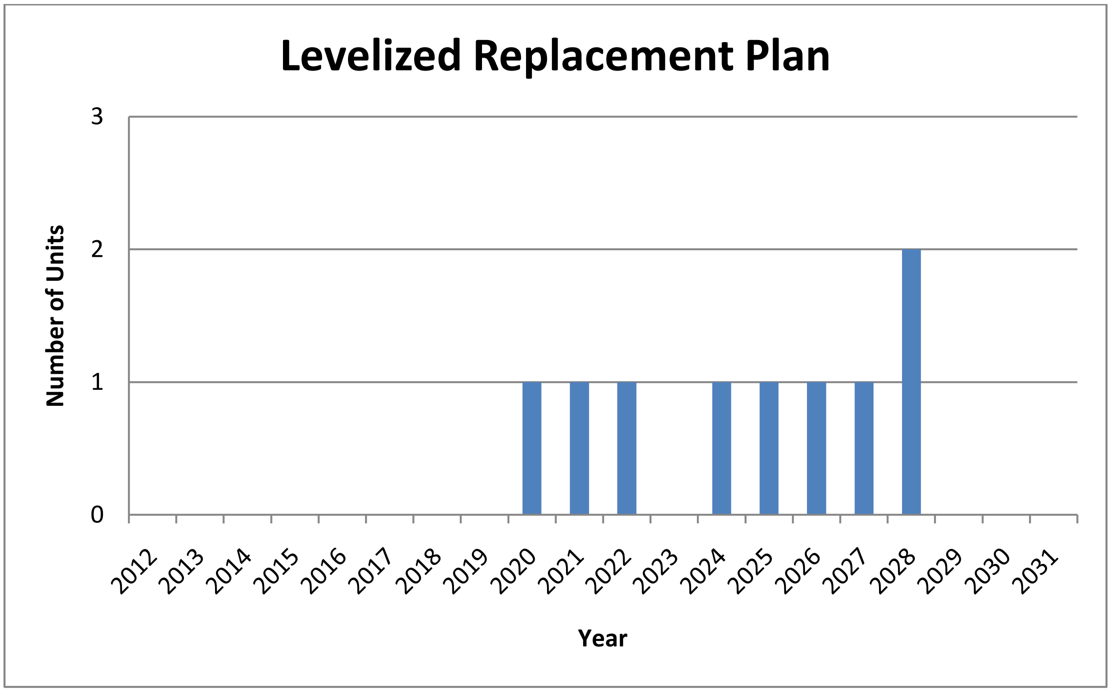


Figure 6-4 Levelized Replacement Plan

6.5 Data Gap Closures

The following table summarizes the data gap for overhead switches in this project.

Table 6-6 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Operating mechanism	Motor/manual operation	✮ ✮ ✮
	Switch mounting	✮
Arc extinction	Arc horn/interrupter	✮ ✮
	Switch blade	✮ ✮
Insulation condition	Insulator	✮ ✮

Motor/manual operation addresses the status of switch mechanism. This is important as it can reveal the mechanical function status of operating mechanism. Switch mounting can reveal the misalignment of blades.

Arc horn/interrupter and switch blade together address the possible ability of a switch during its breaking operation.

Insulator status is an indication of whether there is any chance of a flashover failure.

7 PAD MOUNTED SWITCHGEAR

This asset class consists of pad mounted switchgear. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements.

7.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Non-functioning padlocks
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions where the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

7.2 Condition and Sub-condition Parameters

Table 7-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Maintenance	1	Table 7-2	4
2	Service record	4	Table 7-4	4

7.2.1 Switchgear Maintenance

Table 7-2 Maintenance (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Dry Ice	4	Table 7-3	4

Table 7-3 Dry Ice Description and Score (n=1) CPF

Description	Score
NEW	4
3	2
9	2

7.2.2 Switchgear Service Record

Table 7-4 Service Record (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Age	1	Table 7-5	4

Table 7-5 Age Description and Score (n=1) CPF

Age	Score
0-14	4
15-24	3
25-29	2
30-49	1
40+	0

7.3 Health Index Distribution

The total population of assets for this category is 61. The Sample Size or total number of assets within the population that have sufficient data is 62 (98% of the population).

The installation year was assumed to the switchgear age.

The Health Indexing Result by Unit and Percentage are presented below:

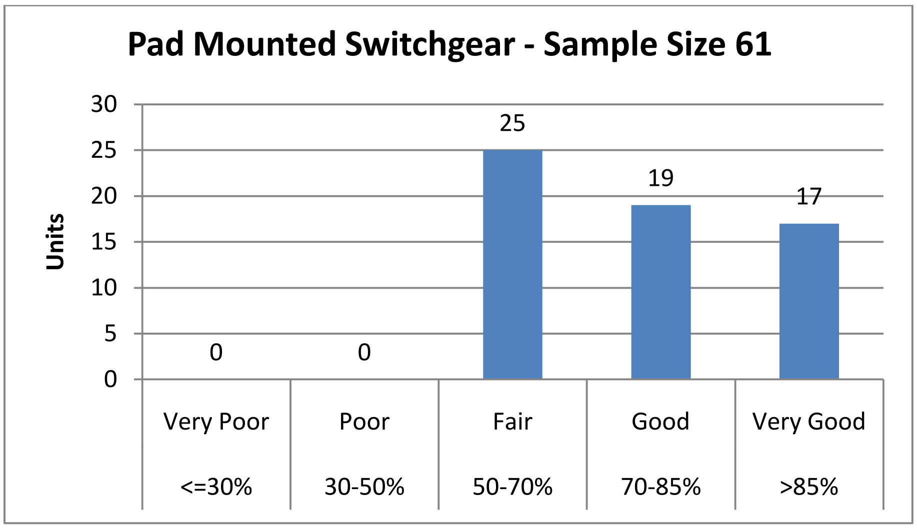


Figure 7-1 Health Index Distribution by Unit

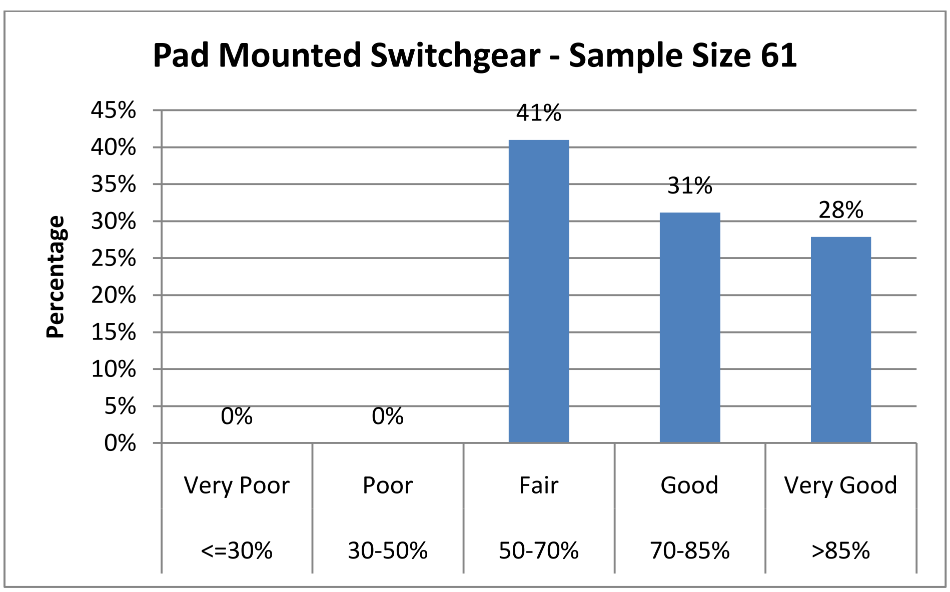


Figure 7-2 Health Index Distribution by Percentage

7.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

7.4.1 Optimal Replacement Plan

Table 7-3 shows the number of Transformer units that will need to be replaced over the next 20 years.

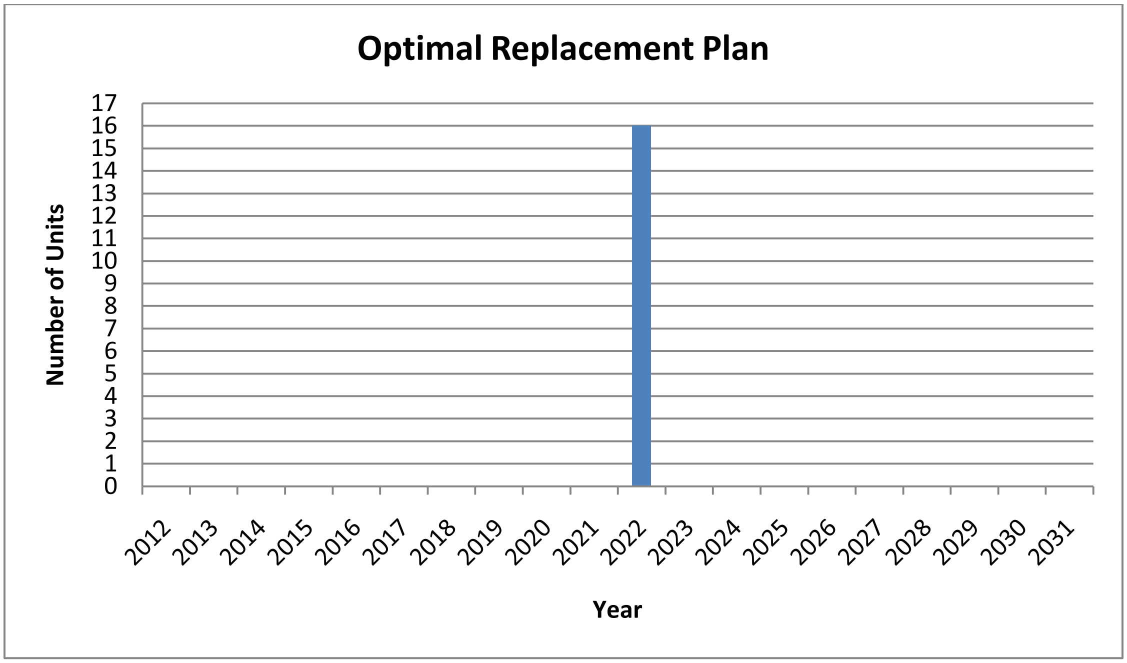


Figure 7-3 Optimal Replacement Plan

7.4.2 Levelized Capital Replacement Plan

For this asset category, the optimal replacement plan suggests replacing 16 units in 2022. While this is optimal based on the HI scores, it may not be ideal financially.

Pad Mounted Switchgear are typically replaced **reactively** (end of life.) Since the HI scores indicate the major group of failures happening in 2022 a Levelized approach means replacing assets before they are estimated to fail. The Levelized replacement plan allows for Transformers that would optimally be replaced in 2022 to be replaced over a period of 4 years.

Table 7-4 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

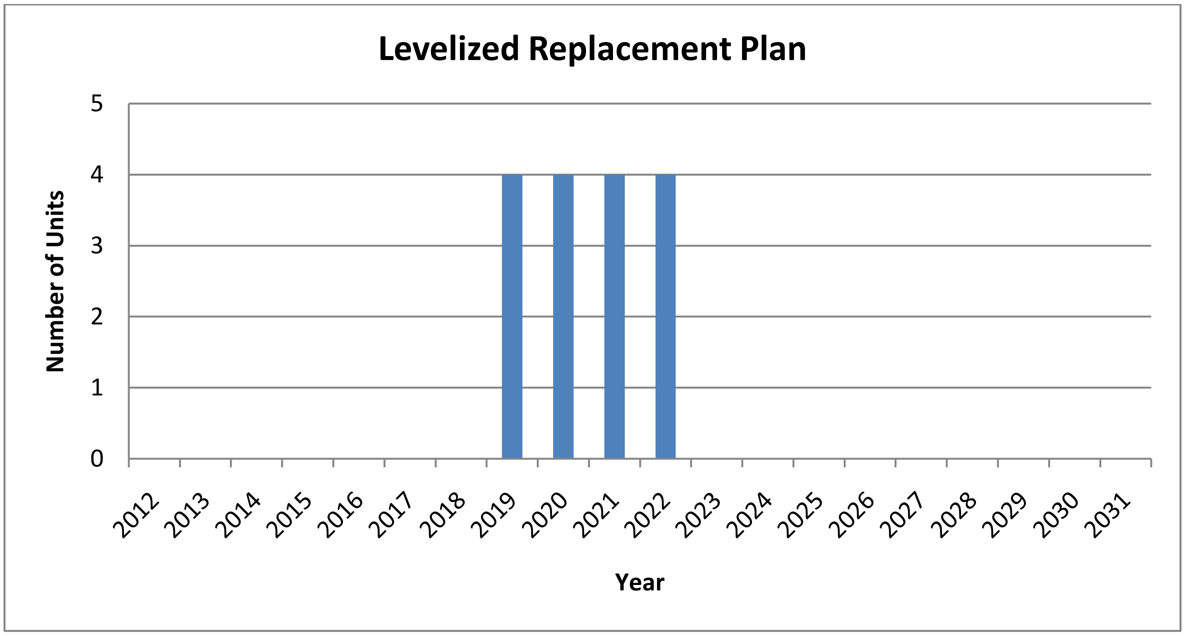


Figure 7-4 Levelized Replacement Plan

7.5 Data Gap Closures

The following table summarizes the data gap for pad mounted switchgear in this project.

Table 7-6 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Base	✮✮
	Access	✮
Switch/fuse condition	Switch/fuse condition	✮✮✮
	Arc chute	✮✮
	Grounding	✮
Insulation	Insulators	✮✮

Switch main contact and its arc suppression parts are the main devices inside pad mounted switchgear.

Count of CM (corrective maintenance) work orders within a standard time period provides a clue on how often failures happen on the unit. A high count number indicates a trend of accelerated deterioration of switch parts.

8 WOOD POLES

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor and guys. The most important component with respect to useful life is the pole itself.

8.1 Degradation Mechanism

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on the electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

There are many factors considered by utilities when establishing condition of wood poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The life expectancy of wood poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

8.2 Condition and Sub-Condition Parameters

Based on the expert opinion of GHESI staff, Douglas Fir Wood Poles have a Health Index score no greater than 30% ("Very Poor").

Table 8-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Pole Strength	5	Table 8-2	4
2	Pole Physical Condition	4	Table 8-4	4
3	Service record	3	Table 8-6	4

8.2.1 Pole Strength

Table 8-2 Pole Strength (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Pole Strength	1	Table 8-3	4

Table 8-3 Strength Description and Score (n=1) CPF

Description (psi)	Score
0-2999	2
3000-5000	3
8000	4

8.2.2 Pole Physical Condition

Table 8-4 Pole Physical Condition (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	WCPFn	TABLE	CPFn.max
1	Decay	1	Table 8-5	4
2	Treatment Required	3	Table 8-5	4
3	Sound Hollow	2	Table 8-5	4
4	Rejected	2	Table 8-5	4
5	Ants	1	Table 8-5	4

Table 8-5 Yes/No Description and Score

Description	Score
TRUE	0
FALSE	4

8.2.3 Pole Service Record

Table 8-6 Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Age	1	Table 8-7	4
2	Overall	2	Table 8-8	4

Table 8-7 Age Description and Score (n=1) CPF

Description	Score
0-14	4
15-29	3
30-44	2
45-49	1
55+	0

Table 8-8 Overall Description and Score (n=2) CPF

Description	Score
Good	4
Fair	3
Fair-Poor	2
Fair to Poor	2
Poor	0

8.3 Health Index Distribution

The total population of assets for this category is 7888. The Sample Size or total number of assets within the population that have sufficient data is 7864 (>99% of the population).

The installation year was assumed to the switchgear age.

The Health Indexing Result by Unit and Percentage are presented below:

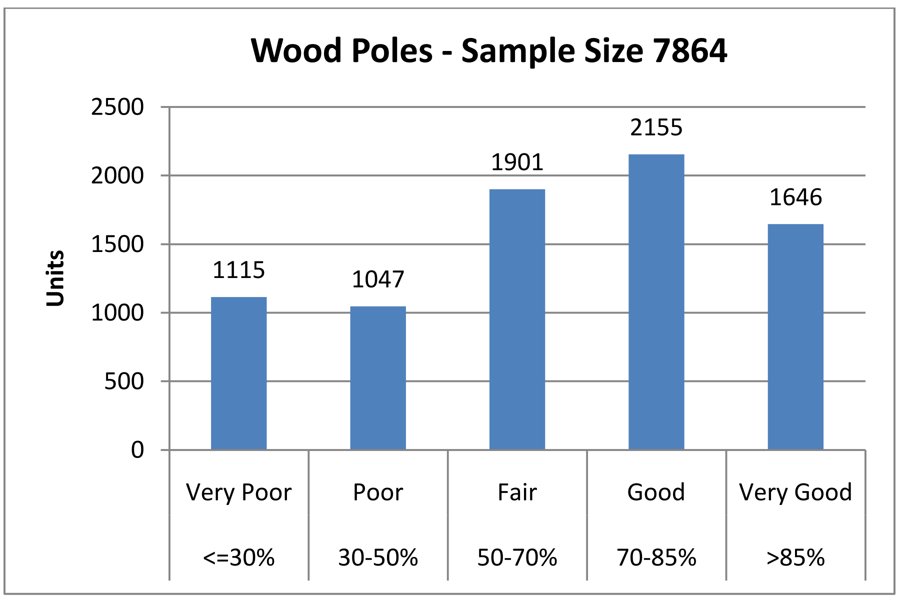


Figure 8-1 Health Index Distribution by Unit

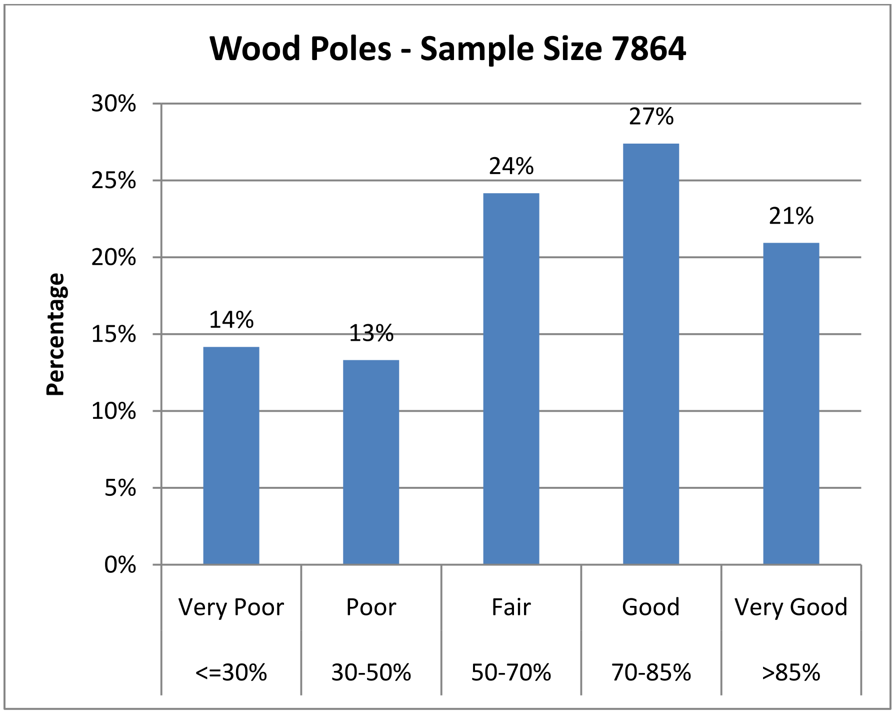


Figure 8-2 Health Index Distribution by Percentage

8.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 40 years the probability of failure is 10% and at age of 50 years the probability of failure is 90%.

8.4.1 Optimal Capital Replacement Plan

Figure 8-3 shows the number of poles that will need to be replaced over the next 20 years.

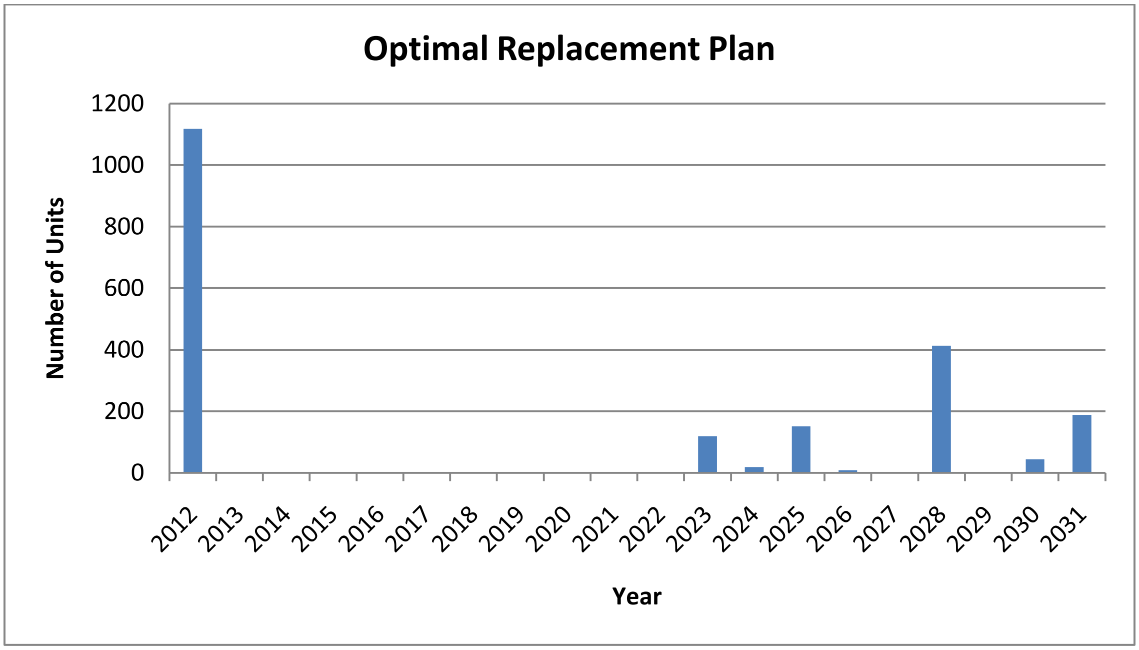


Figure 8-3 Optimal Replacement Plan

8.4.2 Levelized Capital Replacement Plan

For this asset category, the optimal replacement plan suggests replacing 444 poles next year. While this may be optimal based on the HI Distribution it may not be ideal financially.

Wood Poles are replaced **proactively**. The Levelized replacement plan allows for Poles that would optimally be replaced in one year to be replaced over a period of time (5 years). Figure 8-4 shows a Levelized capital replacement plan.

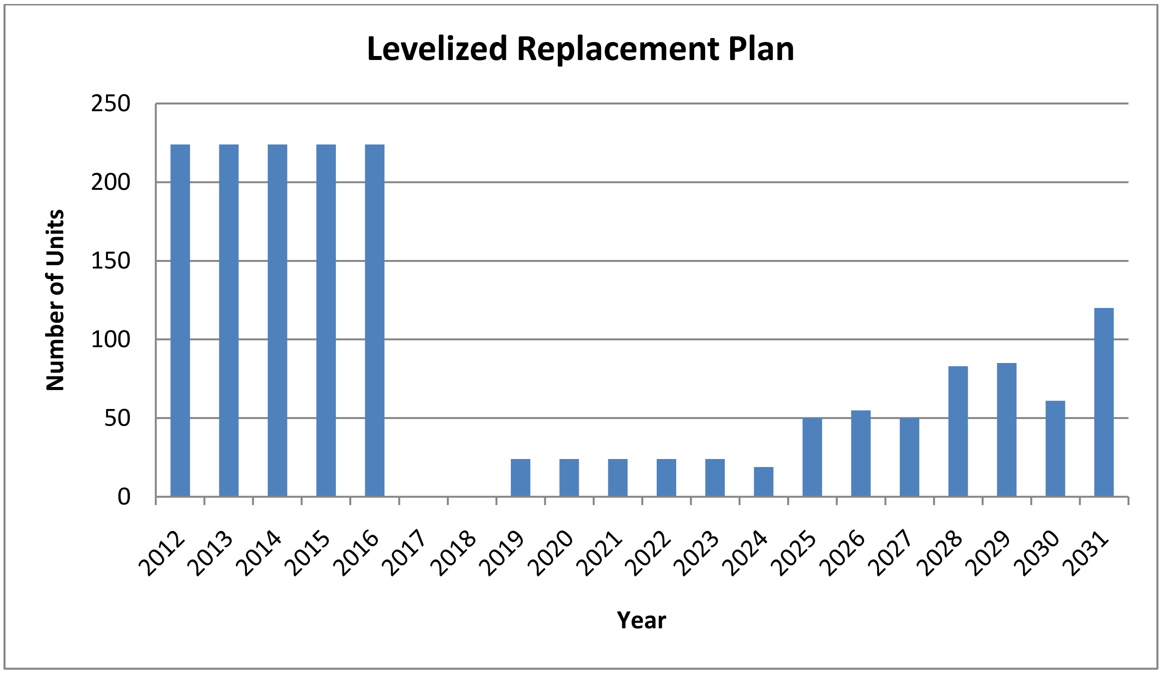


Figure 8-4 Levelized Replacement Plan

8.5 Data Gap Closures

There is no data gap for wood poles in this project.

9 CONCRETE POLES

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor and guys. The most important component with respect to useful life is the pole itself.

9.1 Degradation Mechanism

Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling.

Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in); however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete.

The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

9.2 Condition and Sub-Condition Parameters

Table 9-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	TABLE	$CPS_{m.max}$
1	Location	1	Table 9-2	4
2	Service Record	2	Table 9-4	4

9.2.1 Pole Location

Table 9-2 Location (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Roadway (Major/Minor)	1	Table 9-3	4

Table 9-3 Location Description and Score (n=1) CPF

Description	Score
Major Roadway	1

9.2.2 Pole Service Record

Table 9-4 Service Record (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	TABLE	$CPF_{n.max}$
1	Age	1	Table 9-5	4

Table 9-5 Age Description and Score (n=1) CPF

Description	Score
0-14	4
15-24	3
25-34	2
35-59	1
60+	0

9.3 Health Index Distribution

The total population of assets for this category is 676. The Sample Size or total number of assets within the population that have sufficient data is 676 (100% of the population).

The installation year was assumed to the pole age.

The Health Indexing Result by Unit and Percentage are presented below:

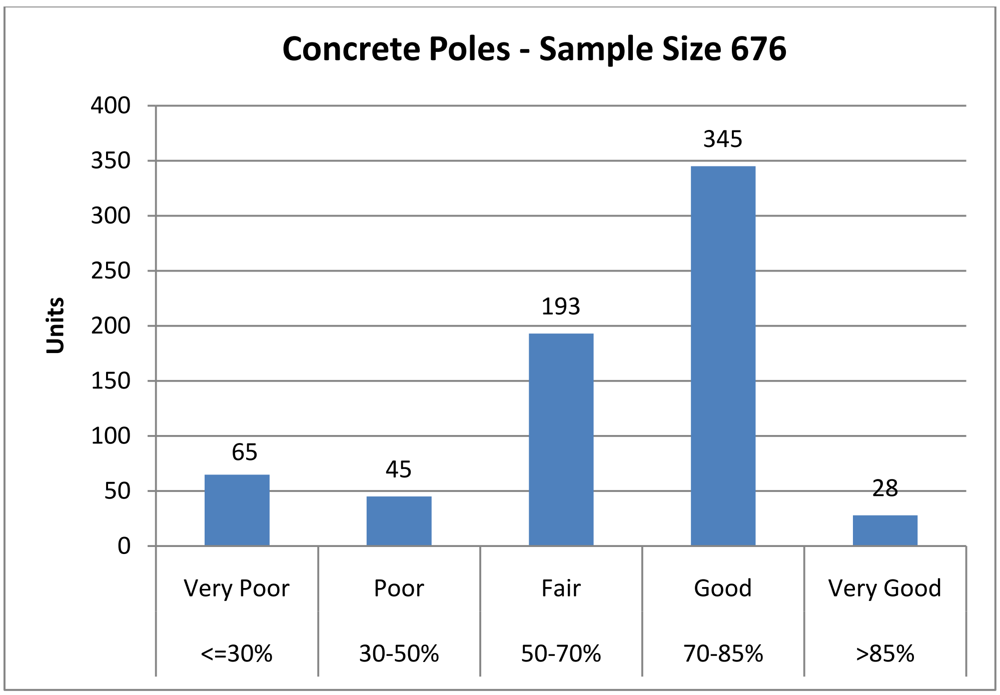


Figure 9-1 Health Index Distribution by Unit

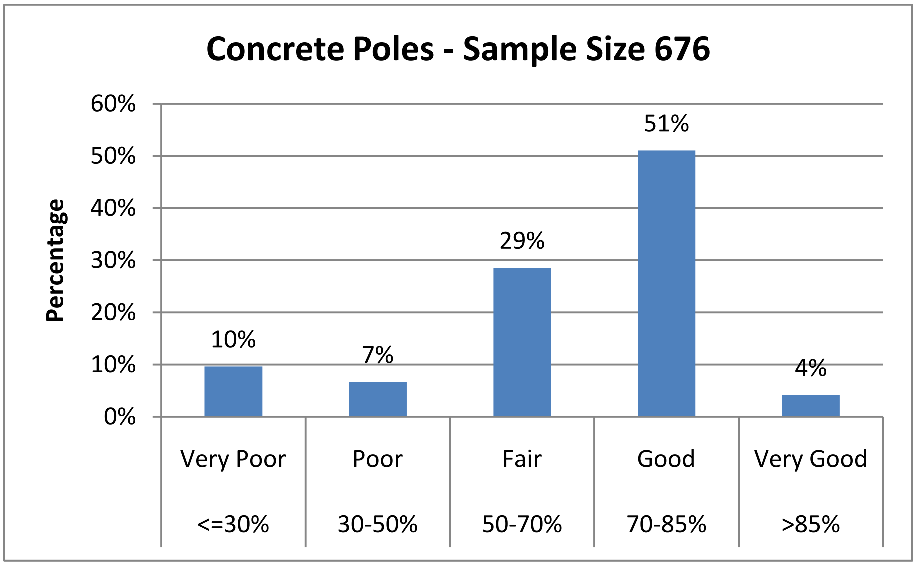


Figure 9-2 Health Index Distribution by Percentage

9.4 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 35 years the probability of failure is 10% and at age of 80 years the probability of failure is 90%.

9.4.1 Optimal Capital Replacement Plan

Figure 9-3 shows the number of poles that will need to be replaced over the next 20 years.

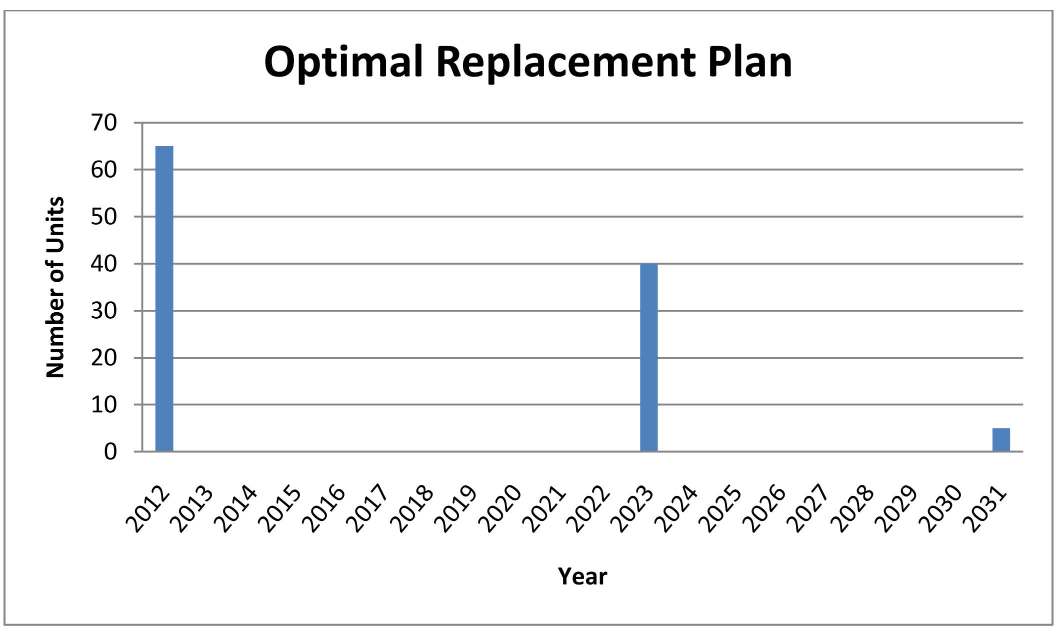


Figure 9-3 Optimal Replacement Plan

9.4.2 Levelized Capital Replacement Plan

For this asset category, the optimal replacement plan suggests replacing 65 poles next year. While this may be optimal based on the HI Distribution it may not be ideal financially.

Concrete Poles are replaced **proactively**. The Levelized replacement plan allows for Poles that would optimally be replaced in one year to be replaced over a period of time (5 years). Figure 9-4 shows a Levelized capital replacement plan.

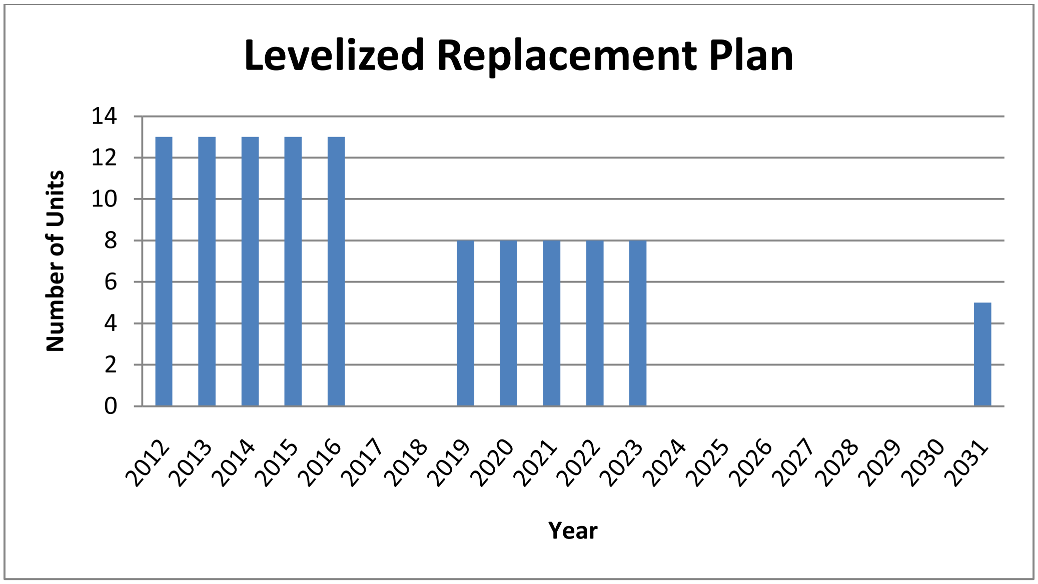


Figure 9-4 Levelized Replacement Plan

9.5 Data Gap Closures

There is no data gap for concrete poles in this project.

D CONCLUSIONS AND RECOMMENDATIONS

THIS PAGE HAS BEEN INTENTIONALLY LEFT BLANK

Conclusions and Recommendations

1. There were no data gaps for *Wood Poles* and *Concrete Poles*. Kinectrics recommends continuing to collect Data for those Assets.

2. There was also sufficient data for *Power Transformers* including Oil Testing and Oil Quality Inspections done on a regular basis to properly assess their condition. Kinectrics recommends continuing to collect Data for those Assets.

3. There was generally sufficient condition data available for *Pole Top Transformers*, *Pad Mounted Transformers, Submersible Transformers*, and *Vault Transformers*. Kinectrics recommends continuing to gather and record applicable data for those assets. In future asset condition assessments monthly loading should replace peak loading if it is available.

4. *Vault Transformers* require replacement costs to be included in the Capital Replacement Plan. Kinectrics recommends developing a replacement plan that includes this asset.

5. There was some data provided for *Overhead Switches* and *Pad Mounted Transformers*, such as age, operating practices (i.e., customers), peak loading and/or maintenance history. Kinectrics recommends gathering and recording detailed inspection data in order to derive a more accurate health index distribution, effective age and capital replacement plan.

6. There not sufficient data available for *Vaults* (Underground Distribution, Building and Manholes), *Underground Cables* and *Submersible Switchgear*. Kinectrics recommends that applicable inspection, fault history and maintenance information be gathered and recorded for these assets. They should be included in future asset condition assessments and condition-based capital plans.

GUELPH HYDRO ELECTRIC SYSTEMS INC.
2012 ASSET CONDITION ASSESSMENT

November 8, 2013

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

GUELPH HYDRO ELECTRIC SYSTEMS INC.
2012 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418526-RA-0001-R00

November 8, 2013

Prepared by:

Katrina Lotho, BE.Sc, B.Sc., P.Eng
Senior Engineer

LICENSED PROFESSIONAL ENGINEER
K. LOTHO
100157472
01/20/2014
PROVINCE OF ONTARIO

Mohsen Sheikholeslamzadeh
Engineer/Scientist

Reviewed and Approved by:

Yury Tsimberg, M.Eng, P.Eng
Director – Asset Management

Dated: 01/20/2014

To: Guelph Hydro Electric Systems Inc.

Revision History

Revision Number	Date	Comments	Approved
R00	November 8, 2013	Final Report	Yury Tsimberg

EXECUTIVE SUMMARY

Guelph Hydro Electric Systems Incorporated (GHESI) determined a need to perform a condition assessment of its key distribution assets. Such an undertaking would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, as well as facilitate the development of an asset management strategy.

In early 2013, GHESI selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on GHESI's key distribution assets as of the end of 2012.

The assets were divided into the following categories:

- Substation Transformers
- Circuit Breakers
- Pole Mounted Transformers
- Pad Mounted Transformers
- Submersible Transformers
- Vault Transformers
- Overhead Switches
    - LIS
    - SCADA Switches
- Pad Mounted Switches
    - Live Front SG
    - Solid Dielectric SG
    - Kabar
    - Multijunction
- Cables
    - Primary
    - Secondary
- Lines
    - 1 Phase Primary
    - 3 Phase Primary
    - Secondary
- Poles
    - Wood Poles
    - Concrete Poles
    - Composite Poles
- Vault
- Manholes

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution

- Developing a 20-year condition-based flagged for action plan
- Identifying and prioritizing the data gaps for each group

This Asset Condition Assessment Report summarizes the methodology used, outlines specific approaches used in this project, and presents the resulting findings and recommendations.

Asset Condition Assessment Methodology

The Asset Condition Assessment Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Flagged for Action Plan for each asset group.

<u>Health Index</u>

Health Indexing quantifies equipment condition based on numerous condition parameters 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, relative to a brand new asset, and is given in terms of percentage, with 100% representing an asset in brand new condition.

The condition data used in this study were obtained from GHESI and included the following:

- Asset Properties (e.g. age, location information)
- Test Results (e.g. Oil Quality, DGA)
- Inspection Records

A Health Index was calculated for each asset with sufficient condition data. As well, in order to provide an effective overview of the condition of each asset group, the Health Index Distribution for each asset category was determined.

<u>Condition-Based Flagged for Action Plan</u>

Once the Health Indices were calculated, a flagged for action plan based on asset condition was developed. The Condition-Based Flagged for Action Plan outlines the number of units that are expected to be replaced in the next 20 years. The numbers of units were estimated using either a *reactive* or *proactive* approach.

For assets with a relatively small consequence of failure, units are generally replaced or flagged for action *reactively* or on failure. The flagged for action plan for such an approach is based on the asset group's failure rate. This approach incorporates the possibility that assets may fail prematurely, prior to their expected typical end of lives.

In the *proactive* approach, units are assumed not to fail and are considered for action prior to failure. For asset groups that fall under this approach, a Risk Assessment study was conducted to determine the units eligible for replacement. This process establishes a relationship between an asset's Health Index and the corresponding probability of failure. Also involved was the quantification of asset criticality through the assignment of weights and scores to factors that impact the decision for replacement. The combination of criticality and probability of failure determines risk and flagged for action priority for that unit.

Health Index Results

Table 1 shows a summary of the Health Index results. The Health Index distribution, average Health Index, population and sample size each asset category is given.

Civil structures, namely vaults and manholes, were found on average to be in the worst condition. Approximately 39% of manholes and 27% of vaults are classified as poor or very poor. It should be noted, however, that the vaults and manholes inspected and assessed in this study were suspect units or in suspect locations. As such, they may generally be in worse condition and not representative of the entire population.

Approximately 9% of pole mounted transformers are in poor or very poor condition. It is also worth noting that 4% of both the wood pole and SCADA populations are classified as poor or very poor.

Table 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%)
Substation Transformers		4	4	94%	0%	0%	0%	0%	100%
Circuit Breakers		20	20	100%	0%	0%	0%	0%	100%
Pole Mounted Transformers		1791	1789	81%	< 1%	8%	20%	26%	44%
Pad Mounted Transformers		3722	3722	88%	< 1%	1%	11%	24%	64%
Submersible Transformers		42	42	88%	0%	2%	14%	17%	67%
Vault Transformers		82	82	90%	1%	0%	2%	17%	79%
Overhead Switches	LIS	372	372	86%	0%	0%	< 1%	48%	52%
	SCADA	85	85	78%	0%	4%	26%	38%	33%
Pad Mounted Switches	Live Front SG	89	89	90%	0%	0%	7%	8%	85%
	Solid Dielectric SG	6	6	100%	0%	0%	0%	0%	100%
	Kabar	60	60	93%	0%	2%	7%	3%	88%
	Multijunction	34	34	86%	0%	3%	12%	21%	65%
Cables	Primary	663	663	96%	< 1%	< 1%	6%	4%	90%
	Secondary	1074	1074	97%	< 1%	< 1%	< 1%	3%	96%
Lines	1 Phase Primary	101	101	99%	0%	0%	0%	< 1%	100%
	3 Phase Primary	326	326	100%	0%	0%	0%	0%	100%
	Secondary	471	463	97%	0%	0%	< 1%	< 1%	100%
Poles	Wood Poles	10426	10426	80%	< 1%	4%	16%	36%	44%
	Concrete Poles	897	896	96%	0%	0%	0%	22%	78%
	Composite Poles	191	190	99%	0%	0%	0%	< 1%	99%
Vault		560	66	58%	3%	24%	44%	24%	5%
Manholes		247	33	51%	21%	18%	36%	12%	12%

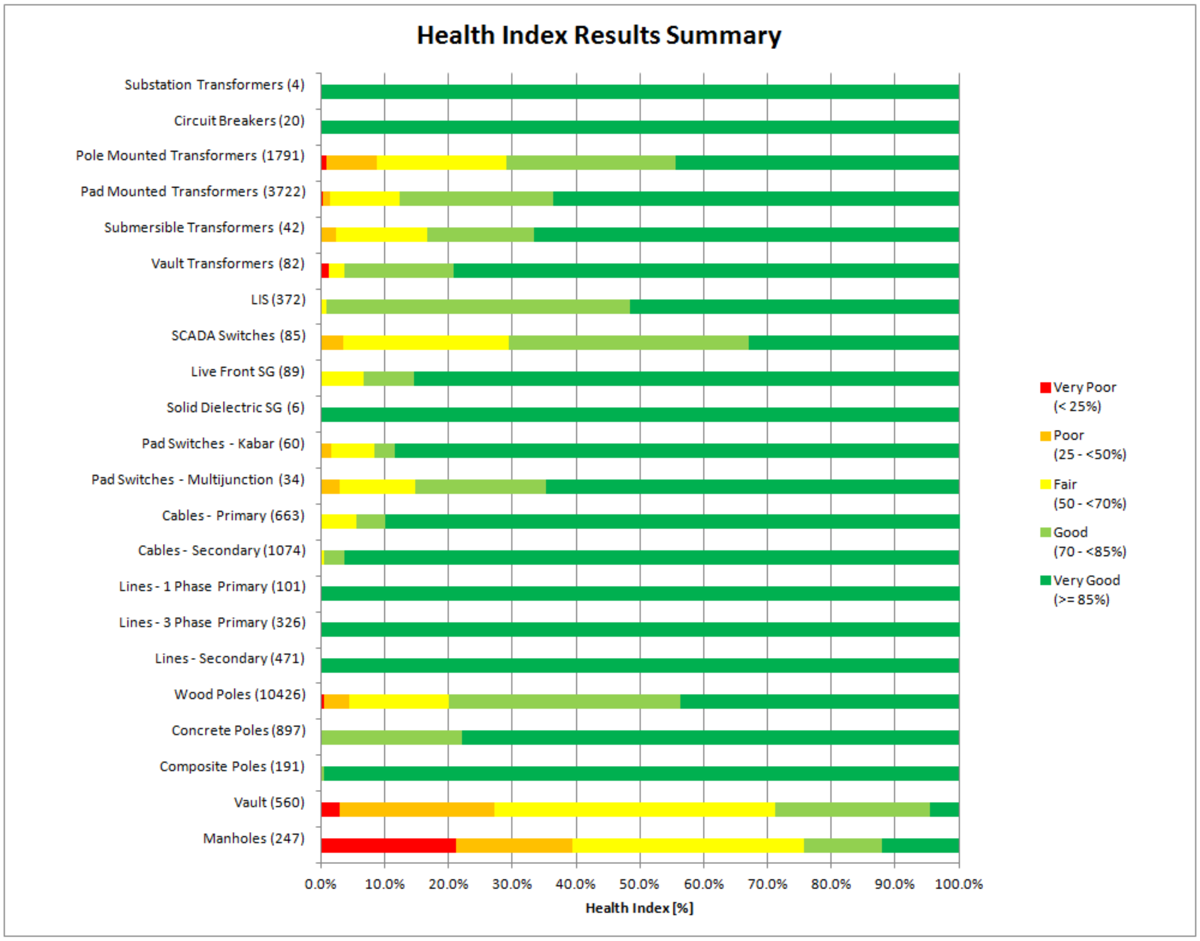


Figure 1 Graphical Health Index Summary (Population in Parenthesis)

Condition Based Flagged for Action Plan

Table 2 shows the first year optimal replacement plan and action strategy for each category.

GHESI's most significant asset group requiring action, in terms of number of units, is wood poles. Almost 200 poles are expected to be flagged for action in the first year. Also noteworthy are pole mounted transformers and pad mounted transformers, where 61 and 44 respectively are flagged. In addition, 8 vaults and 6 manholes need to be addressed in the first year.

Table 2 Year 1 Optimal Condition-Based Flagged for Action Plan and Action Strategy

Asset Category		Condition-Based Replacement Plan for Year 1		Action Strategy
		Number of Units	Percentage of Population	
Substation Transformers		0	0.0%	proactive
Circuit Breakers		0	0.0%	proactive
Pole Mounted Transformers		61	3.4%	reactive
Pad Mounted Transformers		44	1.2%	reactive
Submersible Transformers		1	2.4%	reactive
Vault Transformers		0	0.0%	reactive
Overhead Switches	LIS	0	0.0%	reactive
	SCADA	1	1.2%	reactive
Pad Mounted Switches	Live Front SG	0	0.0%	reactive
	Solid Dielectric SG	0	0.0%	reactive
	Kabar	0	0.0%	reactive
	Multijunction	0	0.0%	reactive
Cables*	Primary	4	0.6%	reactive
	Secondary	4	0.4%	reactive
Lines*	1 Phase Primary	0	0.0%	reactive
	3 Phase Primary	0	0.0%	reactive
	Secondary	1	0.2%	reactive
Poles	Wood Poles	199	1.9%	proactive
	Concrete Poles	0	0.0%	proactive
	Composite Poles	0	0.0%	proactive
Vault		8	1.4%	proactive
Manholes		6	2.4%	proactive

*data in terms of conductor-km

Figure 1 and Figure 2 show the 20 year the optimal and levelized condition-based flagged for action plans.

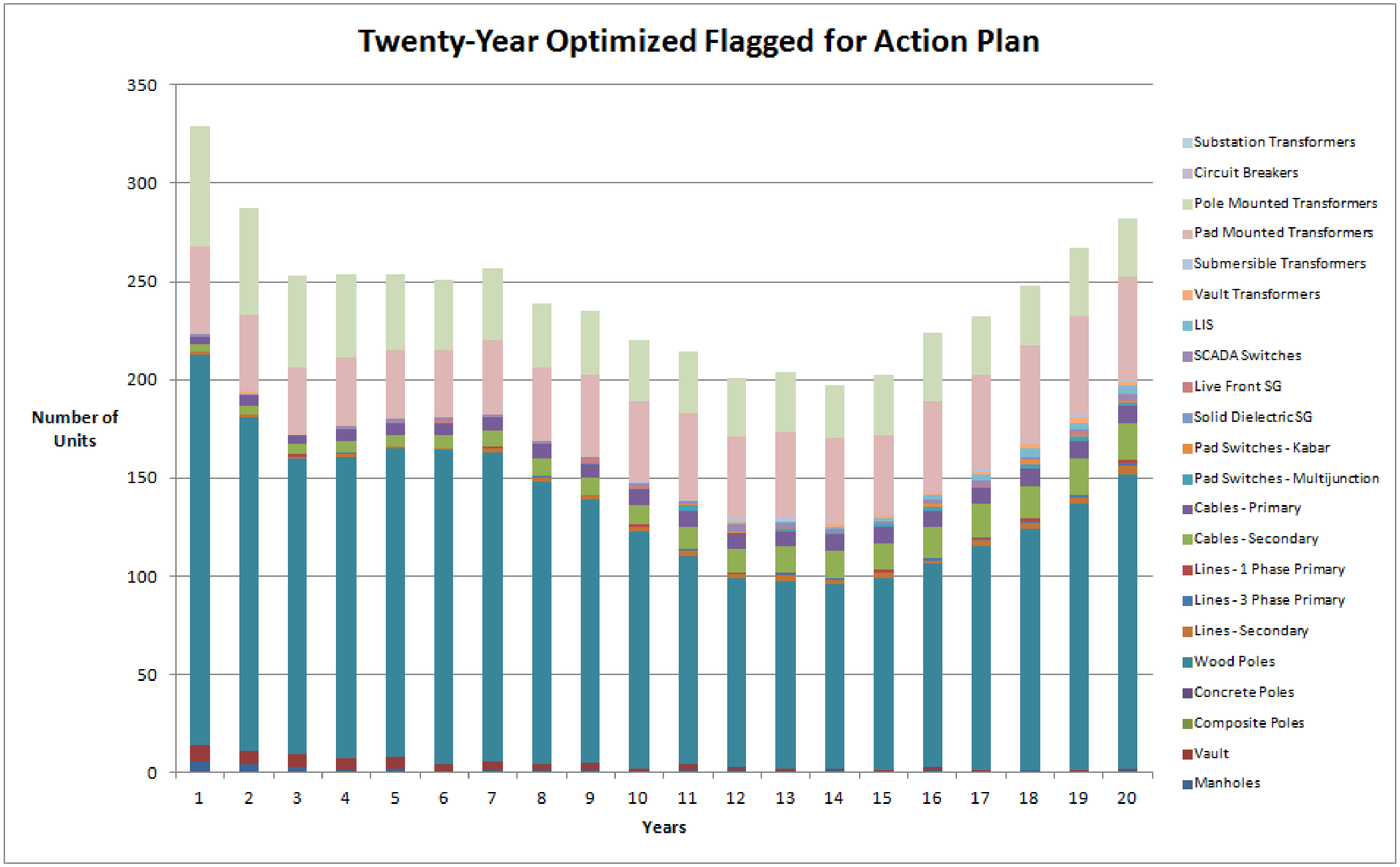


Figure 2 Graphical Twenty-Year Optimal Flagged for Action Plan

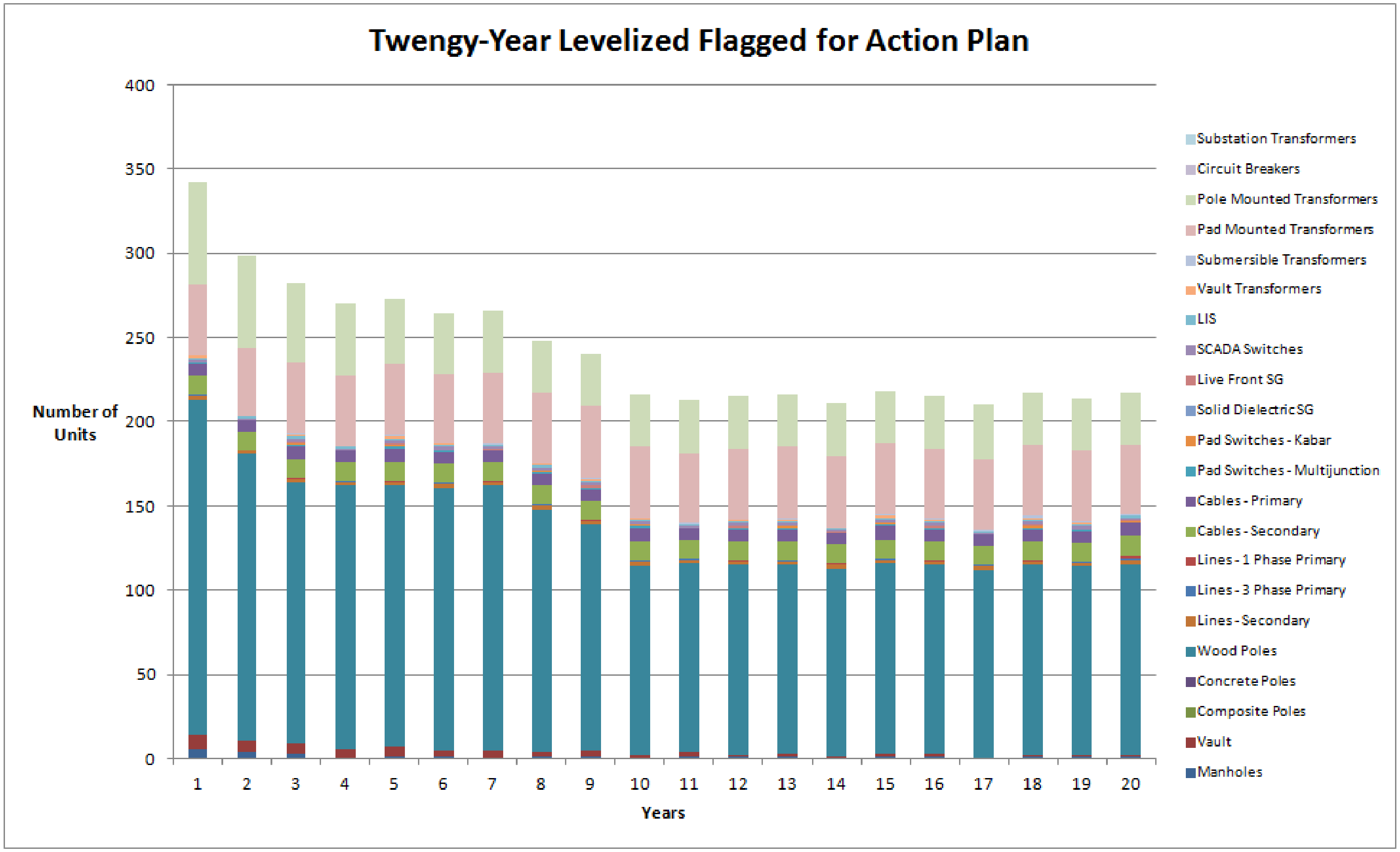


Figure 3 Graphical Twenty-Year Levelized Flagged for Action Plan

Data Assessment Results

The following asset categories had fairly high data availability indicators: substation transformers, vault transformers, live front pad mounted switchgear, and wood poles. Good condition data was available for most of the units in these asset categories.

Although pad mounted transformers, concrete and composite poles are being inspected, inspection records were only partially available for these asset categories. Circuit breakers, Kabars and multijunction, lines and cables had only age available.

Conclusions and Recommendations

1. An Asset Condition Assessment was conducted for GHESI's key distribution assets, namely substation transformers, circuit breakers, distribution transformers, overhead switches, pad mounted switches, cables, lines, poles, vaults, and manholes.

2. Underground civil structures were found to be, on average, in the worst condition. Approximately 39% of manholes and 27% of vaults are in poor or very poor condition.

   It should be noted, however, that the vaults and manholes inspected and assessed in this study were suspect units or in suspect locations. As such, they may generally be in worse condition and not representative of the vault and manhole populations.

   It is recommended that inspections be conducted for more representative samples of the vault and manhole populations. A more random and representative sample pool will allow the Health Index results to be extrapolated over the populations.

3. Other asset categories worth noting are pole mounted transformers, wood poles, and SCADA switches. Approximately 9% of pole mounted transformers, 4% of wood poles, and 4% of SCADA switches are in poor or very poor condition.

4. Wood poles was identified as having the biggest quantity of units flagged for action in the first year. Nearly 200 poles (1.9% of the population) require action in the first year.

   It is worth noting that 61 pole mounted transformers (3.4% of the population) and 44 pad mounted transformers (1.2% of the population) are flagged for action in the first year.

   Eight (8) vaults (1.4% of the population) and 6 manholes (2.4% of the population) also need to be addressed.

5. 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 GHESI's asset management strategy.

6. Substation transformers, vault transformers, live front pad mounted switchgear, and wood poles had good condition data available for most units. As such, these asset categories had fairly high data availability indicators.

   Circuit breakers, Kabars and multijunction, lines and cables had only age data available.

   Although pad mounted transformers, concrete and composite poles are being inspected, inspection records were only partially available for these asset categories. It is recommended that inspection data be collected for the remainder of the units.

7. The data gaps for all asset categories, if applicable, were identified. It is recommended that efforts be made to close the data gaps in a prioritized manner.

This page is intentionally left blank.

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

This page is intentionally left blank.

I INTRODUCTION

This page is intentionally left blank.

I Introduction

Guelph Hydro Electric Systems Inc. (GHESI) is a local distribution company that provides electricity to over 50,000 residential, commercial, and industrial customers in Guelph and Rockwood, Ontario.

Guelph Municipal Holdings, which in turn is 100% owned by the City of Guelph, wholly owns GHESI. Activities, performance standards, and rates are regulated by the Ontario Energy Board.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

In early 2013, GHESI selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on GHESI's key distribution assets.

The Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Scope of Work

The assets in this study are categorized as follows:

- Substation Transformers
- Circuit Breakers
- Pole Mounted Transformers
- Pad Mounted Transformers
- Submersible Transformers
- Vault Transformers
- Overhead Switches
    - LIS
    - SCADA Switches
- Pad Mounted Switches
    - Live Front SG
    - Solid Dielectric SG
    - Kabar
    - Multijunction
- Cables
    - Primary
    - Secondary
- Lines
    - 1 Phase Primary
    - 3 Phase Primary
    - Secondary

- Poles
    - Wood Poles
    - Concrete Poles
    - Composite Poles
- Vault
- Manholes

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based replacement plan
- Identifying and prioritizing the data gaps for each group

I.2 **Deliverables**

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

- Description of methodology for condition assessment of replacement plan (Section II)
- Description of the data assessment procedure (Section III)
- For each asset category the following are included (VI Appendix A: Results and Findings for Each Asset Category: Section 1 – Section 22):
    - Age distribution
    - Health Index formulation
    - Health Index distribution
    - Condition-based Replacement Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis

II ASSET CONDITION ASSESSMENT METHODOLOGY

This page is intentionally left blank.

II Asset Condition Assessment Methodology

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Replacement Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

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 "Colour".

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

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

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

Equation 1

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (WCPF_n)}$$

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for 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*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.

II.1.1 Health Index Example

Consider the asset class "Oil Circuit Breaker". The condition and sub-condition parameters, as well as their weights are shown on Table II-3.

Table II-3 Oil Circuit Breaker Condition and Sub-Condition Parameters

Health Index Formula for Oil Circuit Breakers			
Condition Parameters		**Sub-Condition Parameters**	
Name	**Weights (WCP)**	**Name**	**Weights (WCPF)**
Operating Mechanism	14	Lubrication	9
		Linkage	5
		Cabinet	2
Contact Performance	7	Closing Time	1
		Trip Time	3
		Contact Resistance	1
		Arcing Contact	1
Arc Extinction	9	Moisture	8
		Leakage	1
		Tank	2
		Oil Level	1
		Oil Quality	8
Insulation	2	Insulation	1
Service Record	5	Operating Counter	2
		Loading	2
		Age	1

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

Scores are determined using *condition criteria*. The criterion defines the score of a particular parameter. Consider, for example, the age criteria given on Table II-4. An asset that is 35 years old will receive a score of "2" for "Age".

Table II-4 Age Criteria

Parameter Score	Condition Description
4	0-19
3	20-29
2	30-39
1	40-44
0	45+

Table II-5 shows a sample Health Index evaluation for a particular oil breaker. The sub-condition parameter scores (CPFs) shown are assumed values between 0 through 4.

The Condition Parameter Score (CPS) is evaluated as per Equation 2. The Health Index (HI) is calculated as per Equation 1. As no de-rating factors are defined, there is no multiplier for the final Health Index.

Table II-5 Sample Health Index Calculation

Condition Parameters	Operating Mechanism			Contact Performance			Arc Extinction			Insulation			Service Record		
Sub-Condition Parameters Scores (CPF) Weights (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)
	Lubrication	4	9	Closing Time	2	1	Moisture	4	8	Insulation	4	1	Operating Counter	3	2
	Linkage	2	5	Trip Time	3	3	Leakage	3	1				Loading	4	2
	Cabinet	3	2	Contact Resistance	2	1	Tank	3	2				Age	3	1
				Arcing Contact	3	1	Oil Level	2	1						
							Oil Quality	3	8						
Condition Parameter Score (CPS)	Operating Mechanism CPS (4*9 + 2*5 + 3*2) / (9+5+2) = 3.25			Contact Performance CPS (2*1 + 3*3 + 2*1 + 3*1) / (1+3+1+1) = 2.67			Arc Extinction CPS (4*8 + 3*1 + 3*2 + 2*1 + 3*8) / (8+1+2+1+8) = 3.35			Insulation CPS (4*1) / (1) = 4			Service Record CPS (3*2 + 4*2 + 3*1) / (2+2+1) = 3.4		
Weights (WCP)	*Weight = 14*			*Weight = 7*			*Weight =9*			*Weight = 2*			*Weight = 5*		
Health Index (HI)	**HI** = (3.25*14 + 2.67*7 + 3.35*9 + 4*2 + 3.4*5) / ((14 + 7 + 9 + 2 + 5)*4) = **80.6%**														

II.1.2 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 Station Transformers, the Health Index of each individual unit is given.

II.2 **Condition-Based Flagged for Action Methodology**

The Condition-Based Flagged for Action plan outlines the number of units that are projected to be replaced in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the reactive 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 the best model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

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' expertise in failure rate study of multiple power system asset groups, the following variation of the failure rate formula is adopted:

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

Equation 4

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 probability of failure function is therefore:

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

Equation 5

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 location and steepness of 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 25 and 65 the asset has cumulative probabilities of failure of 10% and 99% respectively. It follows that when using Equation 5, α and β are calculated as 74 and 0.093 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{\alpha\beta})/\beta} = 1 - e^{-(e^{0.093(t-74)} - e^{-6.882})/0.093}$$

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

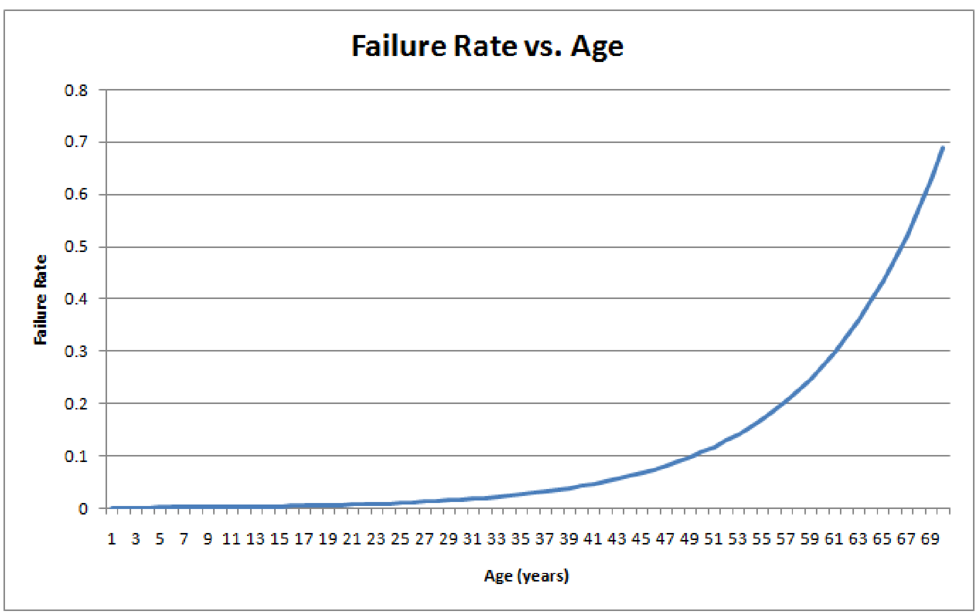


Figure II-4 Failure Rate vs. Age

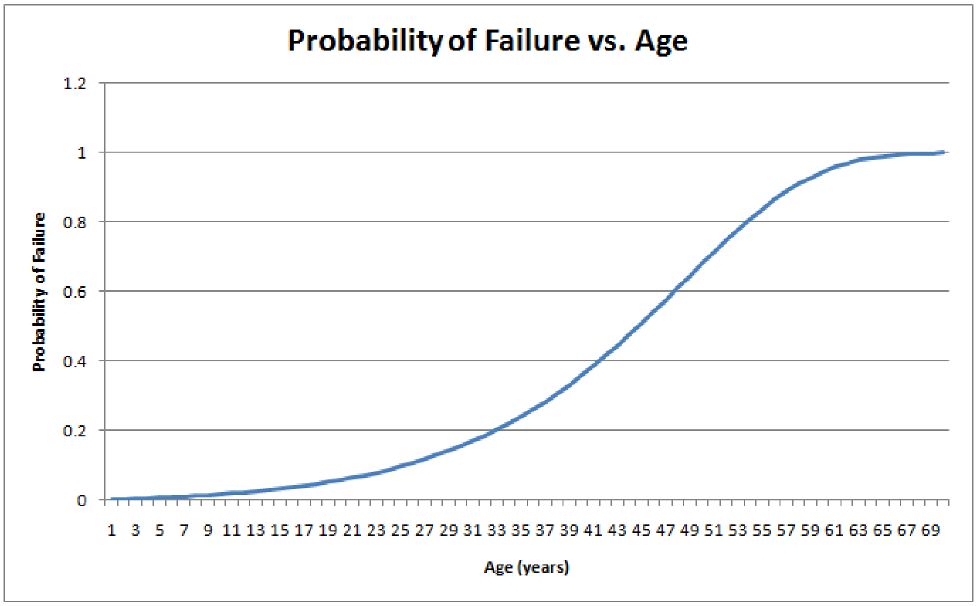


Figure II-5 Probability of Failure vs. Age

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

Because their 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:

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

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

An example of such an 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, as opposed to the chronological age of the asset.

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

For certain asset classes, the consequence of asset failure is significant, and, as such, these assets are proactively replaced prior to failure. The proactive flagged for action 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

Failure of an asset occurs when the stress to which an asset is exposed exceeds its strength. Assuming that stress is not constant, and that stress is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure. This is illustrated in the figure below. A vertical line represents condition or strength (Health Index) and the area under the curve to the right of the Health Index line represents the probability of failure.

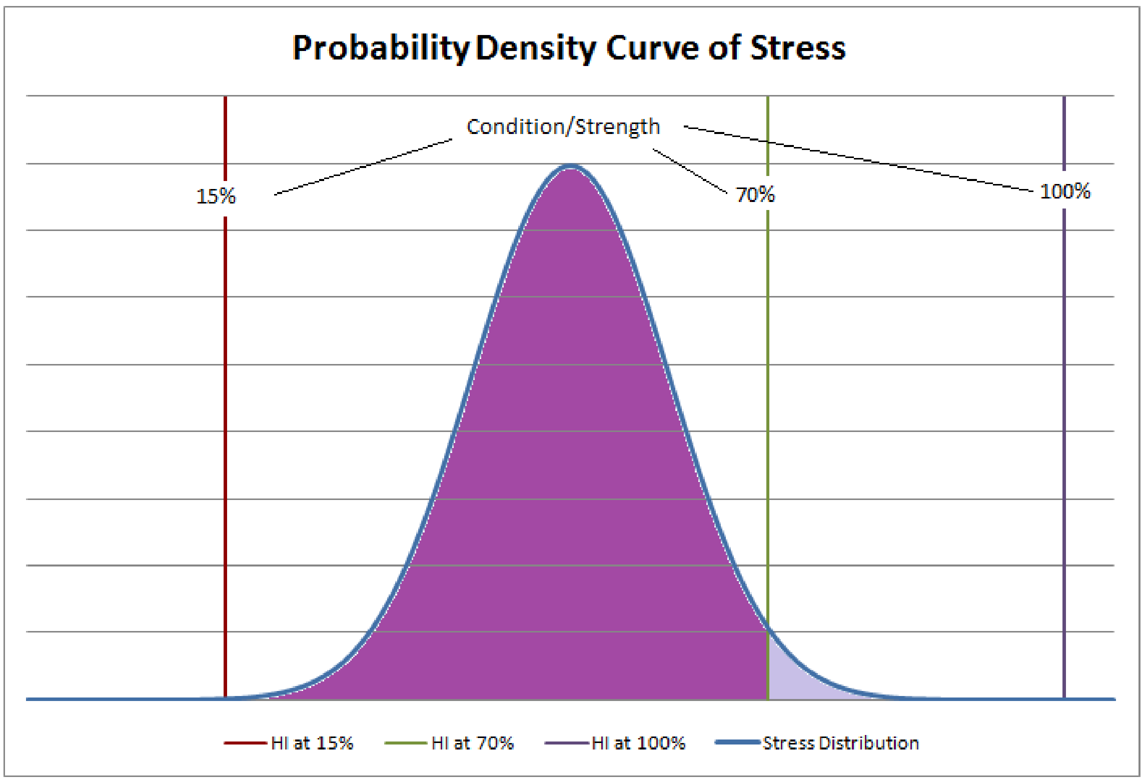


Figure II-6 Stress Curve

Two points of Health Index and probability of failure are needed to generate the probability of failure at other Health Index values. A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 15% represents the asset's end of life. The 100% and 15% conditions are plotted on the stress curve by finding the points at which the areas under the stress curve are equal to $P_{f\ 100\%}$(age at 100% Health Index) and $P_{f\ 15\%} = P_f$(age at 15% Health Index). By moving the vertical line left from 100% to 15%, the probabilities of failure for other Health Indices can be found.

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

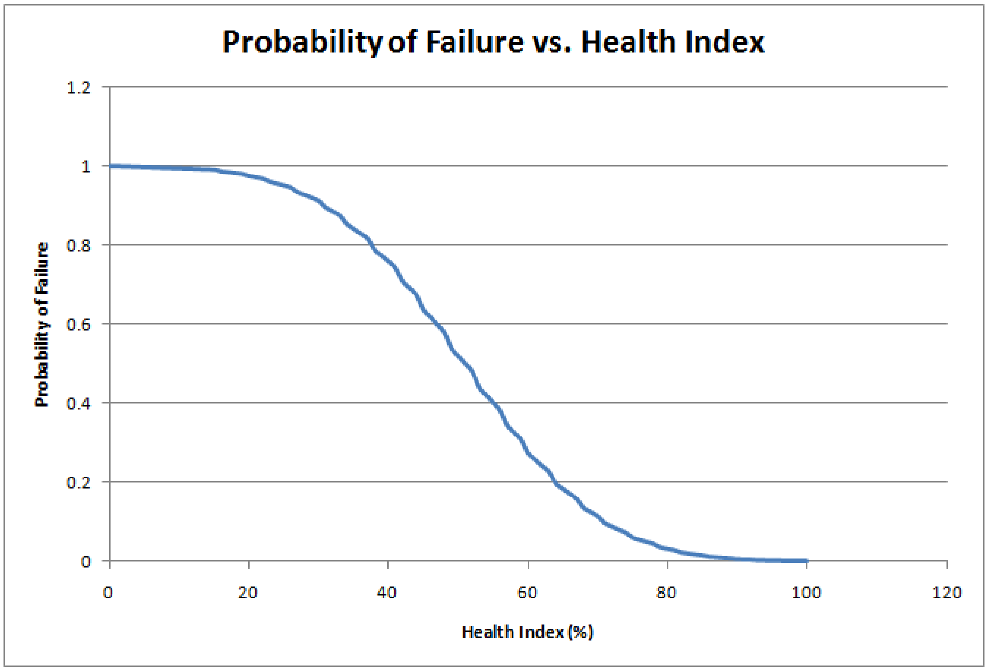


Figure II-7 Probability of Failure vs. Health Index

Relating Health Index to Effective Age

Once the relationship between probability of failure and Health Index has been found, the "effective age" of an asset can be determined. The "effective age" is different from chronological age in that it is based on the asset's condition and the stresses that are applied to the asset.

The probability of failure associated with a specific Health Index can be found using the Probability of Failure vs. Health Index (Figure II-7) and Probability of Failure vs. Age (Figure II-5). The probability of failure at a particular Health Index can be found from Figure II-7. The same probability of failure is located on Figure II-5, and the effective age is on the horizontal axis of Figure II-5. See example on the figure below where a Health Index of 60% corresponds to an effective age of 35 years.

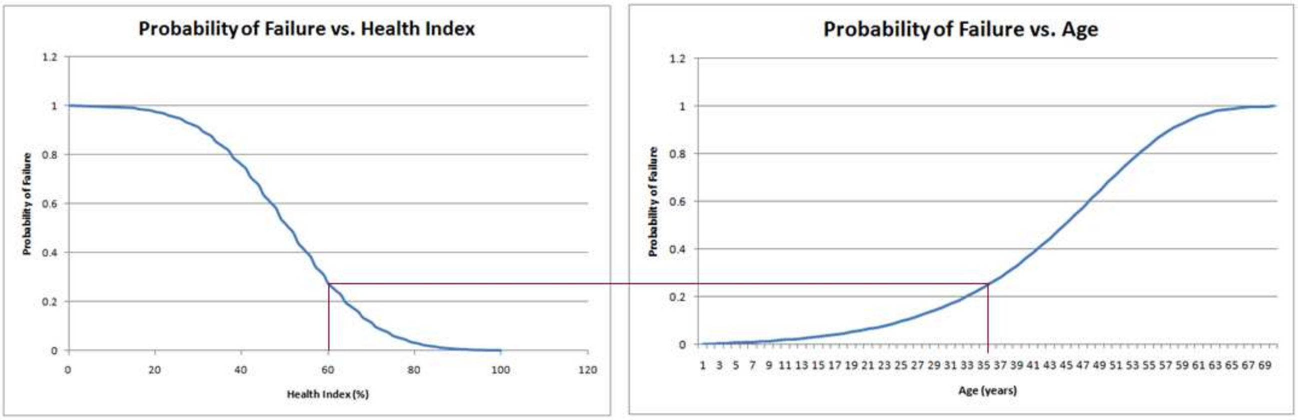


Figure II-8 Effective Age

Condition-Based Flagged for Action Plan

In order to develop an 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.

It is assumed in this study that each asset group has a base criticality value, Criticality_{min}. The individual units in the asset group are assigned Criticalities that are multiples of Criticality_{min}. A unit becomes a candidate for action when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1.

In the example shown below, Asset 1 and Asset 2 are candidates for replacement.

Table II-6 Sample Flagged for Action Ranking

Asset Name	Age	Health Index (HI)	Consequence of Failure (Criticality)	Probability of Failure (POF) Corresponding to HI	Risk (POF*Criticality)	Replacement Ranking
Asset 1	41	30.00%	2	78.20%	1.564	1
Asset 2	29	30.00%	1.5	78.20%	1.173	2
Asset 3	37	30.00%	1.25	78.20%	0.9775	3
Asset 4	42	50.00%	2	12.80%	0.256	4
Asset 5	18	50.00%	1.5	12.80%	0.192	5
Asset 6	20	50.00%	1.25	12.80%	0.16	6

II.3 Optimal and Levelized Flagged for Action Plans

The optimal Condition-Based Flagged for Action plan shows the optimal time of replacement, namely when the risk cost is equal to one for proactively replaced assets and the time of expected failure for run to failure assets. As it may not always be feasible to act as per the optimal plan, a "levelized" or smoother action plan may allow a utility to better manage capital investments.

The levelized action plan for proactively replaced assets allows for investments to be accelerated or deferred for a limited number of years. The levelized plan for reactively replaced assets suggests replacing assets prior to their time of expected failure.

III DATA ASSESSMENT

This page is intentionally left blank.

III Data Assessment

The condition data used in this study were obtained from GHESI and included the following:

- Asset Properties (e.g. age, location information)
- Test Results (e.g. Oil Quality, DGA)
- Inspection Records

There are two components that assess the availability and quality of data used in this study: Data Availability Indicator (DAI) and Data Gap.

III.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:

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

Equation 6

where

$$DAI_{CPm} = \frac{\sum_{n=1}^{\forall n} (\beta_n \times WCF_n)}{\sum_{n=1}^{\forall n} (WCF_n)}$$

Equation 7

DAI	Overall Data Availability Indicator for an asset with m Condition Parameters
DAI_{CPm}	Data Availability Indicator for Condition Parameter
WCP_m	Weight of Condition Parameter m
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

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

<table>
<tr><th colspan="2">Condition Parameter</th><th rowspan="2">Condition Parameter Weight (WCP)</th><th colspan="2">Sub-Condition Parameter</th><th rowspan="2">Sub-Condition Parameter Weight (WCF)</th><th rowspan="2">Data Available? (β = 1 if available; 0 if not)</th></tr>
<tr><th>m</th><th>Name</th><th>n</th><th>Name</th></tr>
<tr><td>1</td><td>A</td><td>1</td><td>1</td><td>A_1</td><td>1</td><td>1</td></tr>
<tr><td rowspan="3">2</td><td rowspan="3">B</td><td rowspan="3">2</td><td>1</td><td>B_1</td><td>2</td><td>1</td></tr>
<tr><td>2</td><td>B_2</td><td>4</td><td>1</td></tr>
<tr><td>3</td><td>B_3</td><td>5</td><td>0</td></tr>
<tr><td>3</td><td>C</td><td>3</td><td>1</td><td>C_1</td><td>1</td><td>0</td></tr>
</table>

The Data Availability Indicator is calculated as follows:

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

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

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.

III.2 Data Gap

The Health Index formulations developed and used in this study are based solely on GHESI's available data. There are additional parameters or tests that GHESI may not collect but nonetheless 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 formulations.

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

This page is intentionally left blank.

IV RESULTS

This page is intentionally left blank.

IV Results

This section summarizes the findings of this study.

Health Index Results

A summary of the Health Index evaluation results is shown in Table IV-1. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. For each group the Health Index Distribution and average Health Index are shown. Also given is the average age of each group.

It can be seen from the results that manholes and vaults are, on average, in the worst condition. The average Health Index for these asset categories are 51% and 58% respectively. Approximately 39% of manholes are in poor or very poor condition; around 27% of vaults are in poor or very poor condition. It should be noted, however, that the vaults and manholes in this study's sample pool were inspected and subsequently assessed because they were suspect units or in areas that made them more prone to degradation. The samples are not likely to be representative of the entire vault and manhole populations. It is probable that the remainders of the vault and manhole populations are, on average, in better condition than the samples.

Also of concern are pole mounted transformers. Although the average HI of pole mounted transformers is 81%, 9% of the assets are in poor or very poor condition. It is also worth noting that 4% of both the wood pole and SCADA populations are in poor or very poor condition.

Condition Based Flagged for Action Plan

The condition-based action plan for the first year and the flagged for action strategy is shown for each asset group in Table IV-2.

Table IV-3 and Table IV-4 show the 20 year optimized and levelized action plan. The same information is shown graphically on

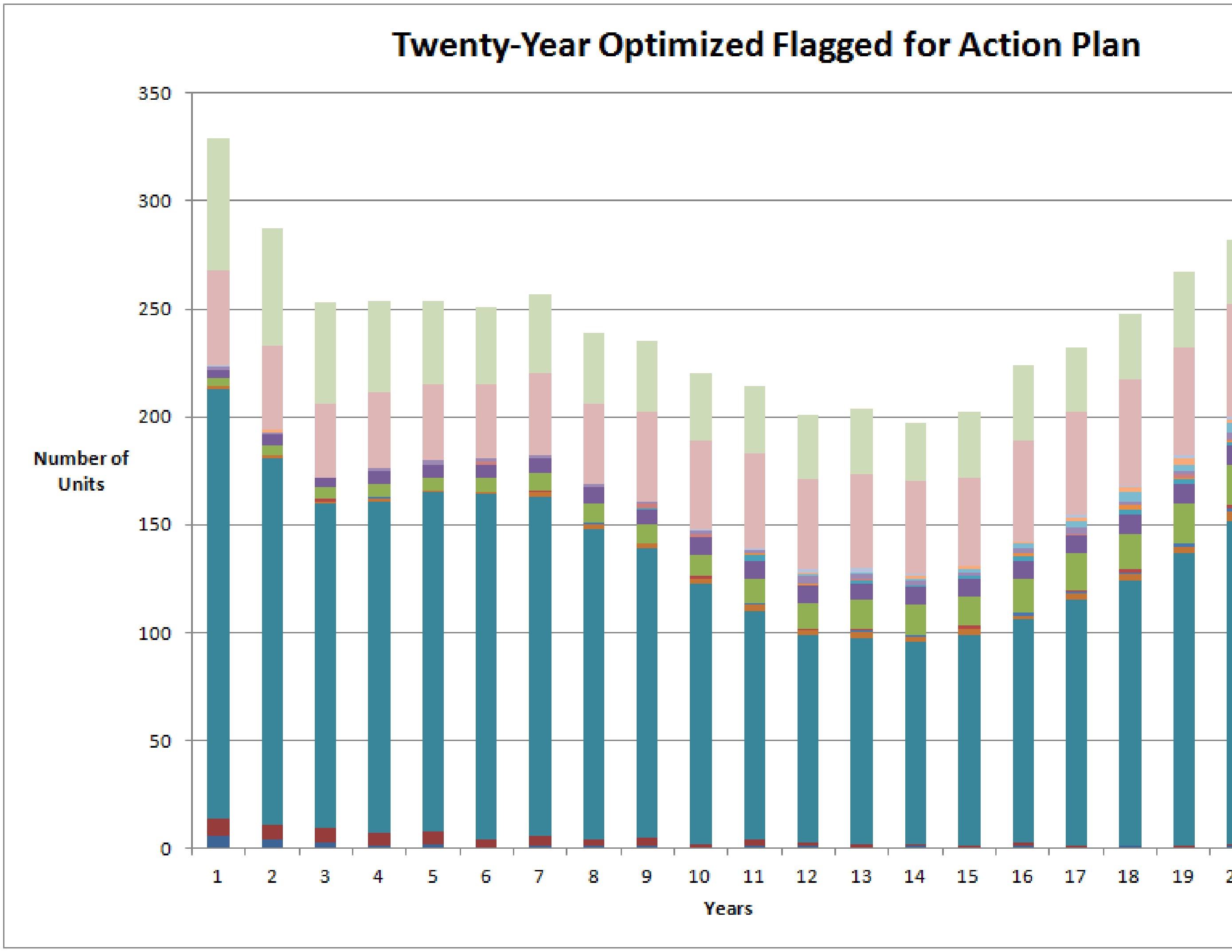


Figure IV-2 and Figure IV-3.

It is important to note that the 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 for replacement. While the Condition-Based Flagged for Action Plan can be used as a guide or input to GHESI's asset management strategy, it is not expected that it be followed directly or as the final deciding factor in sustainment and capital decisions. There are numerous other factors and considerations that will influence GHESI's asset management decisions.

The most significant asset, in terms of quantities flagged for action, is wood poles. Nearly 200 wood poles are flagged for action in the first year; this represents 1.9% of the population. Also of significance is that 61 pole mounted transformers (3.4% of the population) and 44 pad mounted transformers (1.2% of the population) are flagged for action in the first year. In addition, 8 vaults (1.4% of the population) and 6 manholes (2.4% of the population) need to be addressed.

Table IV-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Substation Transformers		4	4	94%	0%	0%	0%	0%	100%	7
Circuit Breakers		20	20	100%	0%	0%	0%	0%	100%	3
Pole Mounted Transformers		1791	1789	81%	< 1%	8%	20%	26%	44%	20
Pad Mounted Transformers		3722	3722	88%	< 1%	1%	11%	24%	64%	14
Submersible Transformers		42	42	88%	0%	2%	14%	17%	67%	14
Vault Transformers		82	82	90%	1%	0%	2%	17%	79%	23
Overhead Switches	LIS	372	372	86%	0%	0%	< 1%	48%	52%	13
	SCADA	85	85	78%	0%	4%	26%	38%	33%	8
Pad Mounted Switches	Live Front SG	89	89	90%	0%	0%	7%	8%	85%	12
	Solid Dielectric SG	6	6	100%	0%	0%	0%	0%	100%	1
	Kabar	60	60	93%	0%	2%	7%	3%	88%	14
	Multijunction	34	34	86%	0%	3%	12%	21%	65%	23
Cables	Primary	663	663	96%	< 1%	< 1%	6%	4%	90%	16
	Secondary	1074	1074	97%	< 1%	< 1%	< 1%	3%	96%	17
Lines	1 Phase Primary	101	101	99%	0%	0%	0%	< 1%	100%	27
	3 Phase Primary	326	326	100%	0%	0%	0%	0%	100%	18
	Secondary	471	463	97%	0%	0%	< 1%	< 1%	100%	27
Poles	Wood Poles	10426	10426	80%	< 1%	4%	16%	36%	44%	34
	Concrete Poles	897	896	96%	0%	0%	0%	22%	78%	16
	Composite Poles	191	190	99%	0%	0%	0%	< 1%	99%	4
Vault		560	66	58%	3%	24%	44%	24%	5%	23
Manholes		247	33	51%	21%	18%	36%	12%	12%	18

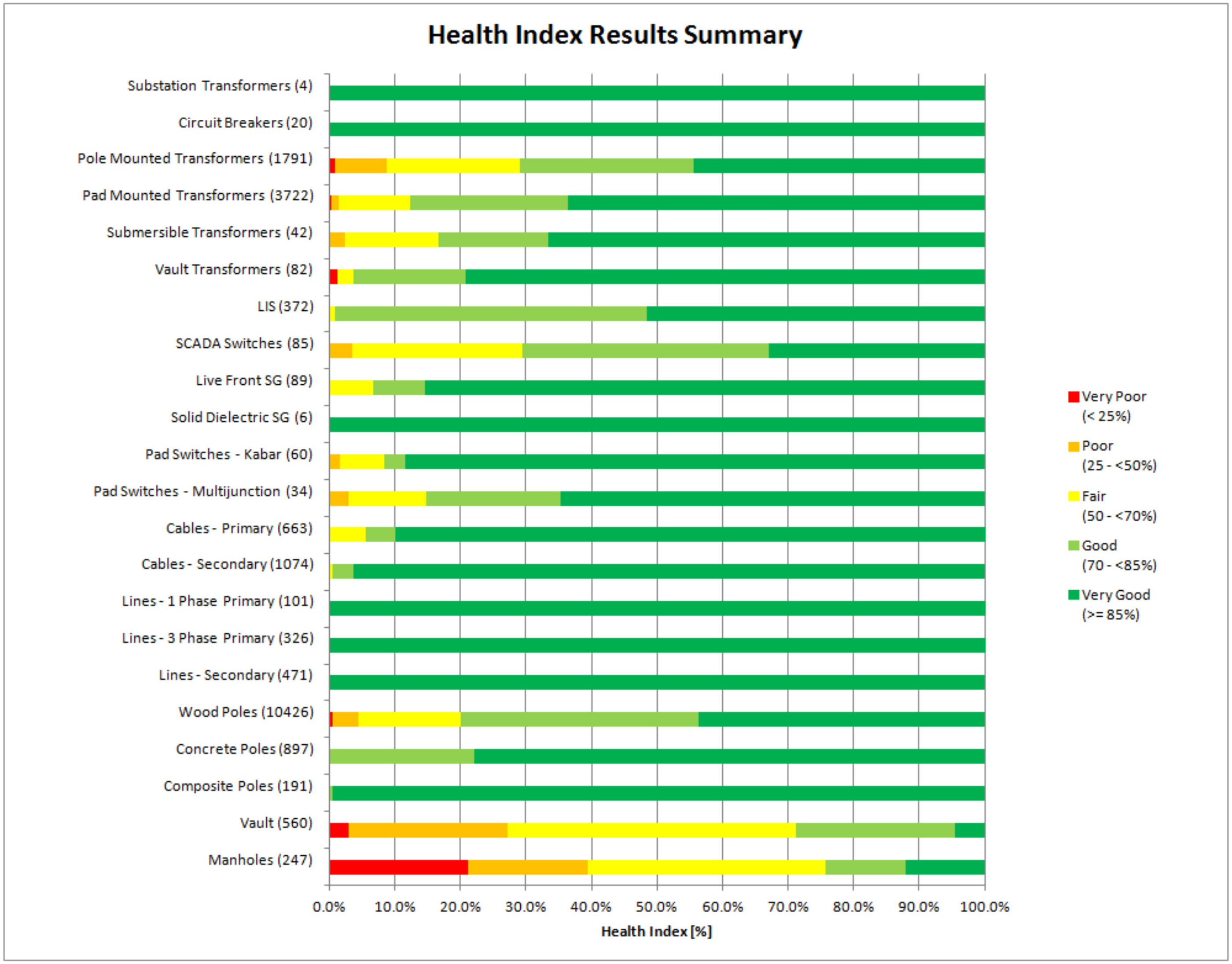


Figure IV-1 Graphical Health Index Results Summary (Population in Parenthesis)

Table IV-2 Year 1 Optimal Condition-Based Flagged for Action Plan and Action Strategy

Asset Category		Condition-Based Replacement Plan for Year 1		Action Strategy
		Number of Units	Percentage of Population	
Substation Transformers		0	0.0%	proactive
Circuit Breakers		0	0.0%	proactive
Pole Mounted Transformers		61	3.4%	reactive
Pad Mounted Transformers		44	1.2%	reactive
Submersible Transformers		1	2.4%	reactive
Vault Transformers		0	0.0%	reactive
Overhead Switches	LIS	0	0.0%	reactive
	SCADA	1	1.2%	reactive
Pad Mounted Switches	Live Front SG	0	0.0%	reactive
	Solid Dielectric SG	0	0.0%	reactive
	Kabar	0	0.0%	reactive
	Multijunction	0	0.0%	reactive
Cables*	Primary	4	0.6%	reactive
	Secondary	4	0.4%	reactive
Lines*	1 Phase Primary	0	0.0%	reactive
	3 Phase Primary	0	0.0%	reactive
	Secondary	1	0.2%	reactive
Poles	Wood Poles	199	1.9%	proactive
	Concrete Poles	0	0.0%	proactive
	Composite Poles	0	0.0%	proactive
Vault		8	1.4%	proactive
Manholes		6	2.4%	proactive

*data in terms of conductor-km

Table IV-3 Twenty-Year Optimal Condition-Based Flagged for Action Plan

Asset Category		Years																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Circuit Breakers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers		61	54	47	43	39	36	37	33	33	31	31	30	31	27	30	35	30	31	35	30
Pad Mounted Transformers		44	39	34	35	35	34	38	37	41	41	44	42	43	43	41	47	47	49	50	52
Submersible Transformers		1	0	0	0	0	0	0	0	0	1	1	1	2	1	0	0	2	1	1	1
Vault Transformers		0	1	0	0	0	0	0	0	0	0	0	1	0	1	2	1	1	2	3	2
Overhead Switches	LIS	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	2	3	4	3	4
	SCADA	1	1	0	1	2	2	1	2	1	1	1	3	2	2	2	2	3	2	2	3
Pad Mounted Switches	Live Front SG	0	0	0	0	0	1	0	0	2	2	0	0	1	0	0	0	1	0	1	1
	Solid Dielectric SG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Kabar	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	2	0	2	1	1
	Multijunction	0	0	0	0	0	0	0	0	1	0	3	0	1	1	1	2	0	2	2	1
Cables*	Primary	4	5	5	6	6	6	7	7	7	8	8	8	8	8	8	8	8	9	9	9
	Secondary	4	5	5	6	6	7	8	9	9	10	11	12	13	14	14	16	17	17	19	19
Lines*	1 Phase Primary	0	0	1	0	0	0	1	0	0	1	0	1	1	0	1	0	1	1	0	1
	3 Phase Primary	0	0	0	1	0	0	0	1	0	0	1	0	1	1	0	1	1	1	1	2
	Secondary	1	1	1	1	1	1	2	2	2	2	3	2	3	2	3	2	3	3	3	4
Poles	Wood Poles	199	170	151	154	157	160	157	144	134	121	106	96	95	94	98	103	114	123	136	150
	Concrete Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Composite Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vault		8	7	6	6	6	4	5	3	4	2	3	2	2	1	1	2	1	0	1	1
Manholes		6	4	3	1	2	0	1	1	1	0	1	1	0	1	0	1	0	1	0	1

*data in terms of conductor-km

Table IV-4 Twenty-Year Levelized Condition-Based Flagged for Action Plan

Asset Category		Years																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Circuit Breakers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole Mounted Transformers		61	54	47	43	39	36	37	31	31	31	32	31	31	32	31	31	32	31	31	31
Pad Mounted Transformers		42	41	42	42	42	41	42	42	42	42	41	42	42	42	42	41	42	42	42	41
Submersible Transformers		0	0	1	0	1	0	1	0	1	0	1	0	1	0	1	1	1	1	1	1
Vault Transformers		1	0	1	0	1	1	0	1	1	1	0	1	1	0	1	1	0	1	1	0
Overhead Switches	LIS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	SCADA	2	1	2	1	2	2	1	2	2	2	1	2	2	1	2	2	1	2	2	1
Pad Mounted Switches	Live Front SG	0	0	1	0	1	0	1	0	1	0	0	1	0	1	0	1	0	1	0	1
	Solid Dielectric SG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Kabar	0	0	1	0	1	0	0	1	0	1	0	0	1	0	1	0	0	1	0	1
	Multijunction	1	0	1	0	1	1	0	1	1	1	0	1	1	0	1	1	0	1	1	0
Cables*	Primary	7	7	7	7	8	7	7	7	7	8	7	7	7	7	8	7	7	7	7	8
	Secondary	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12
Lines*	1 Phase Primary	0	0	1	0	1	0	1	0	1	0	0	1	0	1	0	1	0	1	0	1
	3 Phase Primary	1	0	0	1	0	1	0	1	0	1	1	0	1	0	1	0	1	0	1	1
	Secondary	2	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	2	3
Poles	Wood Poles	199	170	155	156	155	156	157	144	134	112	112	113	112	112	113	112	112	113	112	113
	Concrete Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Composite Poles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vault		8	7	6	6	6	4	5	3	4	2	3	1	2	1	2	2	0	1	1	1
Manholes		6	4	3	0	1	1	0	1	1	0	1	1	1	0	1	1	0	1	1	1

*data in terms of conductor-km

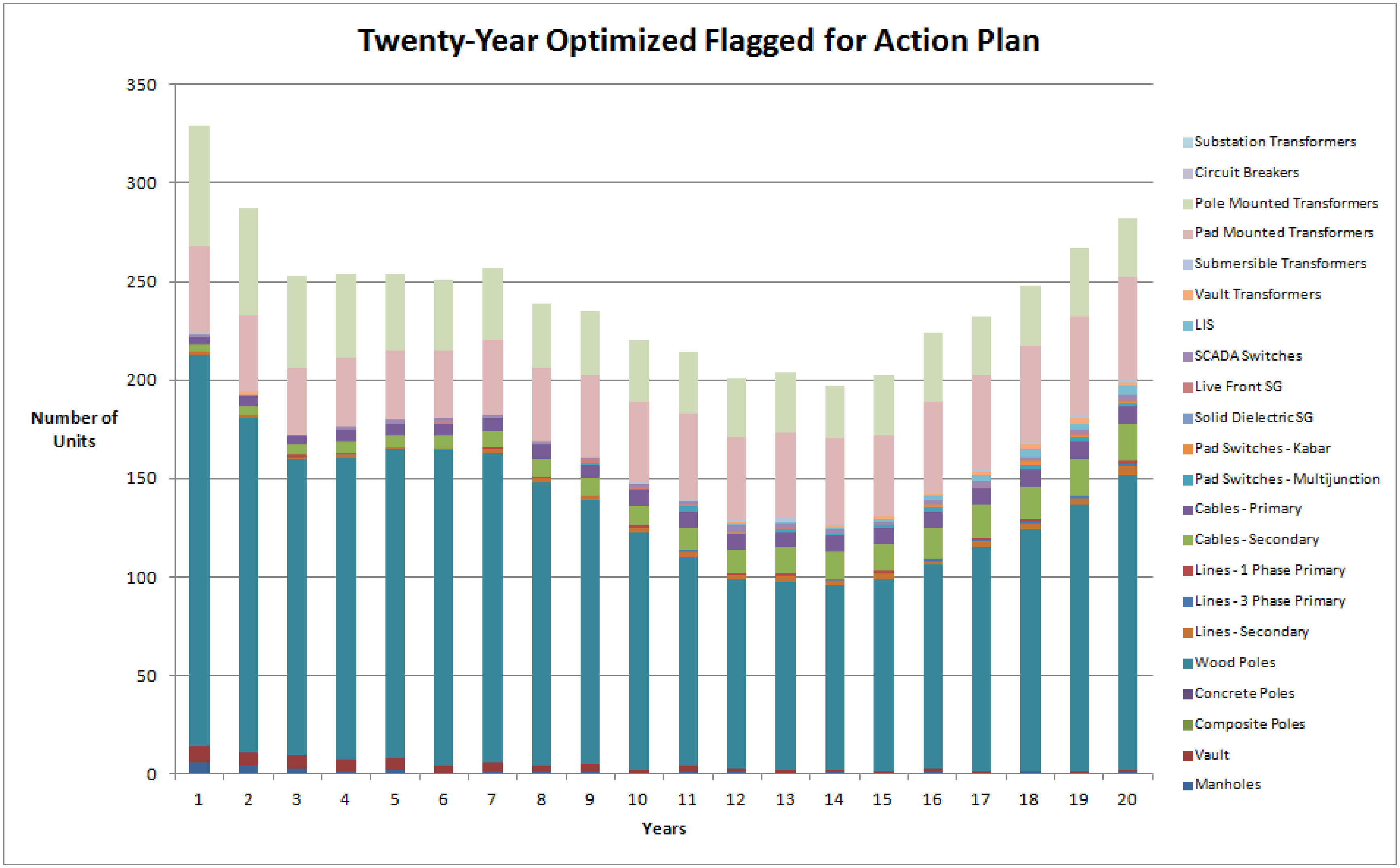


Figure IV-2 Graphical Twenty-Year Optimal Flagged for Action Plan

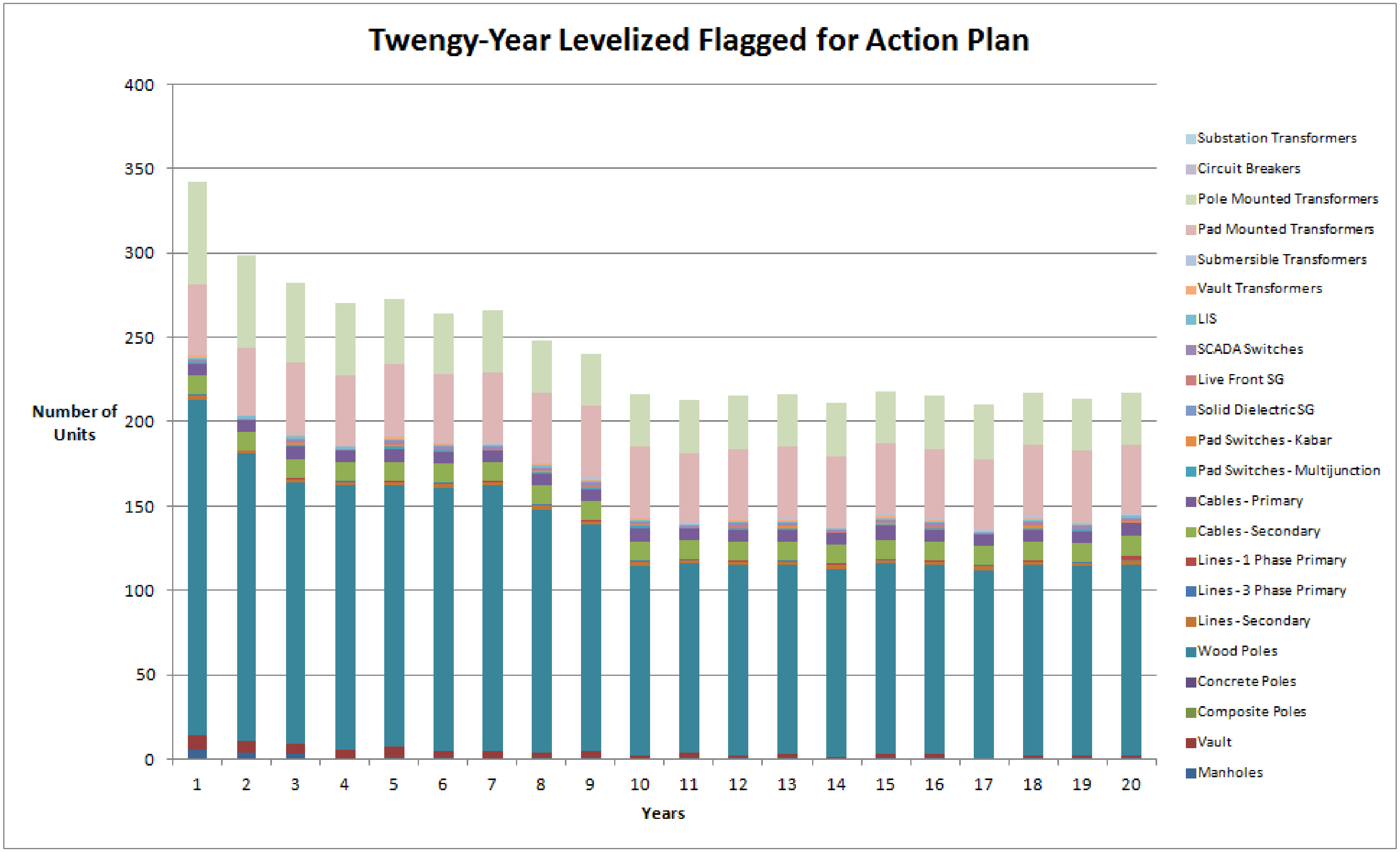


Figure IV-3 Graphical Twenty-Year Levelized Flagged for Action Plan

Data Assessment Results

Data assessment includes determining the data availability indicator (DAI) of each unit, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of condition parameter data currently defined in its Health Index formula. The data gaps for each asset category are shown in Table IV-5. Data gaps are items that are indicators of asset degradation, but are currently not collected or available for any asset in an asset category. The more minimal the data gaps, the higher the quality of available condition data and Health Index formulas.

Table IV-5 Average DAI of All Asset Categories

Asset Category		Average DAI	Sample Size (% of Population)
Substation Transformers		92%	100%
Circuit Breakers		8%	100%
Pole Mounted Transformers		22%	100%
Pad Mounted Transformers		54%	100%
Submersible Transformers		19%	100%
Vault Transformers		95%	100%
Overhead Switches	LIS	28%	100%
	SCADA	29%	100%
Pad Mounted Switches	Live Front SG	79%	100%
	Solid Dielectric SG	20%	100%
	Kabar	17%	100%
	Multijunction	17%	100%
Cables	Primary	21%	100%
	Secondary	21%	100%
Lines	1 Phase Primary	21%	100%
	3 Phase Primary	21%	100%
	Secondary	21%	98%
Poles	Wood Poles	86%	100%
	Concrete Poles	10%	100%
	Composite Poles	3%	99%
Vault		12%	12%
Manholes		13%	13%

The most important data, namely age, inspection records, oil quality and dissolved gas analysis tests, were available for all substation transformers. As such, the average DAI for this asset category is 92%. Winding Doble tests and more specific information related to transformer cooling would improve the HI formula.

Because age was the only data available for breakers, the average DAI is only 8%. The gaps include information on breaker operating mechanism, contacts, interrupter, and insulation.

Age, loading data, and number of customers are available for all distribution transformers. No other data was available for pole mounted and submersible transformers. The average DAI for these asset categories are 31% and 19% respectively. Gaps include inspection data related to exterior tank condition, and transformer connection and insulation. Detailed inspection data was available only for approximately 40% of all pad mounted transformers. The overall DAI for this asset category is 54%. Because detailed inspection data was available for most vault transformers, the average DAI for this category is 95%.

Data for LIS and SCADA switches include age, number of operations, and an indicator of whether a unit has been maintained. Gaps include inspection data related to operating mechanism, interrupter, insulation, and switch condition. Because such data was not available, the average DAIs for LIS and SCADA switches were only 28% and 29% respectively.

Age and inspection records are available for most pad mounted switchgear. The average DAI for this asset category is 79%. Only age was available for solid dielectric padswitches, Kabars, and multijunctions. As such, the average DAIs for these categories are only 20%, 17%, and 17% respectively. Data gaps for these categories include inspection records related to physical condition (corrosion, access, base), and terminations and connections condition.

Age was the only data available for primary and secondary cables. Data related to splices and terminations, maintenance records, fault history, and loading were not available. As such, the DAIs for primary and secondary cables are only 21% and 21% respectively.

Overhead lines (single phase, three phase, and secondary) had only age data available. The DAIs for all three asset categories is 21%. Data gaps include information on repairs and splices and corrective maintenance records.

Age, pole strength, and detailed inspection records are available for wood poles. There are no data gaps and the average DAI is 81%. While age is available for most concrete poles, only 10% of poles have inspection data. As such, the average DAI is 10% only. Similarly, only 5% of composite poles have inspection records. The average DAI of composite poles is therefore only 3%.

Inspection data related to wall, floor, and ceiling conditions was collected for vaults and manholes. However, only 12% of vaults and 13% of manholes were inspected. As such, the average DAIs were only 12% and 13% respectively.

In summary, the following asset categories had fairly high data availability indicators: substation transformers, vault transformers, live front pad mounted switchgear, and wood poles. Good condition data was available was available for most of the units in these asset categories. Circuit breakers, Kabars and multijunction, lines and cables had only age available. Further, although pad mounted transformers, concrete and composite poles are being inspected, inspection records were only partially available for these asset categories

This page is intentionally left blank.

V CONCLUSIONS AND RECOMMENDATIONS

This page is intentionally left blank.

V Conclusions and Recommendations

1. An Asset Condition Assessment was conducted for GHESI's key distribution assets, namely substation transformers, circuit breakers, distribution transformers (pole mounted, pad mounted, submersible, vault), overhead switches (LIS, SCADA), pad mounted switches (live front, solid dielectric, Kabar, multijunction), cables (primary, secondary), lines (1 phase primary, 3 phase primary, secondary), poles (wood, concrete, composite), vaults, and manholes.

2. Underground civil structures were found to be, on average, in the worst condition. The average Health Index for manholes and vaults are 51% and 58% respectively. Approximately 39% of manholes and 27% of vaults are in poor or very poor condition.

   It should be noted that because the samples used in the assessment were suspect units or in suspect locations, the samples may not be representative of the vault and manhole populations. It is likely that the remainders of the vault and manhole population are, on average, in better condition than the sampled units.

   The sample sizes for vaults and manholes are only 12% and 13% respectively. It is recommended that inspections be conducted for more representative samples of the vault and manhole populations. A more random and representative sample pool will allow the Health Index results to be extrapolated over the populations.

3. Other asset categories worth noting are pole mounted transformers, wood poles, and SCADA switches. Approximately 9% of pole mounted transformers, 4% of wood poles, and 4% of SCADA switches are in poor or very poor condition.

4. Wood poles was identified as having the biggest quantity of units flagged for action in the first year. Nearly 200 poles (1.9% of the population) require action in the first year.

5. Sixty-one (61) pole mounted transformers (3.4% of the population) and 44 pad mounted transformers (1.2% of the population) are flagged for action in the first year.

6. Eight (8) vaults (1.4% of the population) and 6 manholes (2.4% of the population) need to be addressed.

7. 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 GHESI's asset management process.

8. Substation transformers, vault transformers, live front pad mounted switchgear, and wood poles had good condition data available for most units. As such, these asset categories had fairly high data availability indicators.

9. Circuit breakers, Kabars and multijunction, lines and cables had only age data available.

10. Good condition data is being collected for pad mounted transformers. Such inspection data was, however, only available for 40% of the population. Similarly, only 10% of concrete poles and 5% of composite poles have inspection data. Effort should be made to collect inspection records for the rest of these populations.

11. The data gaps for all asset categories, if applicable, were identified. It is recommended that efforts be made to close the data gaps in a prioritized manner.

VI APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

This page is intentionally left blank.

1 Substation Transformers

1.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Substation Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Substation Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Insulation	11	Oil Quality	3	
		Oil DGA	6	
Cooling	1	Fan	1	
Sealing & Connection	2	Oil Conservator	1	
		Physical Check	1	
		Oil Leak	1	
Service Record	6	Loading	5	
		Age	3	

1.1.2 Condition Parameter Criteria

Oil Quality

Table 1-2 Substation Transformers Oil Quality Test Criteria

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

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

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

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

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

Oil DGA

Table 1-3 Substation Transformers Oil DGA Criteria

CPF	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

*NOTE: 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:

2.5 MVA to Under 10 MVA

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=70	<=100	<=200	<=400	<=1000	>1000	4
CH4(Methane)	<=70	<=120	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=75	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	5
CO	<=750	<=1000	<=1300	<=1500	<=1700	>2000	4*
CO2	<=7500	<=8500	<=9000	<=12000	<=15000	>15000	4*
CO2/CO	3 - <10	<12	<15 Or <3	<18	<20	>20	4*
*If CO ≥ 500 ppm and CO2 ≥ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4) If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)							

10 MVA and Higher

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=40	<=100	<=300	<=500	<=1000	>1000	4
CH4(Methane)	<=80	<=150	<=200	<=500	<=700	>700	3
C2H6(Ethane)	<=70	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=500	<=600	<=1000	<=1500	>1500	4*
CO2	<=3000	<=4500	<=5700	<=7500	<=10000	>12000	4*
CO2/CO	3 - <8	< 10	<13 Or <3	<14	<15	>15	4*
*If CO ≥ 500 ppm and CO2 ≥ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4) If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)							

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

Winding Doble Test

Table 1-4 Substation Transformers Winding Doble Test Criteria

CPF	Description
4	%PF < 0.5%
3	0.5% < %PF < 0.7%
2	0.7% < %PF < 1%
1	1.0% < %PF < 2.0%
0	%PF > 2.0%

Age

Assume that the failure rate for 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 55 years the probability of failures (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

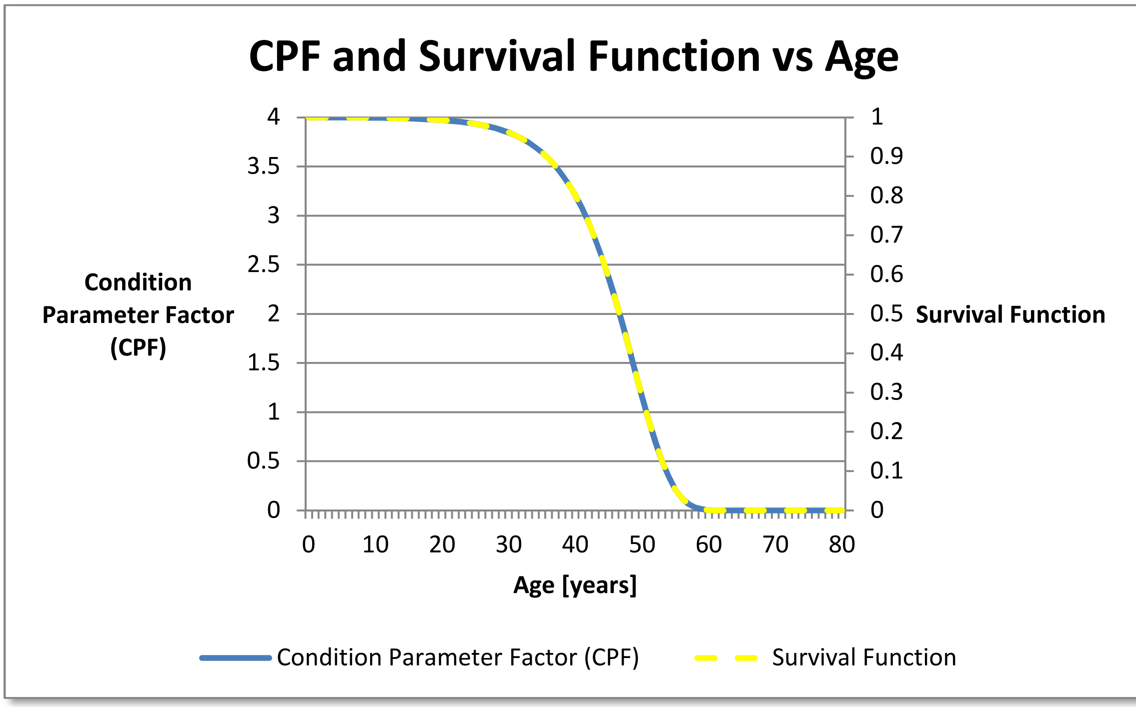


Figure 1-1 Substation Transformers Age Condition Criteria

<u>Loading History</u>

Table 1-5 Substation Transformers Loading History

Data: S1, S2, S3, …, SN recorded data
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 Sub-Factor 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 Sub-Factor Score should be multiplied by 0.6 to show the effect of overheating.

1.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 6 years.

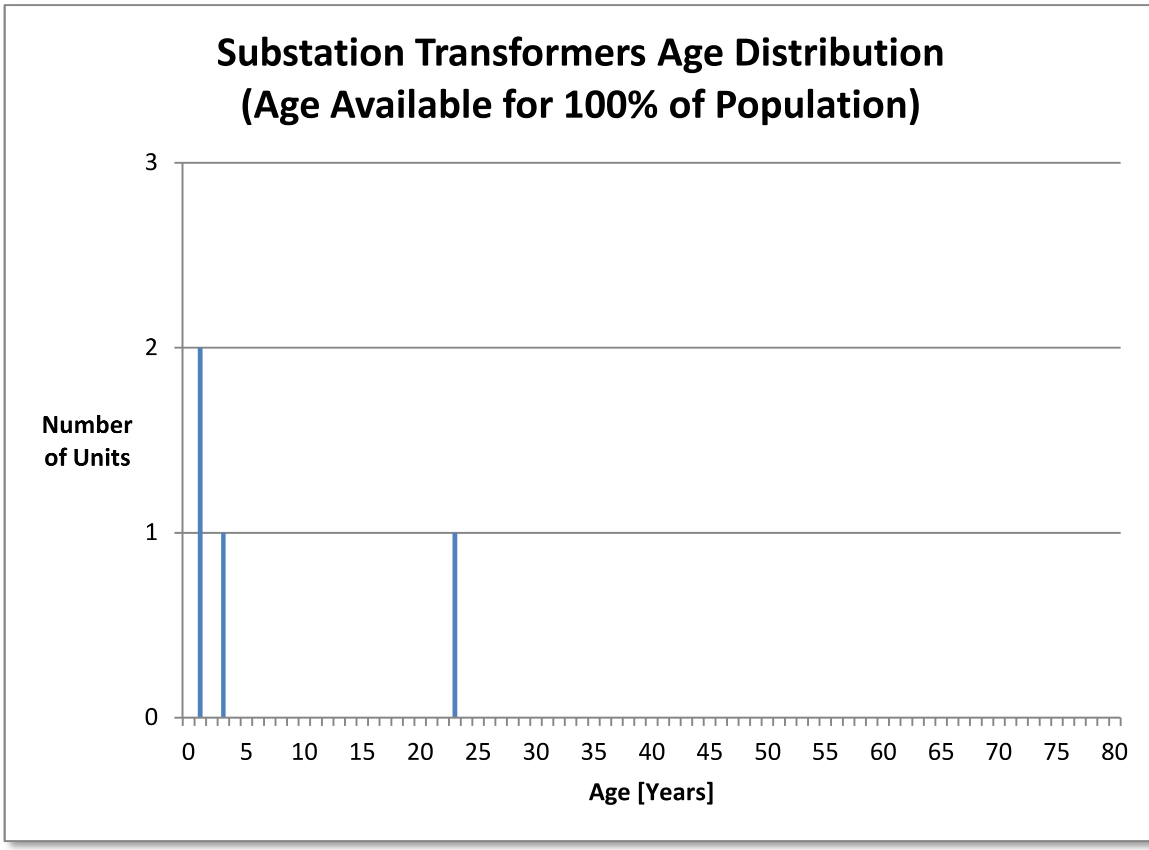


Figure 1-2 Substation Transformers Age Distribution

1.3 Health Index Results

There are 4 in-service Substation Transformers at GHESI. Of these, 4 units had sufficient data for assessment.

The average Health Index for this asset group is 94%. None were in poor or very poor condition.

The Health Index Distribution is shown in Figure 1-3 through Figure 1-5.

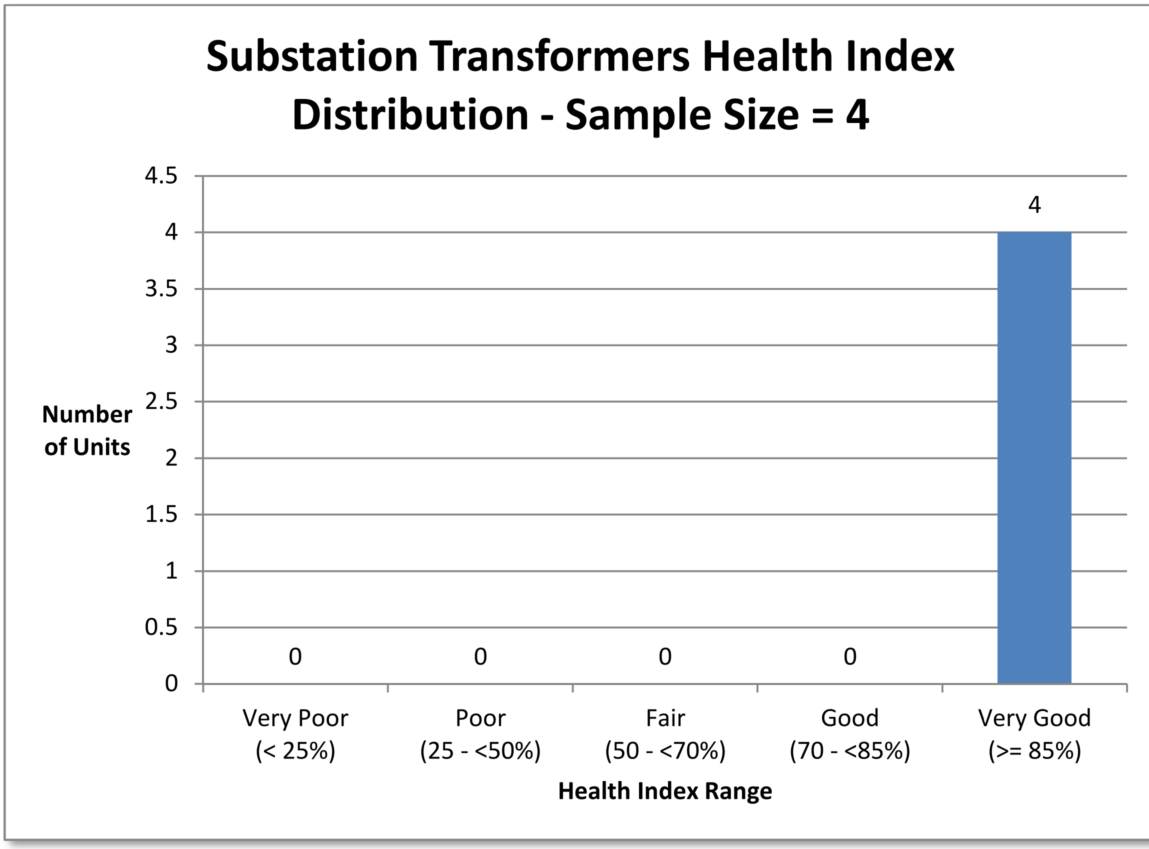


Figure 1-3 Substation Transformers Health Index Distribution (Number of Units)

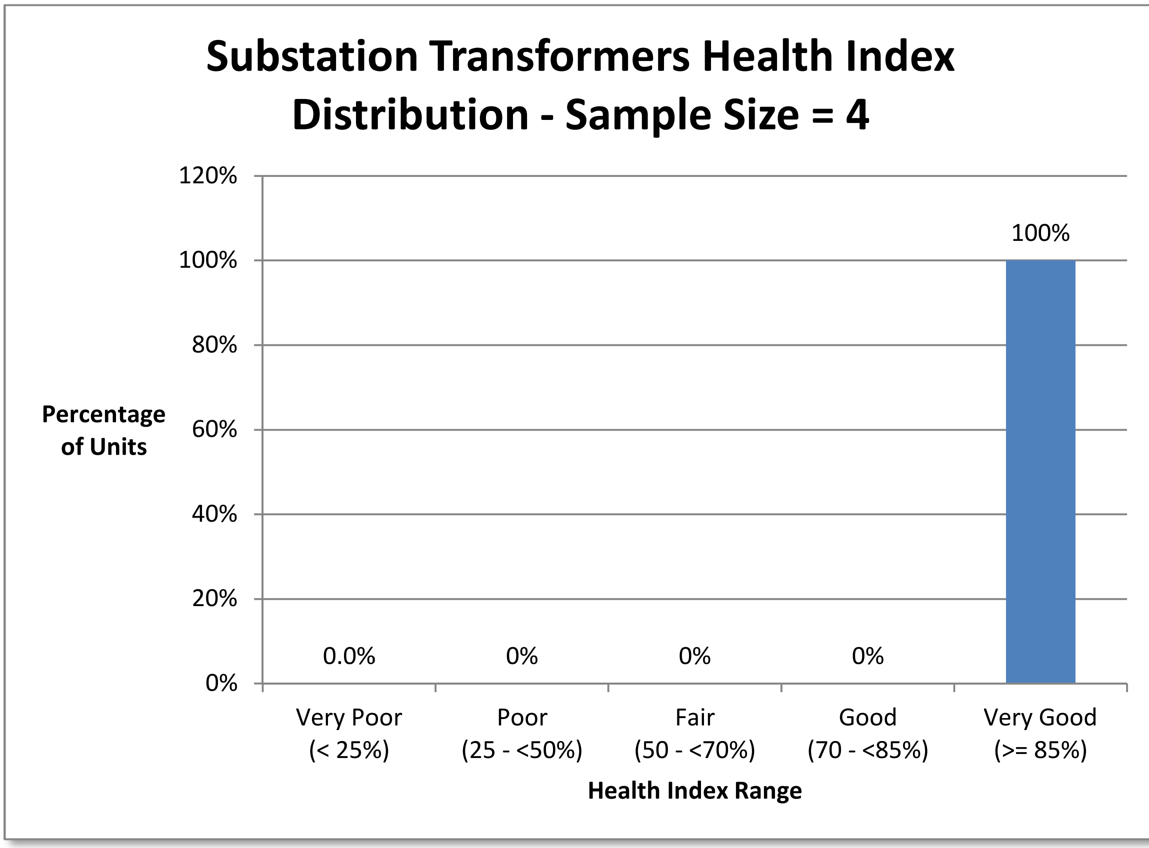


Figure 1-4 Substation Transformers Health Index Distribution (Percentage of Units)

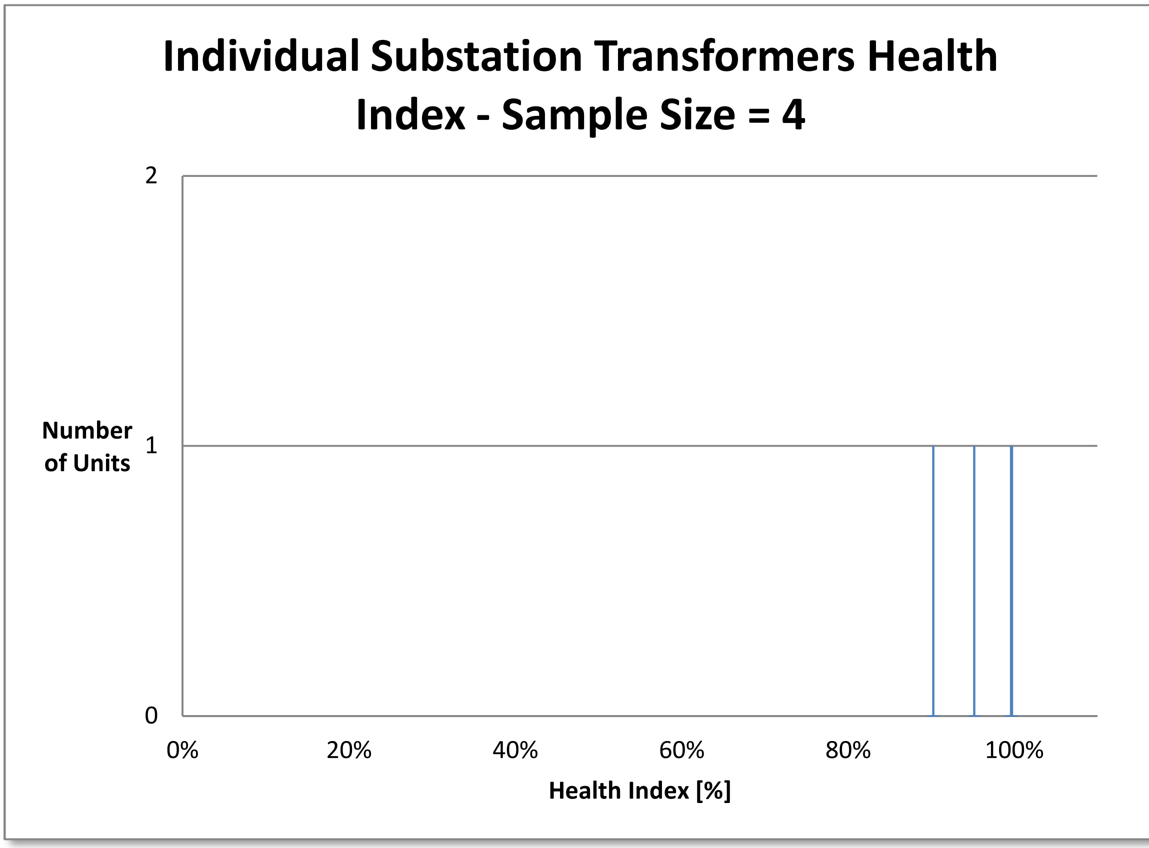


Figure 1-5 Substation Transformers Health Index Distribution by Value (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 1-6 Health Index Results for Each Substation Transformers Unit

Transformer	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category
Rockwood MS-2	3	94%	**90.3%**	Very Good
Rockwood MS-1	23	90%	**95.0%**	Very Good
Arlen T2	1	91%	**95.2%**	Very Good
Arlen T1	1	91%	**95.3%**	Very Good

1.4 Condition-Based Flagged for Action Plan

Based on transformer condition, no units are flagged for action in the next 20 years.

1.5 Data Analysis

1.5.1 Data Gap

The data available for Substation Transformers includes age, inspection results, oil quality, dissolved gas analysis. Although much of the critical data, namely oil quality and DGA, are available and included in the Health Index formula, additional data may be collected and used to improve the Health Index formulation. These are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Winding Doble Test	Insulation	☆ ☆ ☆	Transformer windings	Power/dissipation factor indicating insulation deterioration	On-site measurement test
Cooling	Cooling	☆ ☆ ☆	Cooling oil	Abnormal oil flow	Visual Inspection / On-site Reading / IR Scans
				Abnormal oil pump motor	
			Radiator	Plugged radiator	
			Valves	Broken valves	
			Transformer tank	High top oil temperature	
			Winding	High winding temperature	
Primary and Secondary Connector	Sealing & Connection	☆	Cable connection	Defects due to installation	Visual inspection
			Pothead		
Main Tank Desiccant		☆	Transformer tank breather	Desiccant seal failure	Visual inspection

1.5.2 *Data Availability Distribution*

The average DAI for Substation Transformers is 92%. All units had age, oil and DGA tests, as well as inspection results.

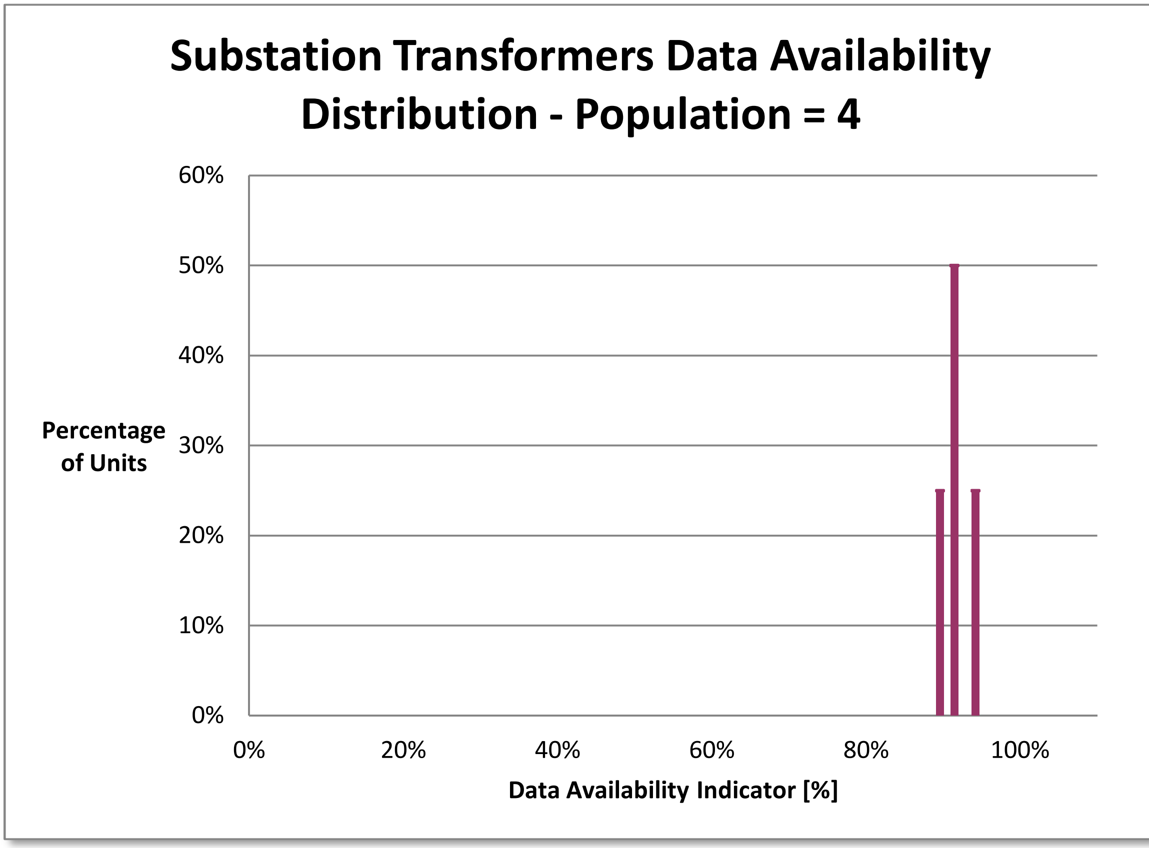


Figure 1-6 Substation Transformers Data Availability Distribution

2 Breakers

2.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Breakers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Breakers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Operating Mechanism	14	Lubrication	1	
		Linkage	1	
		cabinet	1	
Contact Performance	7	Trip Time	1	
		Closing Time	1	
		Contact Wear	1	
Arc Extinction	5	Arc Extinction Mechanism	1	
Insulation	2	Insulation	1	
Service Record	5	Overall Condition	1	
		Age	1	Figure 2-1

2.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for 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 60 years the probability of failures (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

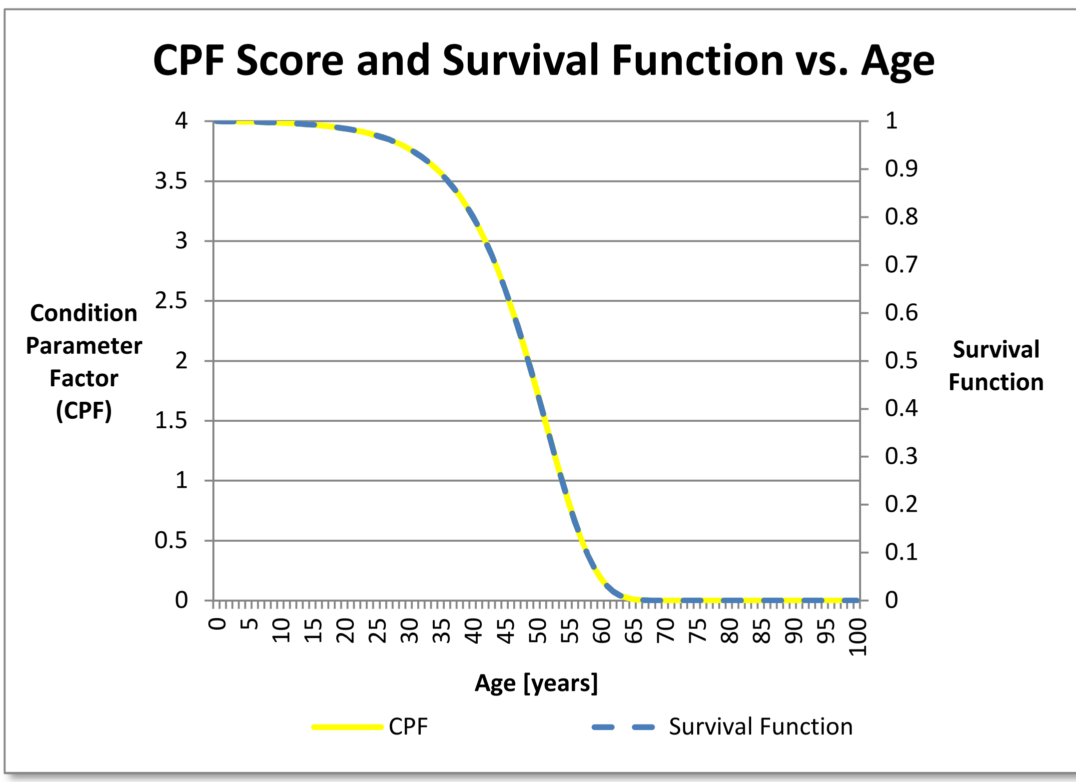


Figure 2-1 Breakers Age Condition Criteria

2.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 14 years.

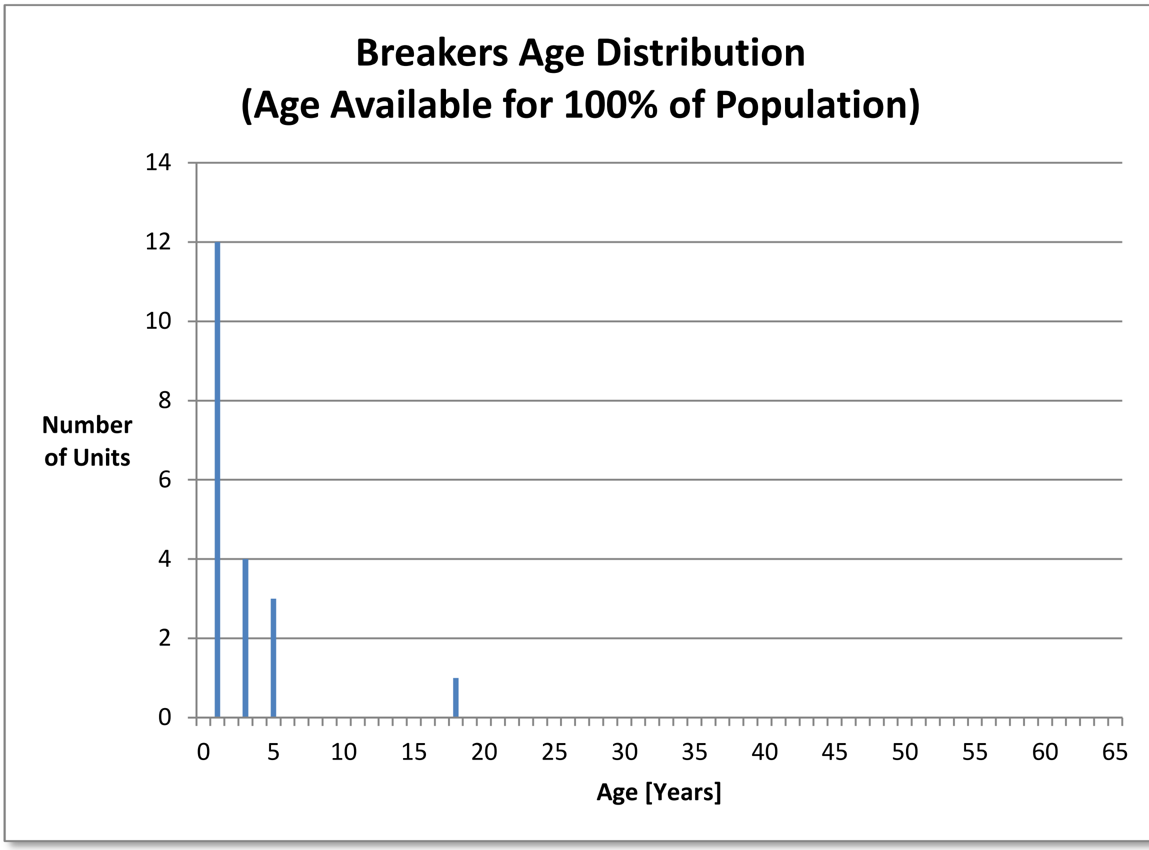


Figure 2-2 Breakers Age Distribution

2.3 Health Index Results

There are 20 in-service Breakers at GHESI. Of these, 20 units had sufficient data for assessment.

The average Health Index for this asset group is 100%. None were found to be in poor or very poor condition.

The Health Index Distribution is shown in Figure 2-3 through Figure 2-5.

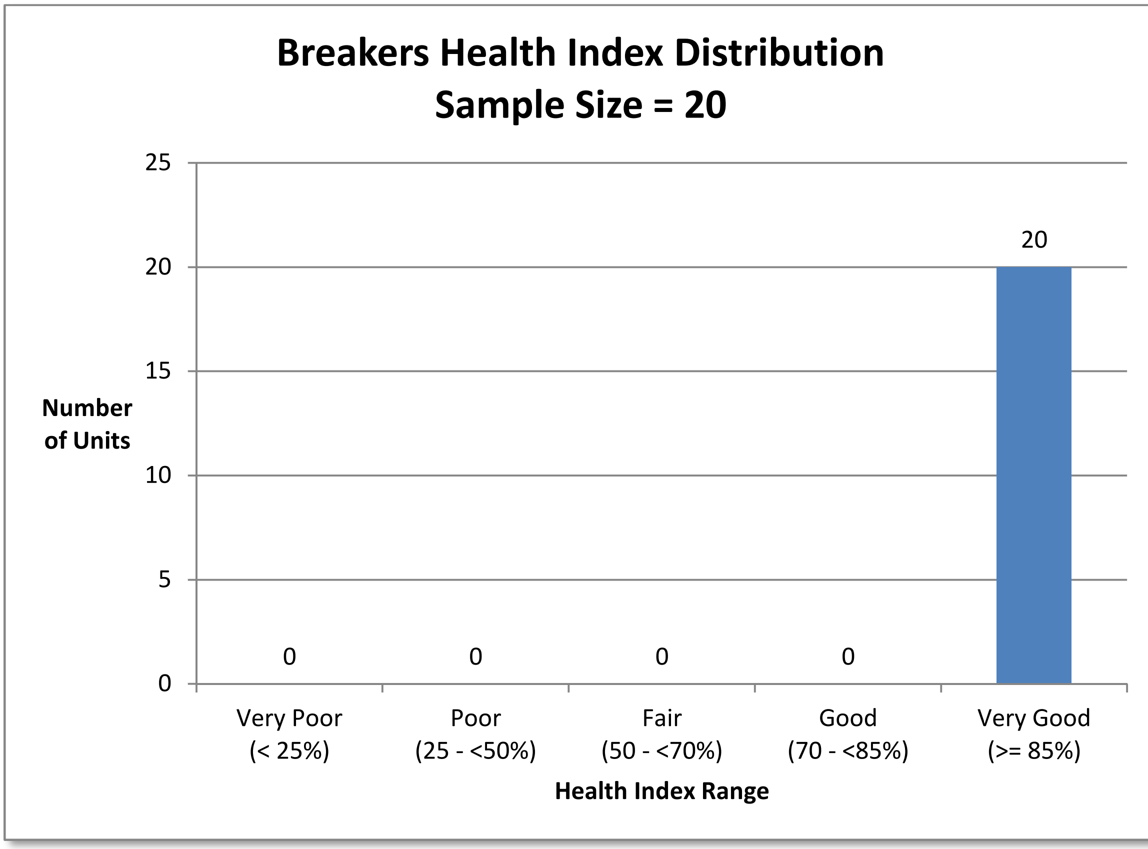


Figure 2-3 Breakers Health Index Distribution (Number of Units)

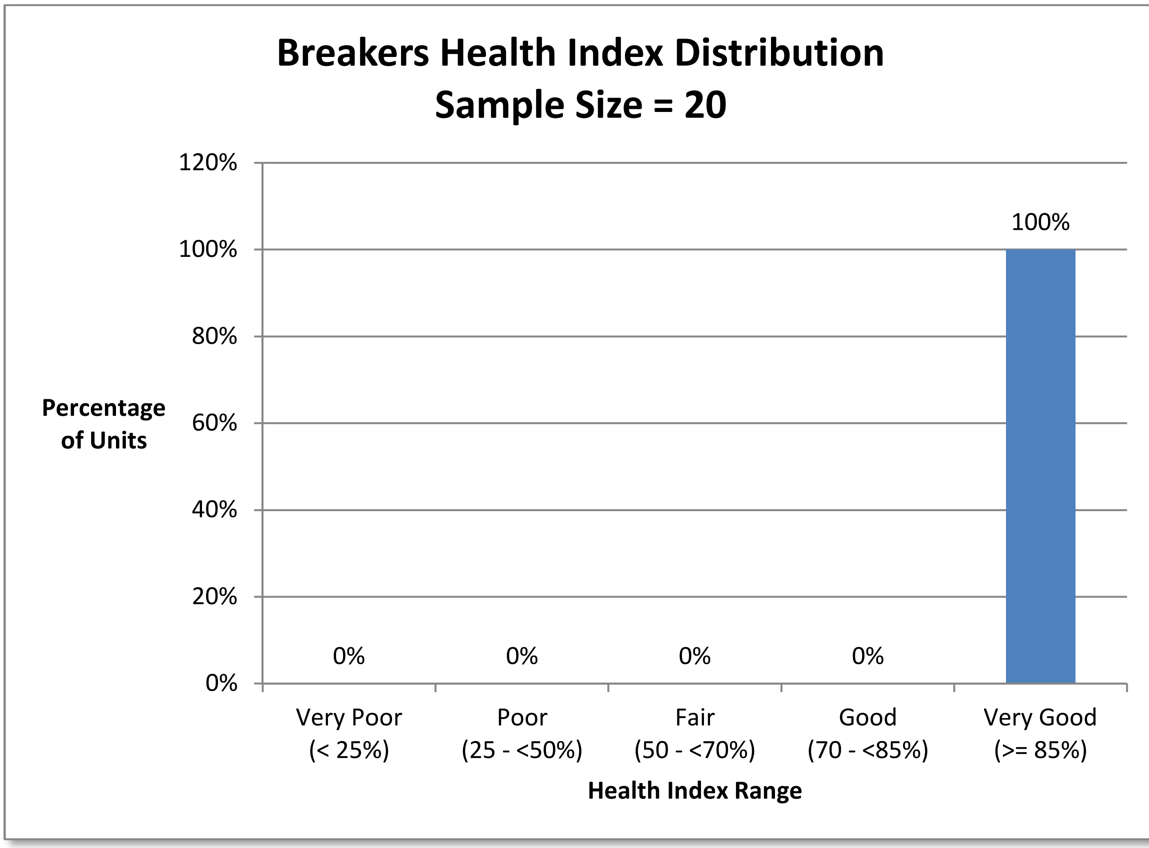


Figure 2-4 Breakers Health Index Distribution (Percentage of Units)

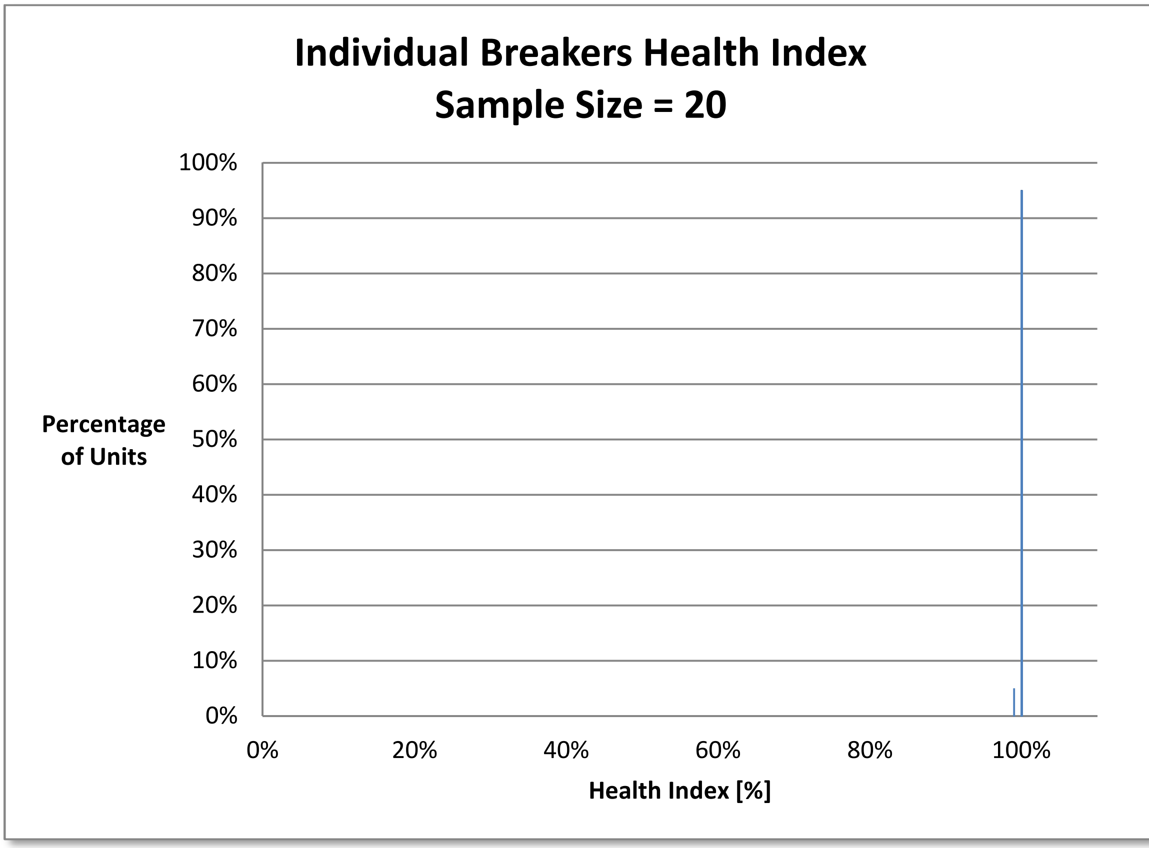


Figure 2-5 Breakers Health Index Distribution by Value (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 2-2 Health Index Results for Each Breakers Unit

Transformer	Station Number	Age	Data Availability	Health Index	Health Index Category
86	MS1-F1	18	100%	**98.9%**	Very Good
84	MS1-T1B	5	100%	**99.9%**	Very Good
85	MS1-F2	5	100%	**99.9%**	Very Good
102	MS1-F3	5	100%	**99.9%**	Very Good
78	MS2-F3	3	100%	**99.9%**	Very Good
81	MS2-T1B	3	100%	**99.9%**	Very Good
82	MS2-F2	3	100%	**99.9%**	Very Good
83	MS2-F1	3	100%	**99.9%**	Very Good
92	T1B	1	100%	**100.0%**	Very Good
93	T2Y	1	100%	**100.0%**	Very Good
94	7356F22	1	100%	**100.0%**	Very Good
95	7356F23	1	100%	**100.0%**	Very Good
96	7356F12	1	100%	**100.0%**	Very Good
97	7356F13	1	100%	**100.0%**	Very Good
98	YB	1	100%	**100.0%**	Very Good
99	BY	1	100%	**100.0%**	Very Good
100	7356F11	1	100%	**100.0%**	Very Good
103	7356F24	1	100%	**100.0%**	Very Good
104	7356F14	1	100%	**100.0%**	Very Good
105	7356F21	1	100%	**100.0%**	Very Good

2.4 Condition-Based Replacement Plan

Based on breaker condition, no units are flagged for action in the next 20 years.

2.5 Data Analysis

2.5.1 Data Gaps

The data available for Breakers was age only. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Linkage	Operating Mechanism	☆☆☆	Operating system	Mechanical part and linkage issue	Visual inspection
Lubrication		☆☆☆	Lubricants	Lubricant ageing	Visual inspection
Cabinet		☆	Control cabinet	Cable termination issue Door sealing gasket issue Space heater issue Metallic surface corrosion	Visual inspection
Closing Time	Contact Performance	☆	Breaker performance	Time from energizing the opening circuit to fully closed	Measurement / Testing
Trip Time		☆	Breaker performance	Duration of current interruption	Measurement / Testing
Arcing Contact		☆☆	Arcing contact	Arcing contact wear	Measurement / Testing
SF6 Leak	Arc Extinction	☆☆	SF6 Breaker Poles	Gas density drop	On-site reading (Using SF6 gas density monitor)
Vacuum Bottle		☆☆	Vacuum CB	Vacuum status check	On-site test (Through hi-pot test)
Dielectric Test	Insulation	☆☆	Insulation	Insulation issue	Measurement / Testing

2.5.2 Data Availability Distribution

The average DAI for Breakers is 8% because all breakers were had age.

The data availability distribution for the population is shown in Figure 2-6.

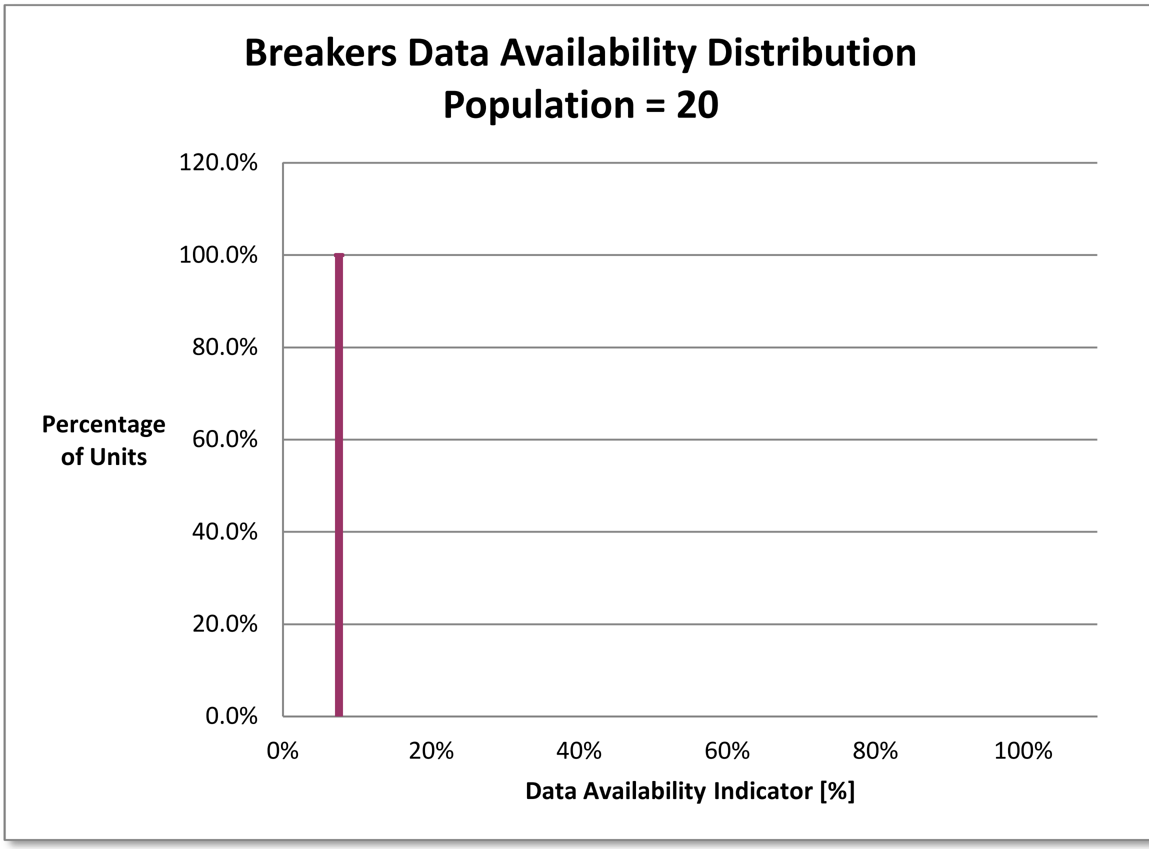


Figure 2-6 Breakers Data Availability Distribution

3 Pole Mounted Transformers

3.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Pole Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Pole Mounted Transformers Condition Weights and Maximum CPS

<table>
<tr><th>Condition Parameter</th><th>Condition Parameter Weight</th><th>Sub-Condition Parameter</th><th>Sub-Condition Parameter Weight</th><th>Criteria Lookup Table</th></tr>
<tr><td>Physical Condition</td><td>1</td><td>Corrosion</td><td>1</td><td></td></tr>
<tr><td rowspan="4">Connection and Insulation</td><td rowspan="4">4</td><td>Oil Leak</td><td>5</td><td></td></tr>
<tr><td>Connection</td><td>2</td><td></td></tr>
<tr><td>Grounding</td><td>1</td><td></td></tr>
<tr><td>Bushing</td><td>2</td><td></td></tr>
<tr><td rowspan="4">Service Record</td><td rowspan="4">3</td><td>Number of Customers</td><td>1</td><td>Table 3-2</td></tr>
<tr><td>Age</td><td>2</td><td>Figure 3-1</td></tr>
<tr><td>Loading</td><td>2</td><td>Table 3-3</td></tr>
<tr><td>Overall Condition</td><td>2</td><td></td></tr>
</table>

3.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Pole Mounted 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 failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

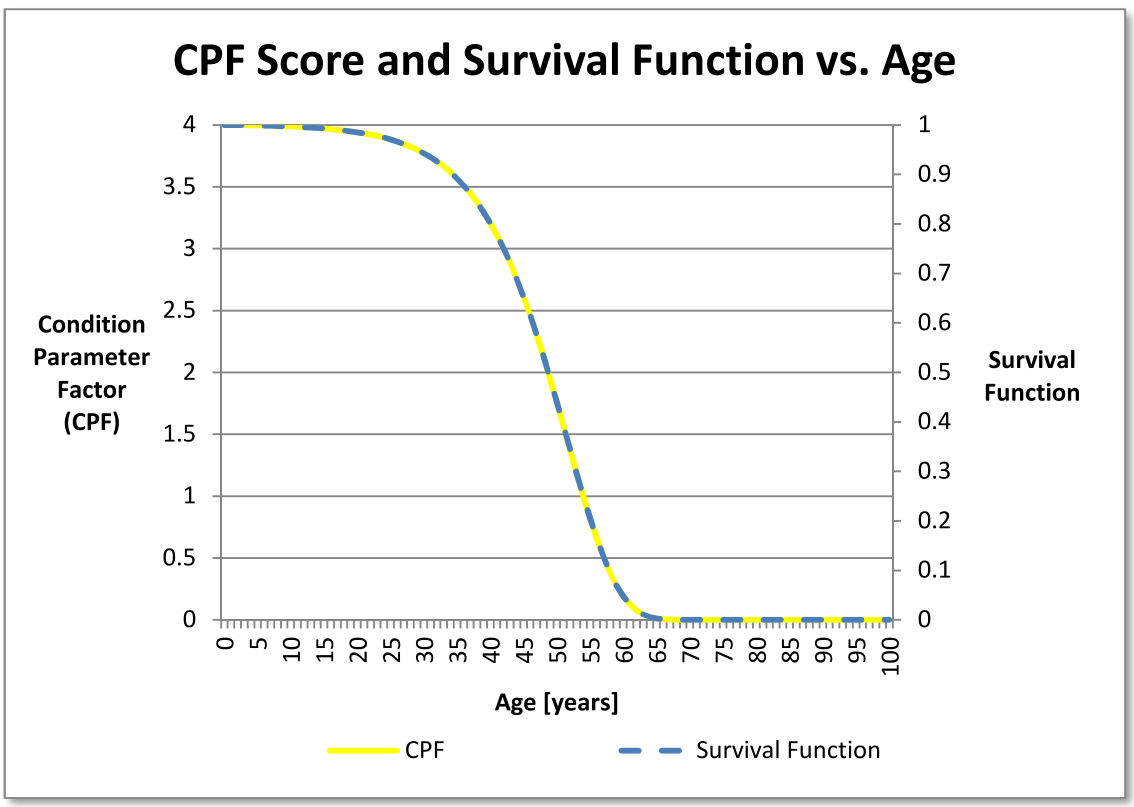


Figure 3-1 Pole Mounted Transformers Age Condition Criteria

Number of Customers

Table 3-2 Pole Mounted Transformers Number of Customers Description and Score

Number of Customers		Score
Transformer Size > 100 kVA	**Transformer Size <= 100 kVA**	
0-9	0-9	4
10-19	10-14	3
20-39	15-19	2
40+	20+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating}$$

Table 3-3 Pole Mounted Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

3.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 64% of the population. The average age was found to be 20 years.

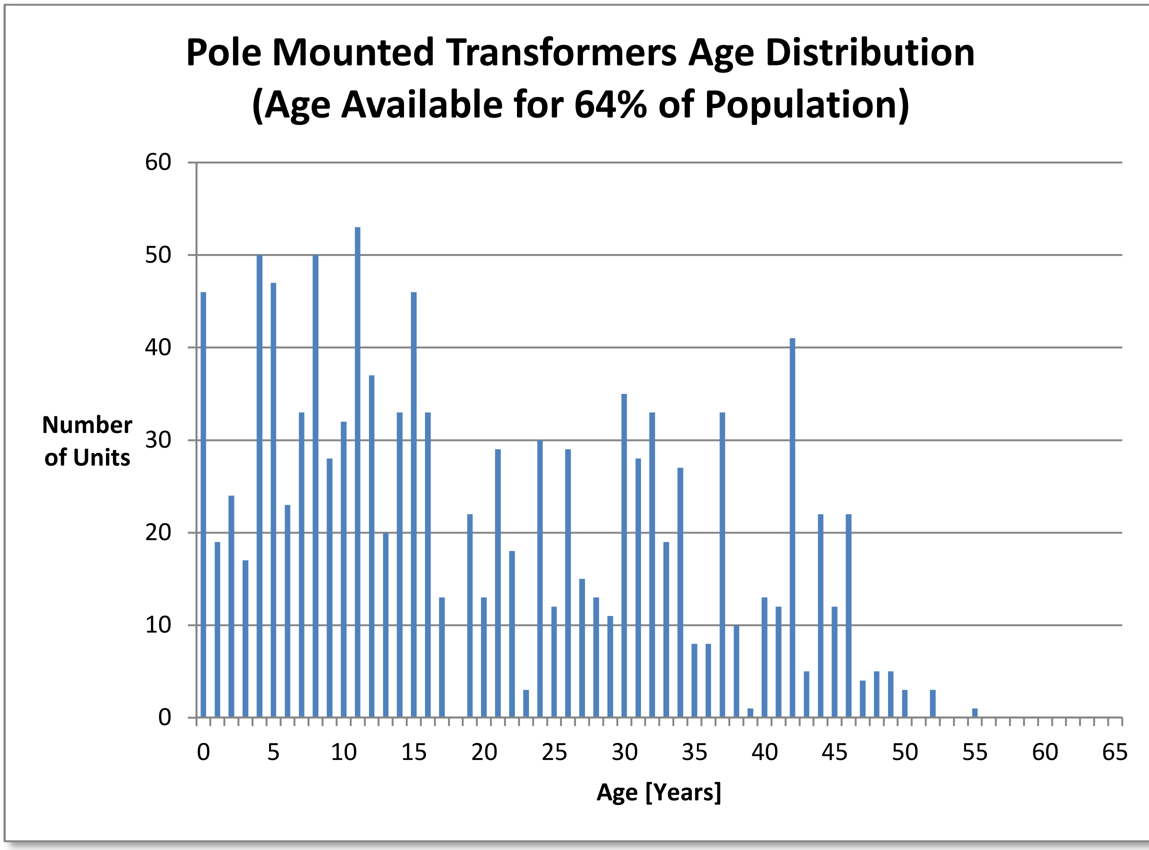


Figure 3-2 Pole Mounted Transformers Age Distribution

3.3 Health Index Results

There are 1791 in-service Pole Mounted Transformers at GHESI. There were 1789 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 81%. Approximately 9% of the units were found to be in poor condition.

The Health Index Results are as follows:

Figure 3-3 Pole Mounted Transformers Health Index Distribution (Number of Units)

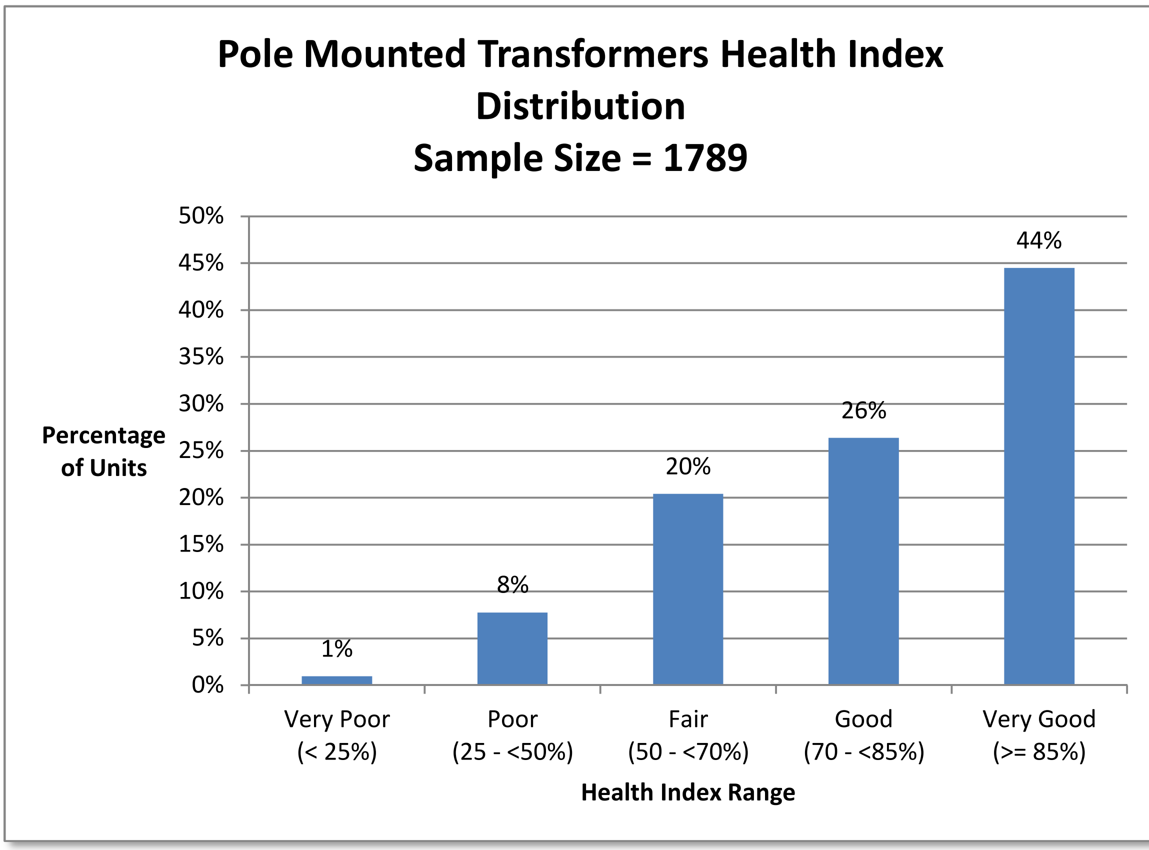


Figure 3-4 Pole Mounted Transformers Health Index Distribution (Percentage of Units)

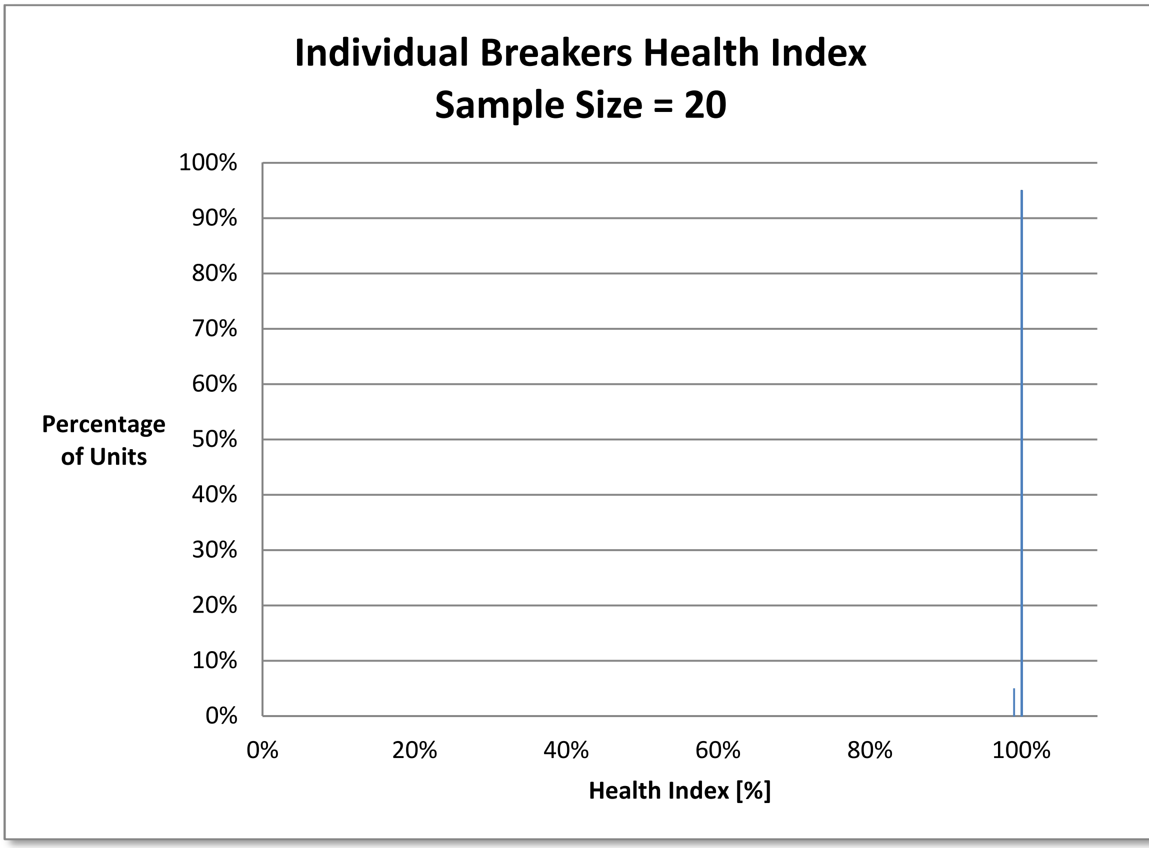


Figure 3-5 Pole Mounted Transformers Health Index Distribution by Value (Percentage of Units)

3.4 Condition-Based Flagged for Action Plan

As it is assumed that Pole Mounted Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a “levelized” plan, based on accelerating or replacing prior to expected time of action, is also given.

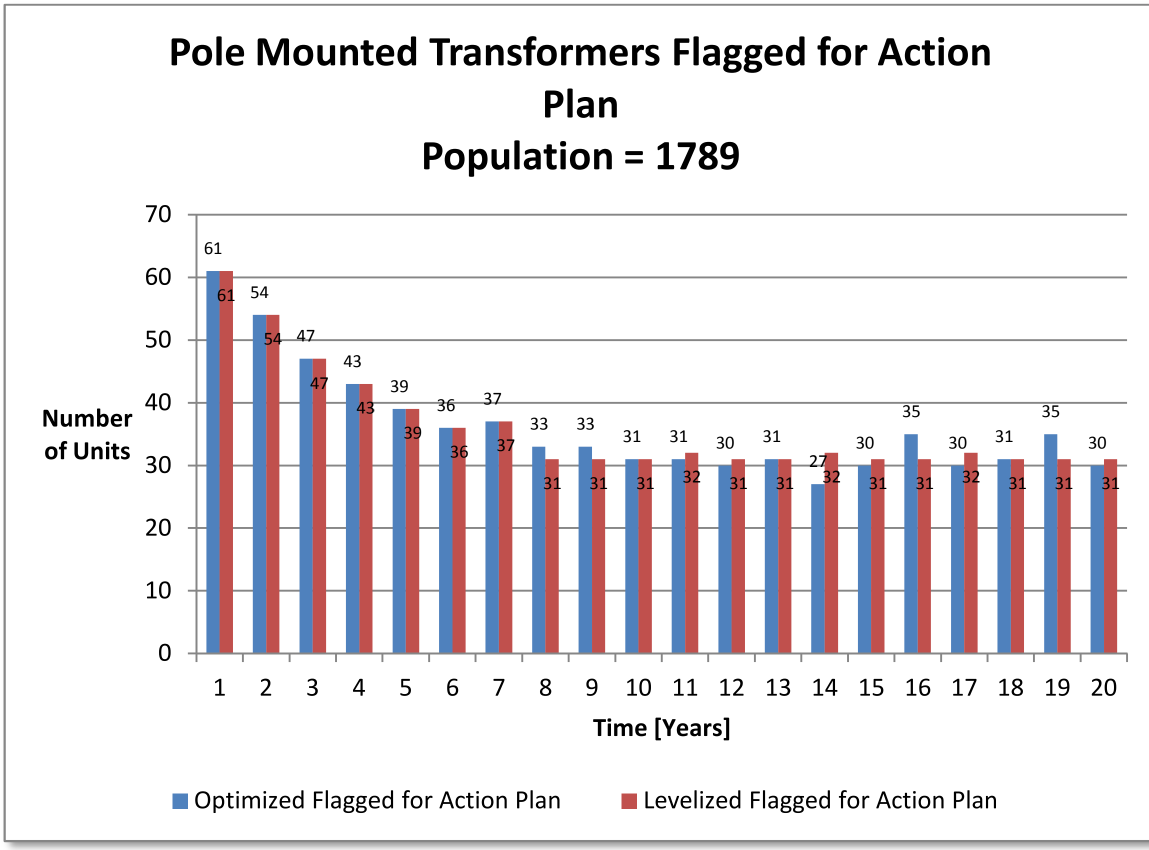


Figure 3-6 Pole Mounted Transformers Condition-Based Flagged for Action Plan

3.5 Data Analysis

3.5.1 Data Gap

The data available for Pole Mounted Transformers is age, loading, and number of customers. The data gaps, which are primarily from inspections, are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection
Connection		☆☆	Transformer connection	Poor connection	Visual inspection
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Bushing		☆☆	Porcelain	Crack / Dirt	Visual inspection
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Operation record

3.5.2 Data Availability Distribution

Because inspection data was not available for this asset category, the average DAI for Pole Mounted Transformers is 22%.

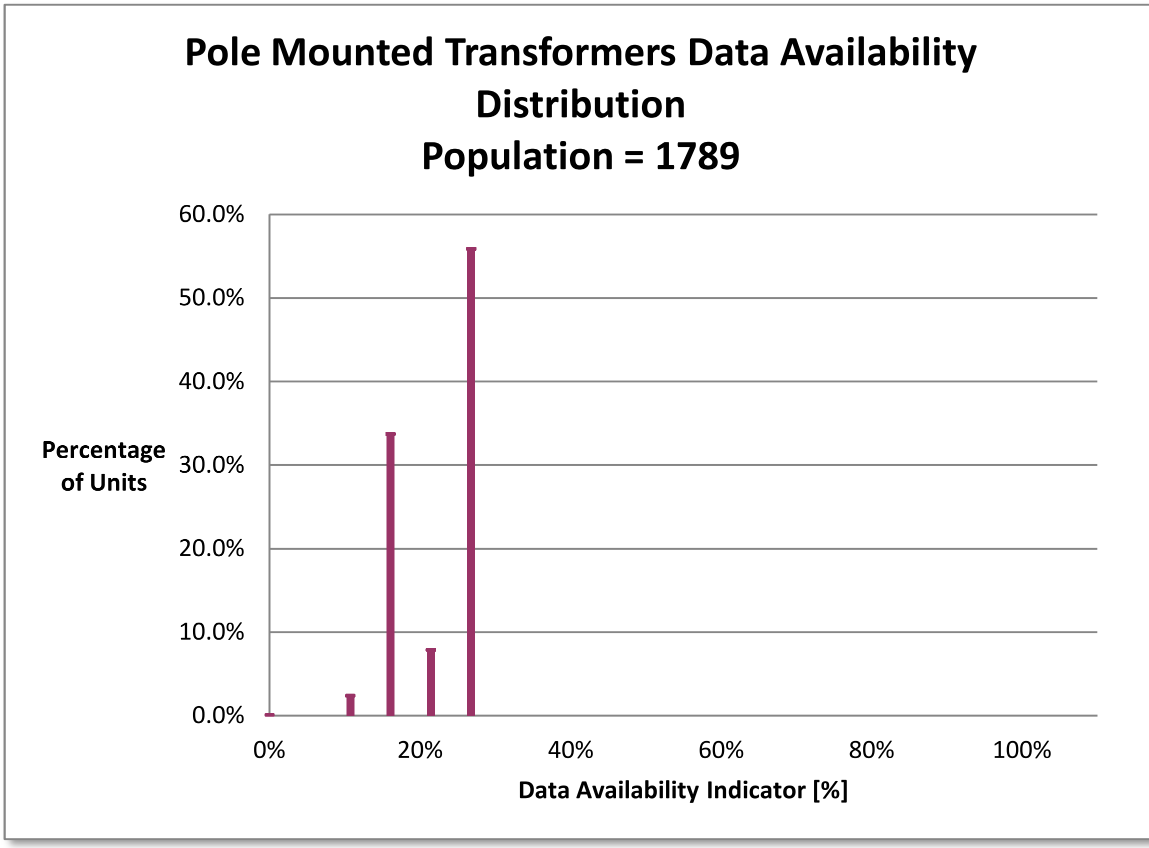


Figure 3-7 Pole Mounted Transformers Data Availability Distribution

4 Pad Mounted Transformers

4.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Pad Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Pad Mounted Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	3	Corrosion	2	Table 4-4
		Access	1	Table 4-4
		Base	1	Table 4-4
Connection and Insulation	5	Oil Leak	1	Table 4-4
		Connection	2	Table 4-4
		Barrier	2	Table 4-4
		Elbow	2	Table 4-4
		Stress Cone	2	Table 4-4
		Bushing	2	Table 4-4
Service Record	5	Overall Condition	2	Table 4-4
		Number of Customers	1	Table 4-2
		Age	2	Figure 4-1
		Loading	2	Table 4-3
De-Rating		Livefront	70%	

4.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Pad Mounted 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 failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

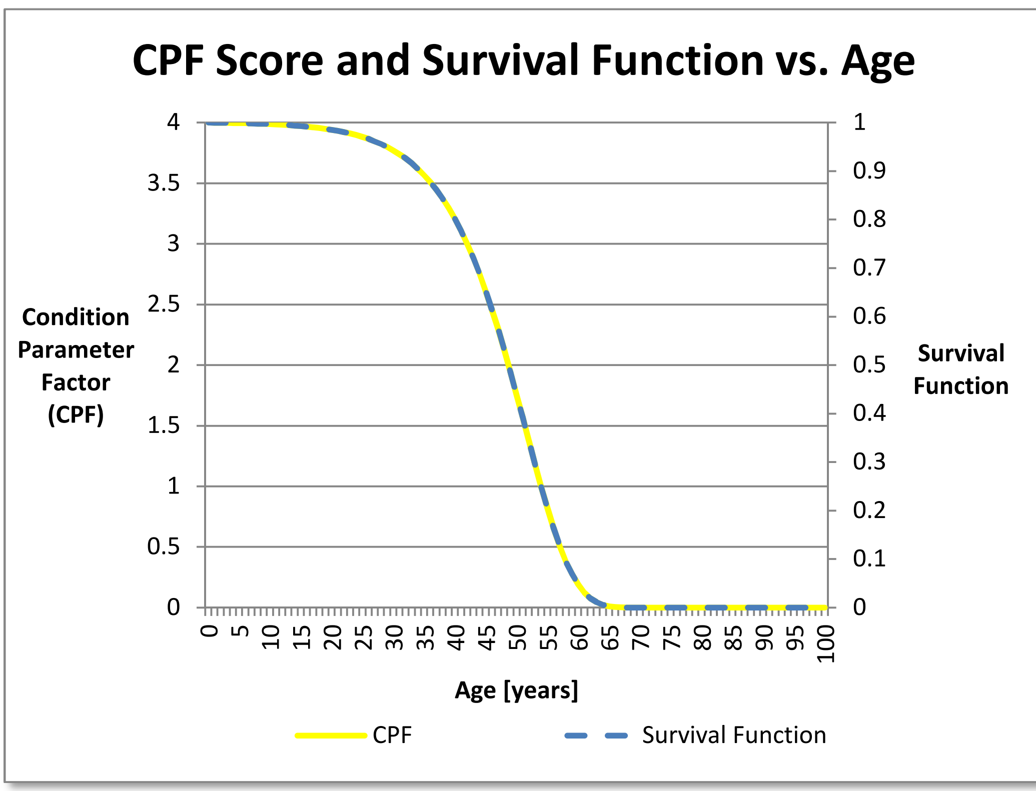


Figure 4-1 Pad Mounted Transformers Age Condition Criteria

Number of Customers

Table 4-2 Pad Mounted Transformers Number of Customers Description and Score

Number of Customers		Score
Transformer Size > 100 kVA	Transformer Size <= 100 kVA	
0-9	0-9	4
10-19	10-14	3
20-39	15-19	2
40+	20+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating}$$

Table 4-3 Pad Mounted Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

Okay or Not Okay

Table 4-4 Pad Mounted Transformers Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

4.2 Age Distribution

The age distribution is shown in the figure below. Age was available for only 78% of the population. The average age was found to be 14 years.

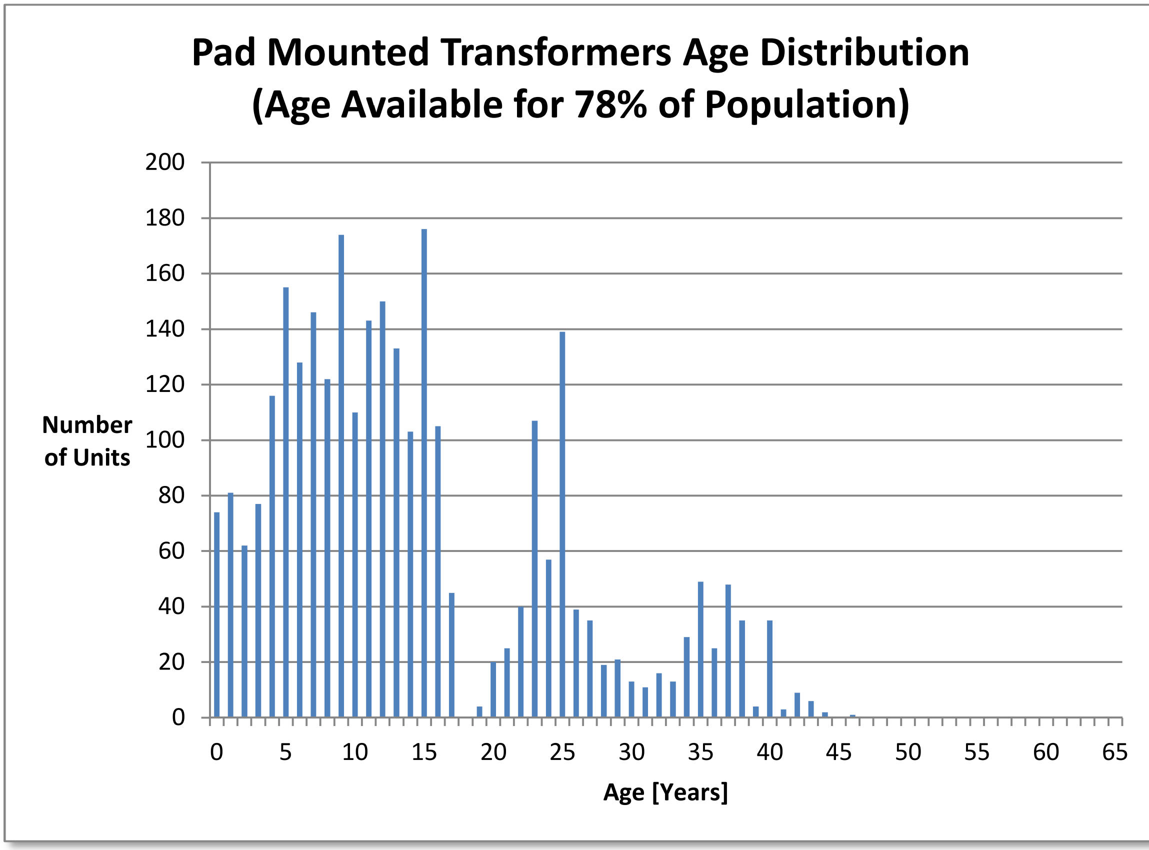


Figure 4-2 Pad Mounted Transformers Age Distribution

4.3 Health Index Results

There are 3722 in-service Pad Mounted Transformers at GHESI. There were 3722 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 88%. Approximately 2% of the units were found to be in poor condition.

The Health Index Results are as follows:

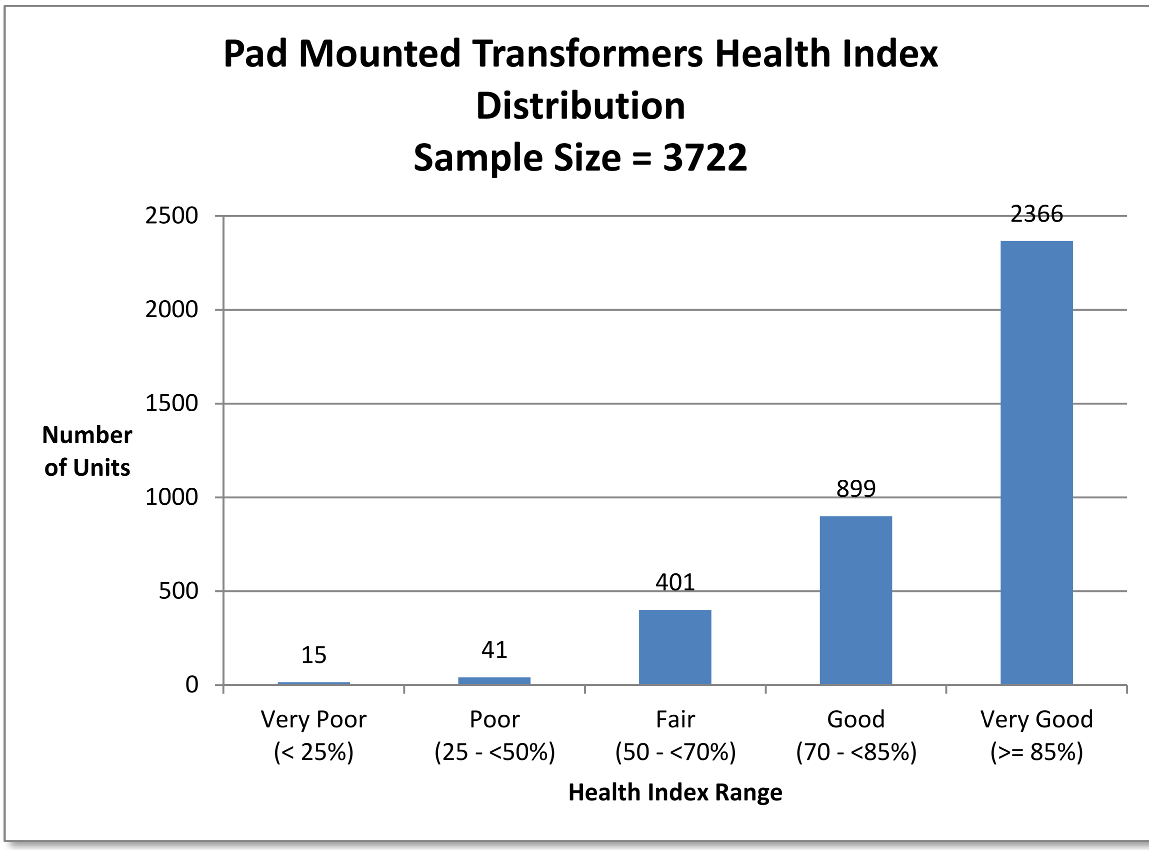


Figure 4-3 Pad Mounted Transformers Health Index Distribution (Number of Units)

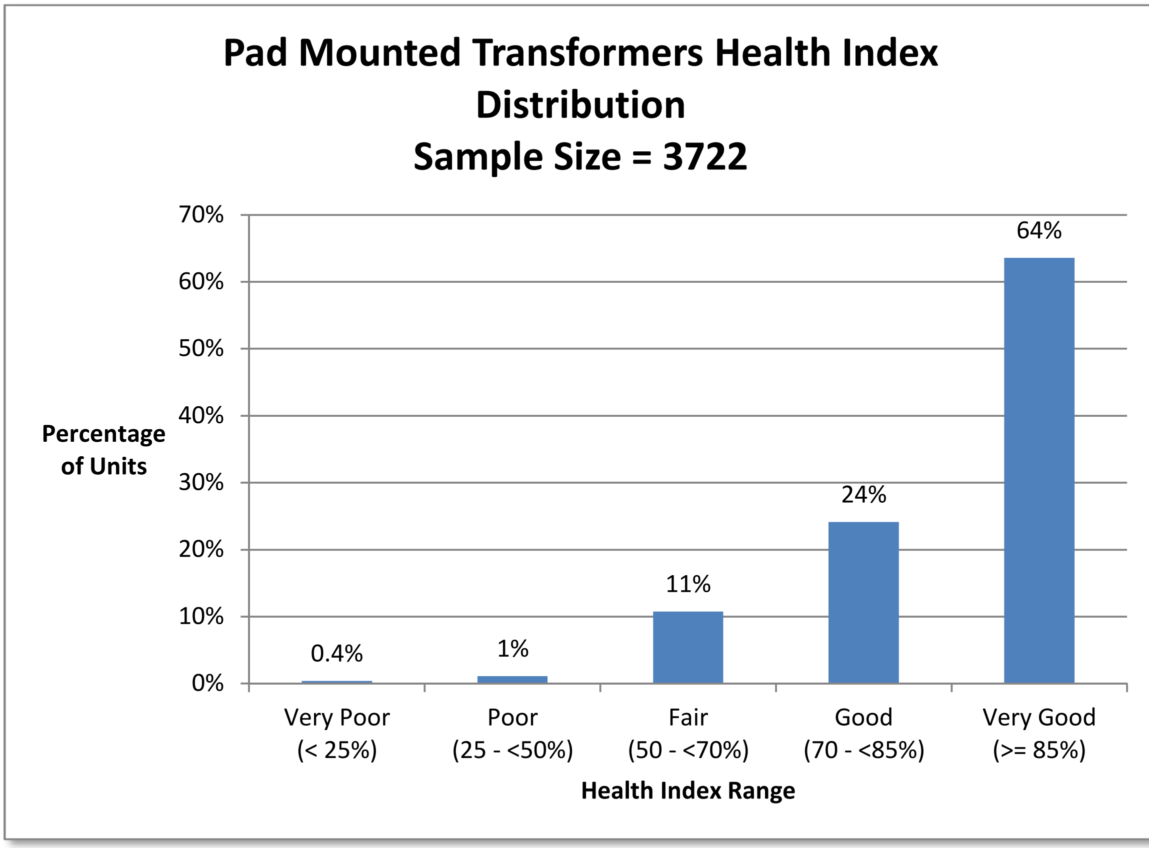


Figure 4-4 Pad Mounted Transformers Health Index Distribution (Percentage of Units)

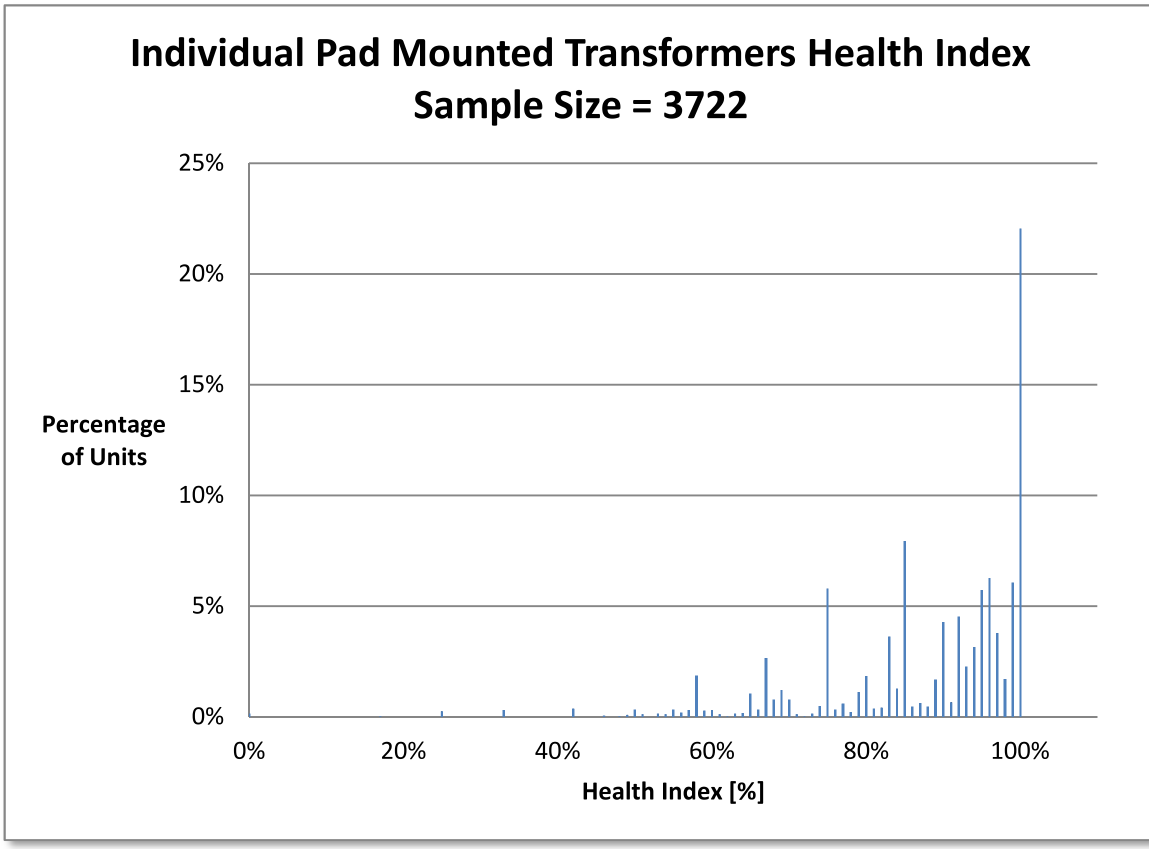


Figure 4-5 Pad Mounted Transformers Health Index Distribution by Value (Percentage of Units)

4.4 Condition-Based Flagged for Action Plan

As it is assumed that Pad Mounted Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

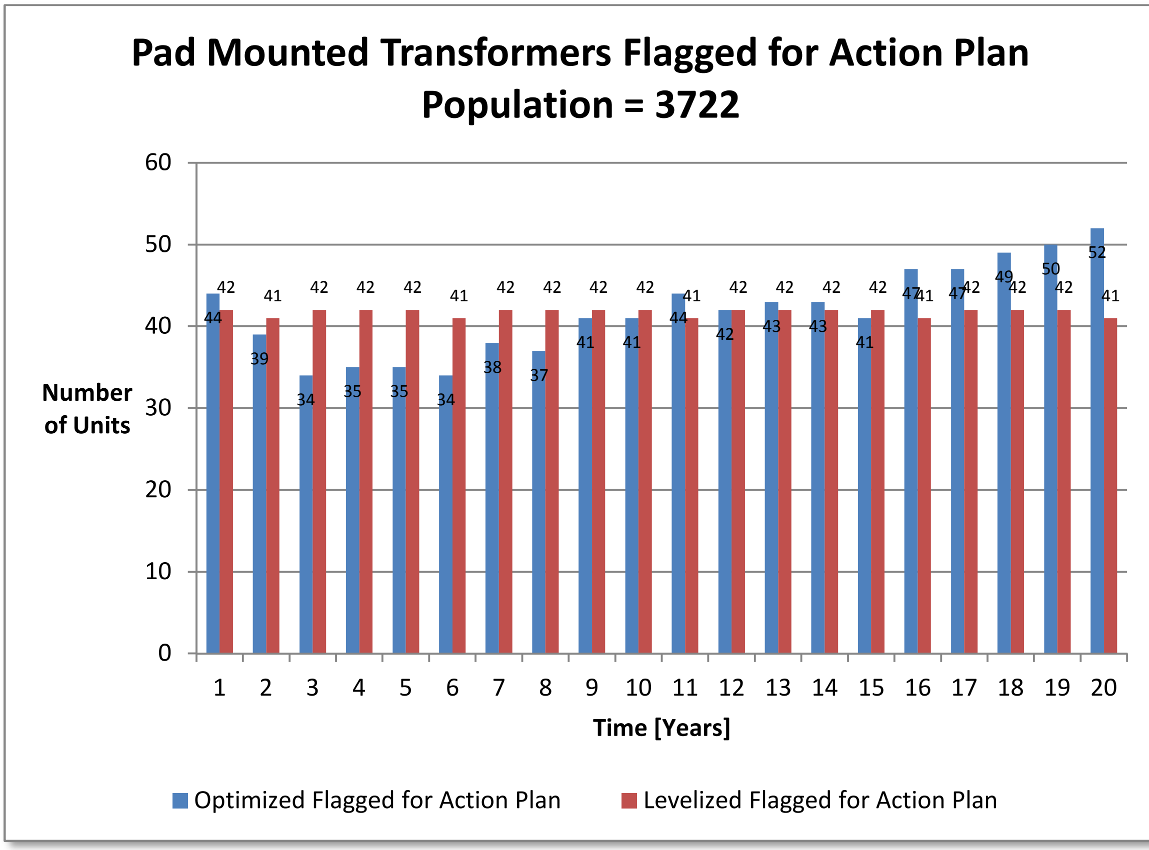


Figure 4-6 Pad Mounted Transformers Condition-Based Flagged for Action Plan

4.5 Data Analysis

4.5.1 Data Gap

The data available for Pad Mounted Transformers are age, number of customers, loading, and inspection records. No data gaps were identified.

4.5.2 Data Availability Distribution

Because not all units had inspection data available, the average DAI for Pad Mounted Transformers is 54%.

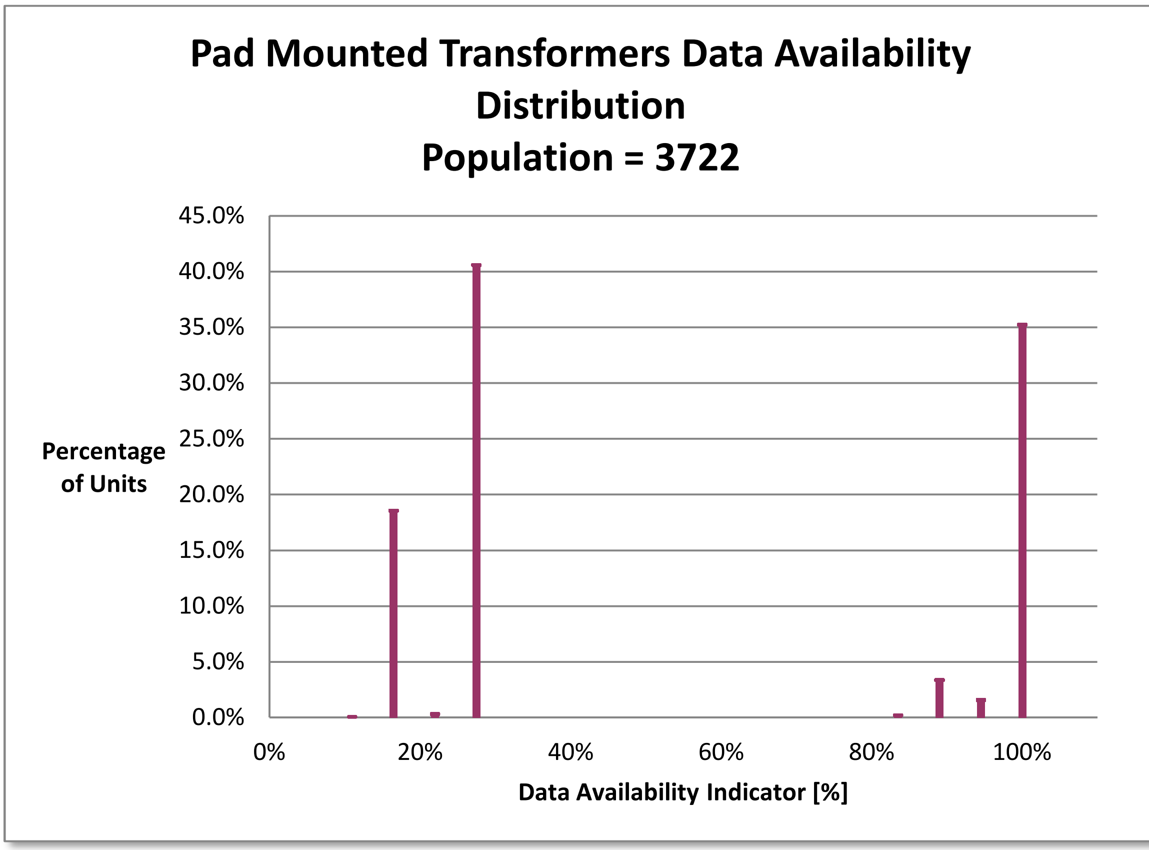


Figure 4-7 Pad Mounted Transformers Data Availability Distribution

5 Submersible Transformers

5.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Submersible Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Submersible Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	1	
Connection and Insulation	1	Oil Leak	1	
Service Record	1	Number of Customers	1	Table 5-2
		Age	2	Figure 5-1
		Loading	2	Table 5-3
		Overall	2	

5.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Submersible 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 35 and 40 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

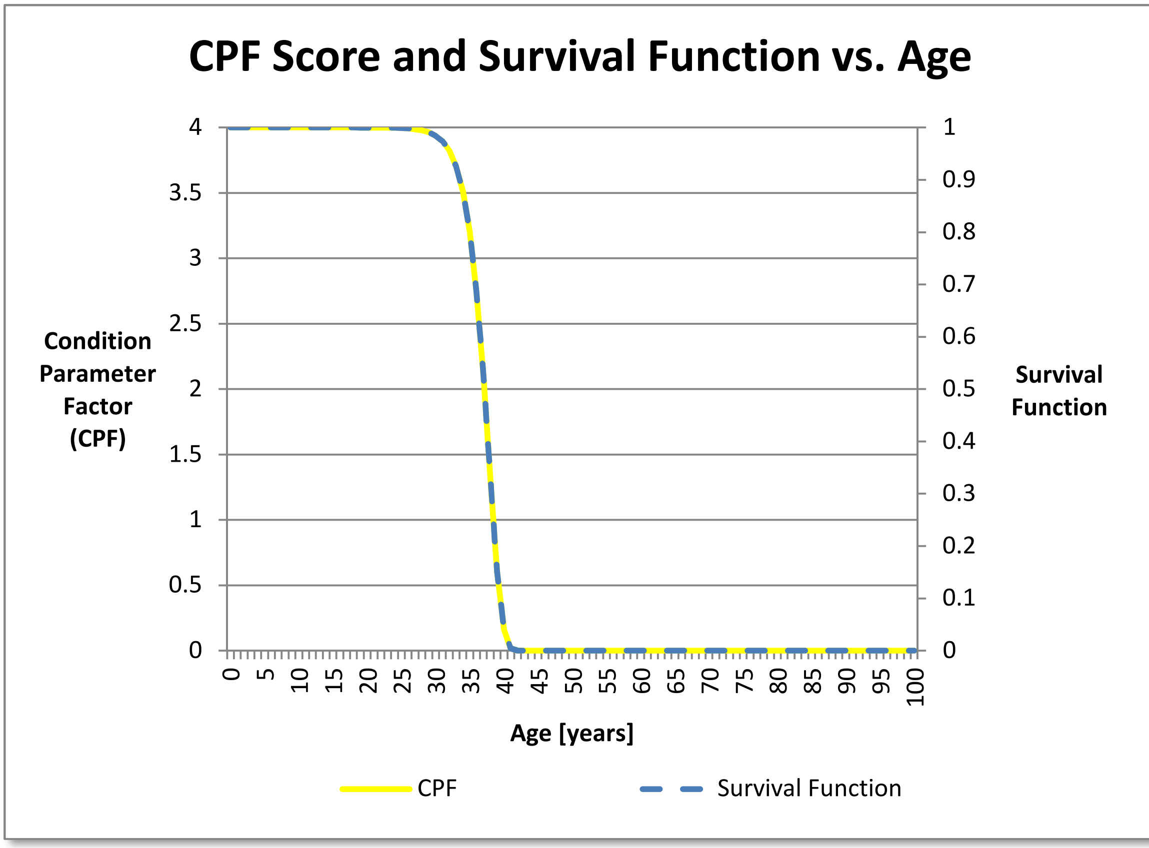


Figure 5-1 Submersible Transformers Age Condition Criteria

Number of Customers

Table 5-2 Submersible Transformers Number of Customers Description and Score

Number of Customers		Score
Transformer Size > 100 kVA	**Transformer Size <= 100 kVA**	
0-9	0-9	4
10-19	10-14	3
20-39	15-19	2
40+	20+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating}$$

Table 5-3 Submersible Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

5.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 48% of the population. The average age was found to be 14 years.

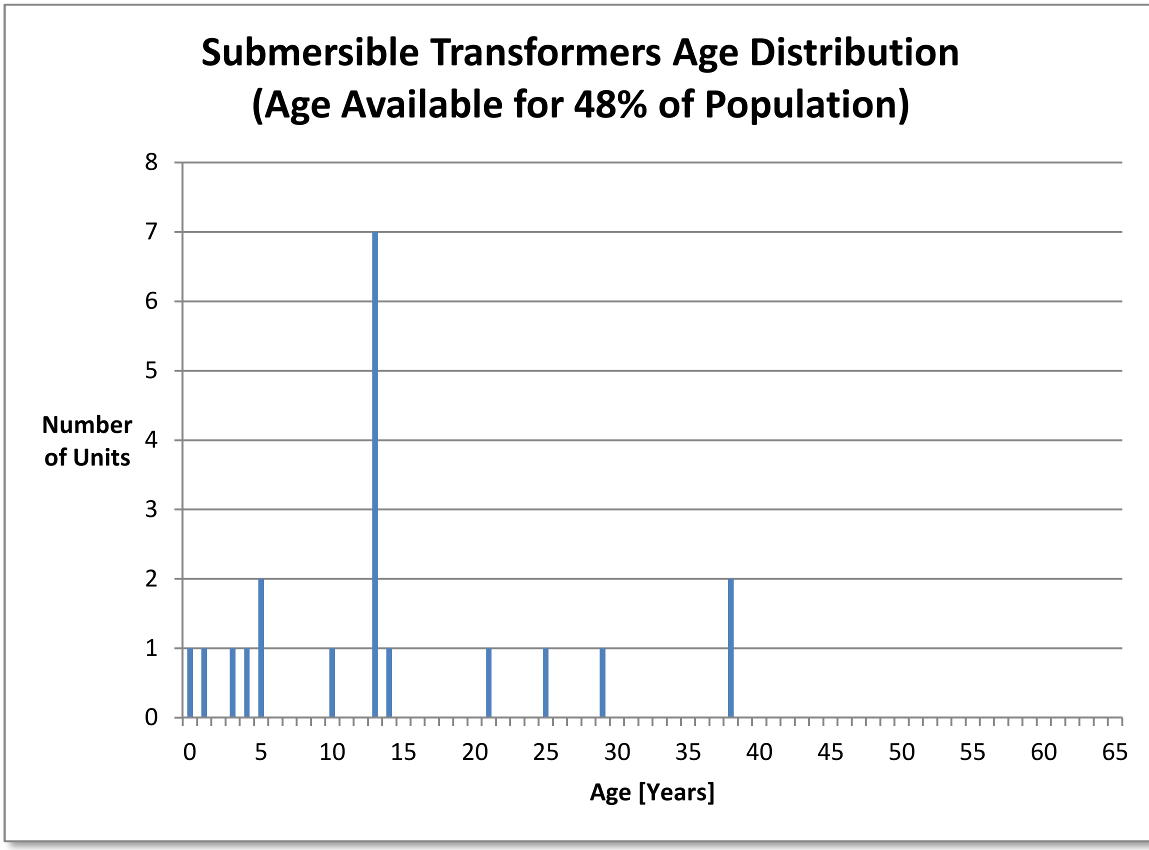


Figure 5-2 Submersible Transformers Age Distribution

5.3 Health Index Results

There are 42 in-service Submersible Transformers at GHESI. There were 42 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 90%. Approximately 2% of the units were found to be in poor condition.

The Health Index Results are as follows:

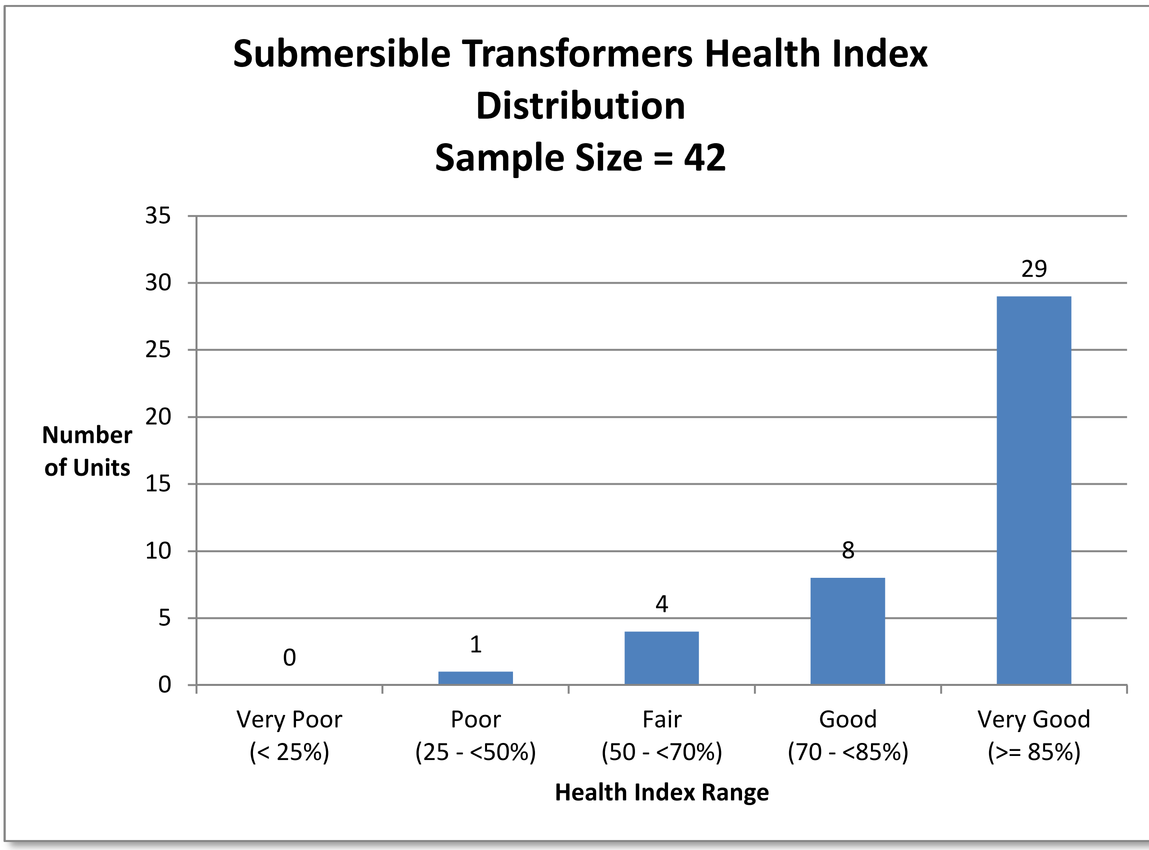


Figure 5-3 Submersible Transformers Health Index Distribution (Number of Units)

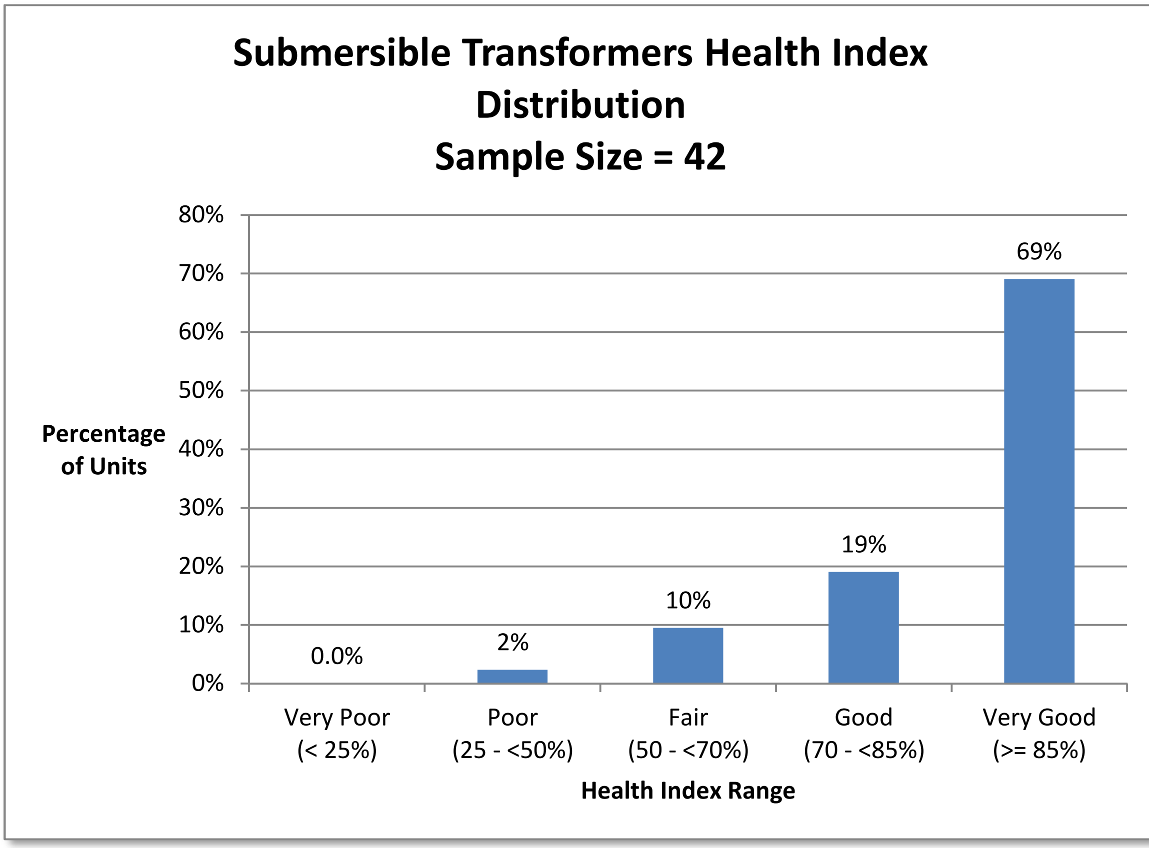


Figure 5-4 Submersible Transformers Health Index Distribution (Percentage of Units)

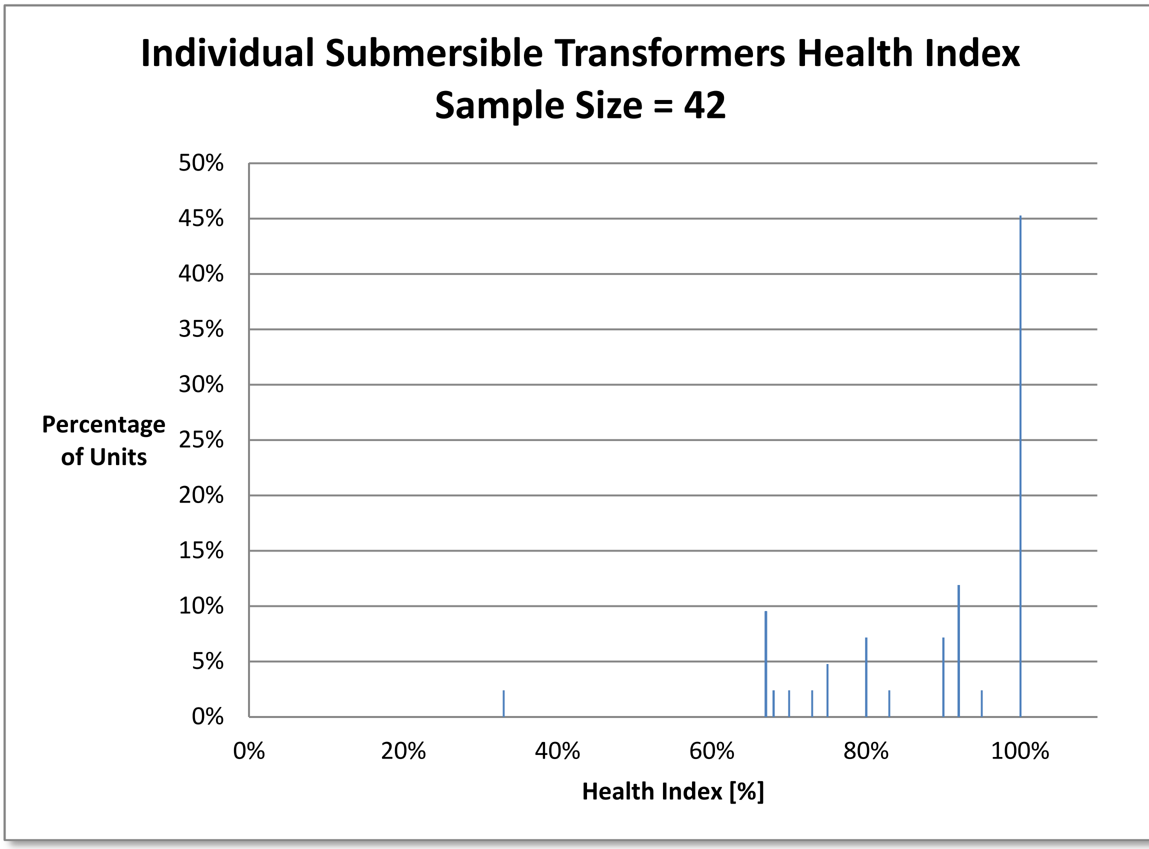


Figure 5-5 Submersible Transformers Health Index Distribution by Value (Percentage of Units)

5.4 Condition-Based Flagged for Action Plan

As it is assumed that Submersible Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

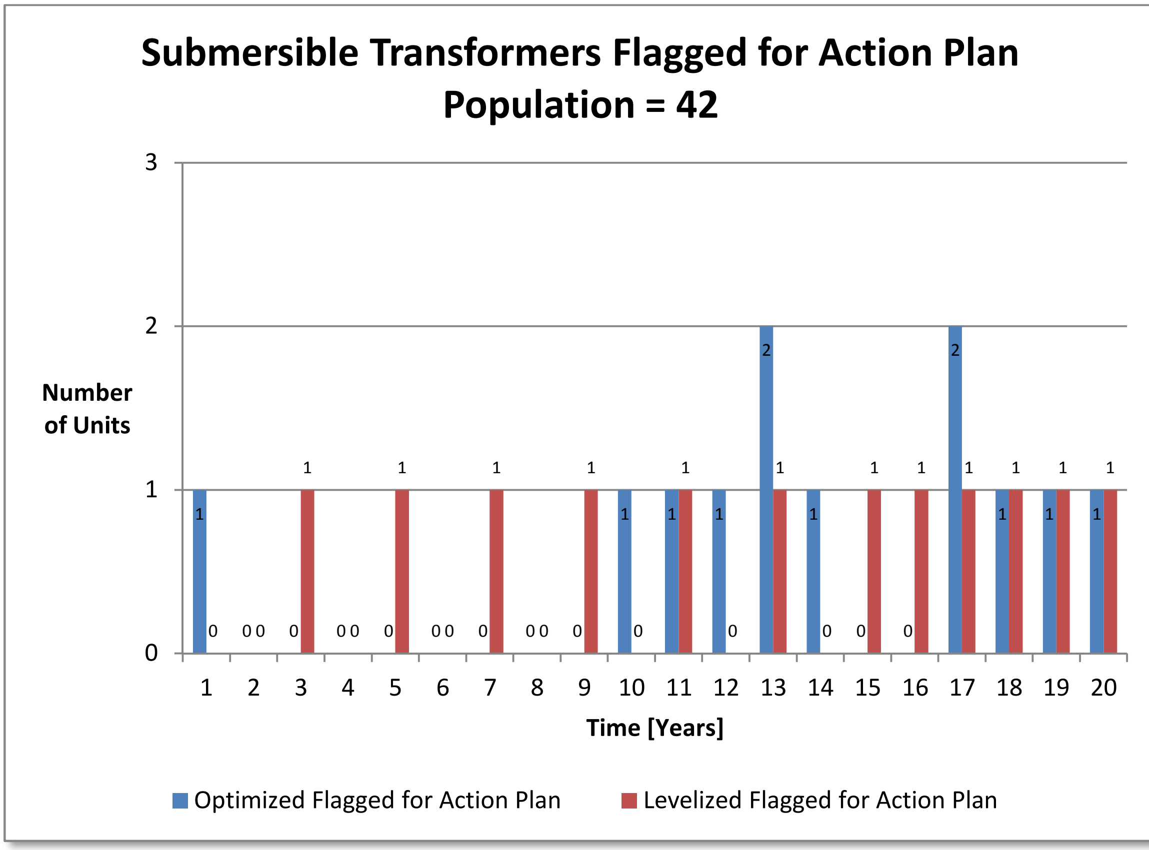


Figure 5-6 Submersible Transformers Condition-Based Flagged for Action Plan

5.5 Data Analysis

5.5.1 Data Gap

The data available for Submersible Transformers includes age, number of customers, and loading. The data gaps, which are mainly from inspections, are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Operation record

5.5.2 Data Availability Distribution

Because inspection data was not available, the average DAI for Submersible Transformers is 19%.

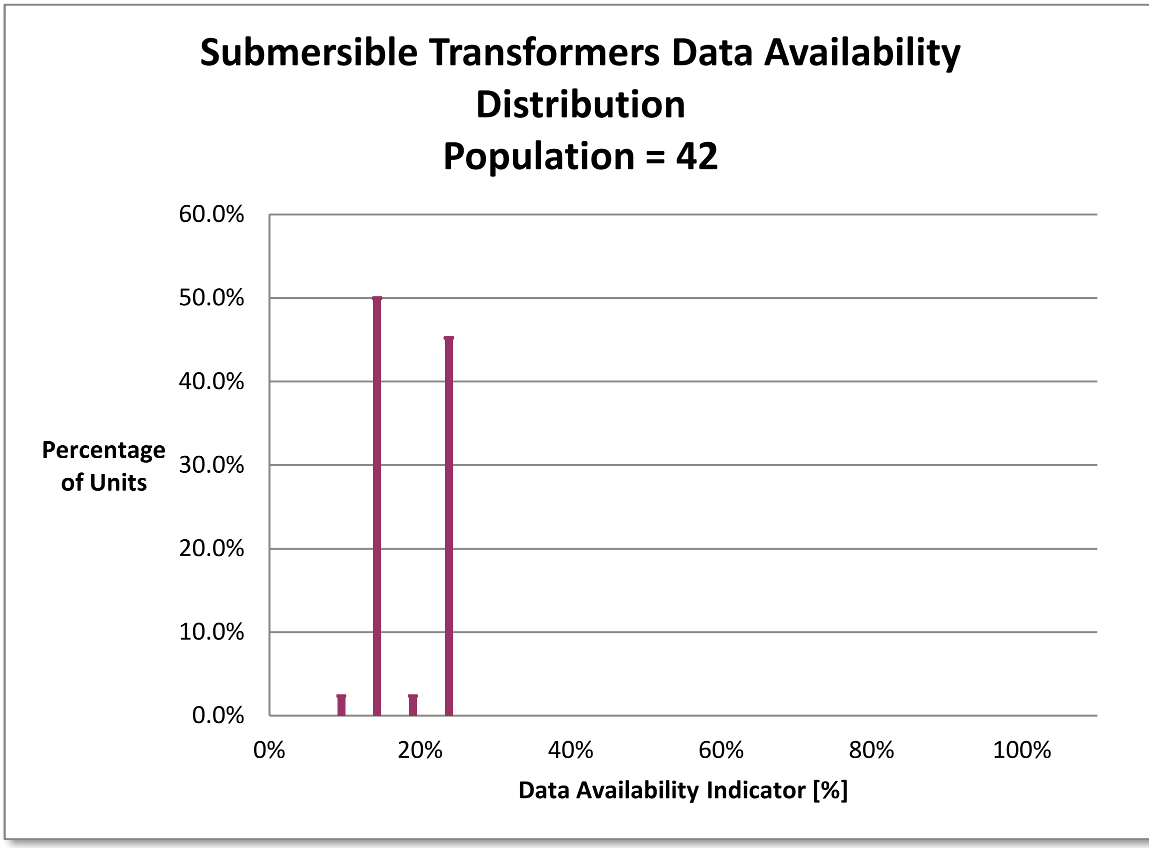


Figure 5-7 Submersible Transformers Data Availability Distribution

6 Vault Transformers

6.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Vault Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Vault Transformers Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	7	Corrosion	3	Table 6-4
		Access	1	Table 6-4
		Housekeeping	5	Table 6-4
Connection and Insulation	5	Oil Leak	2	Table 6-4
		Grounding	1	Table 6-4
		Elbow	3	Table 6-4
		Stress Cone	3	Table 6-4
		Bushing	3	Table 6-4
Service Record	**5**	Overall Condition	2	Table 6-4
		Number of Customers	1	Table 6-2
		Age	2	Figure 6-1
		Loading	2	Table 6-3

6.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Vault 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 35 and 40 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

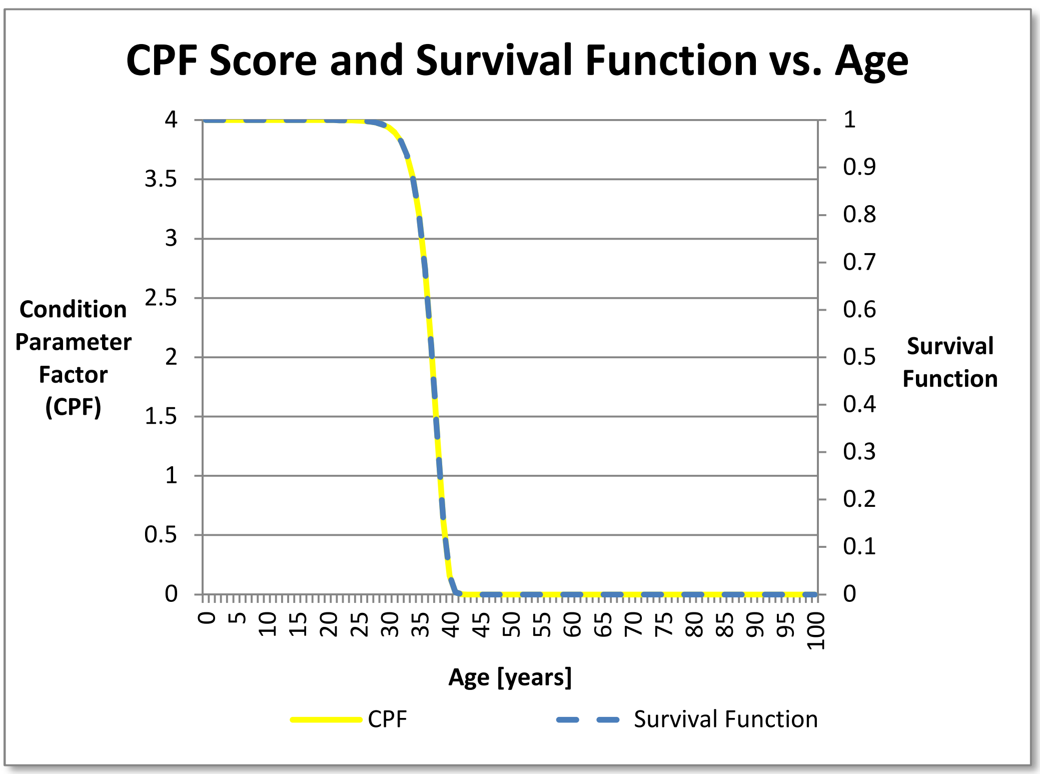


Figure 6-1 Vault Transformers Age Condition Criteria

Number of Customers

Table 6-2 Vault Transformers Number of Customers Description and Score

Number of Customers	Score
0-9	4
10-19	3
20-39	2
40+	0

Transformer Service Record

The *load factor* is the annual peak load of the distribution transformer divided by the nameplate rating.

$$\textit{Load Factor} = \frac{AnnualPeakLoad}{NameplateRating}$$

Table 6-3 Vault Transformers Loading Description and Score

Load Factor	Score
0-59%	4
60% - 79%	3
80% - 99%	2
100% - 119%	1
120%+	0

Okay or Not Okay

Table 6-4 Vault Transformers Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

6.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 70% of the population. The average age was found to be 23 years.

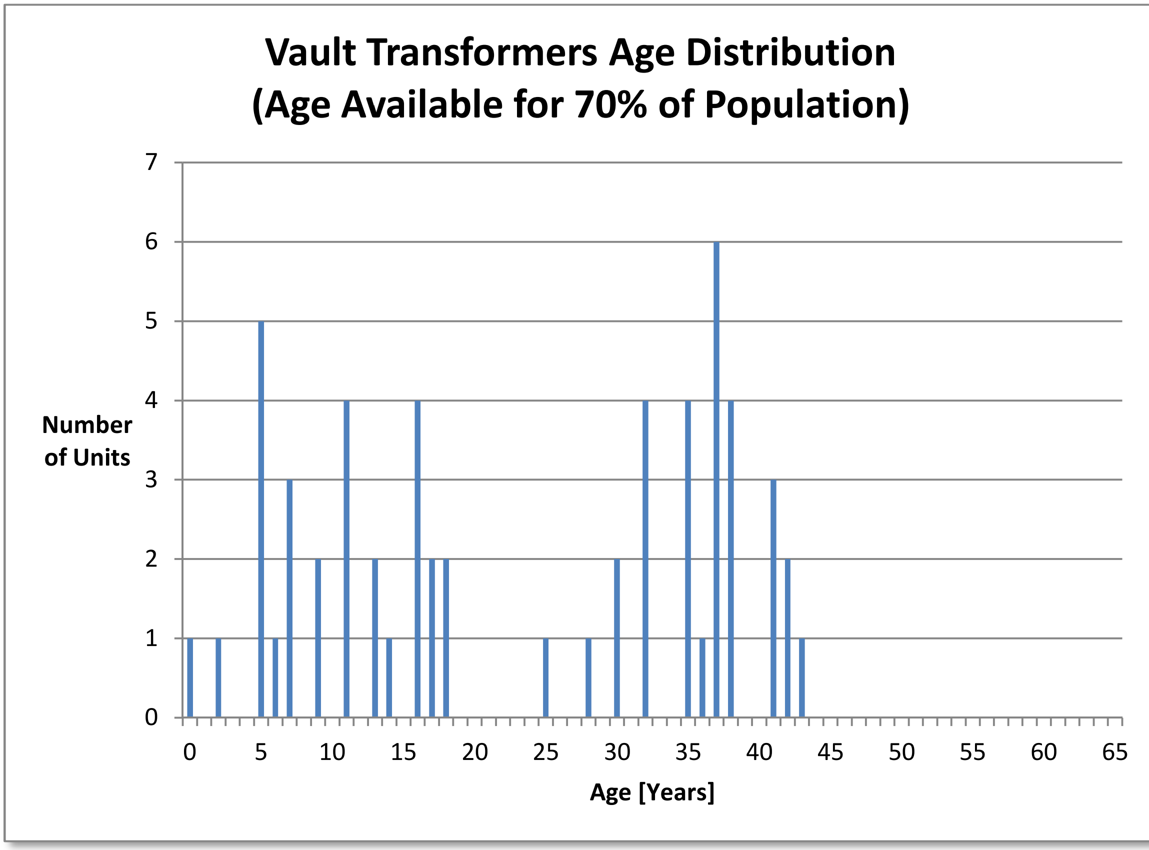


Figure 6-2 Vault Transformers Age Distribution

6.3 Health Index Results

There are 82 in-service Vault Transformers at GHESI. There were 82 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 90%. Approximately 1% of the units were found to be in poor condition.

The Health Index Results are as follows:

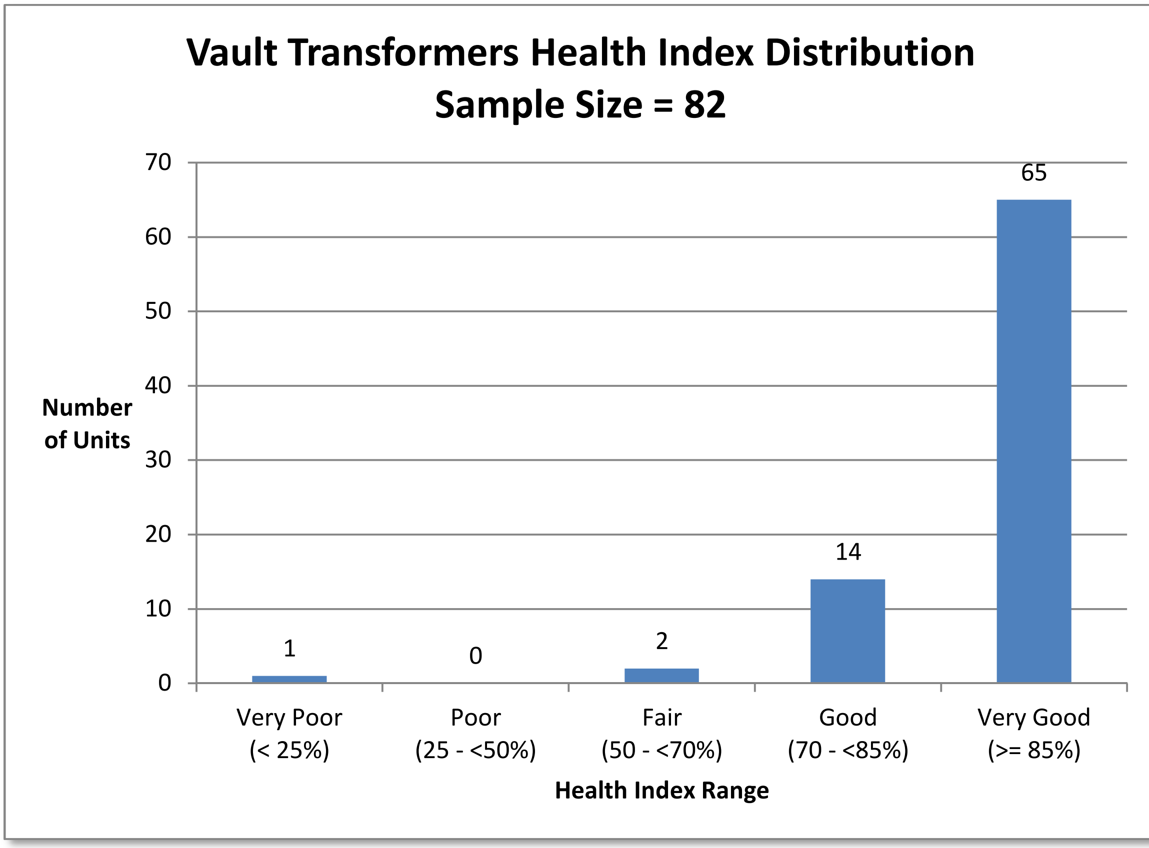


Figure 6-3 Vault Transformers Health Index Distribution (Number of Units)

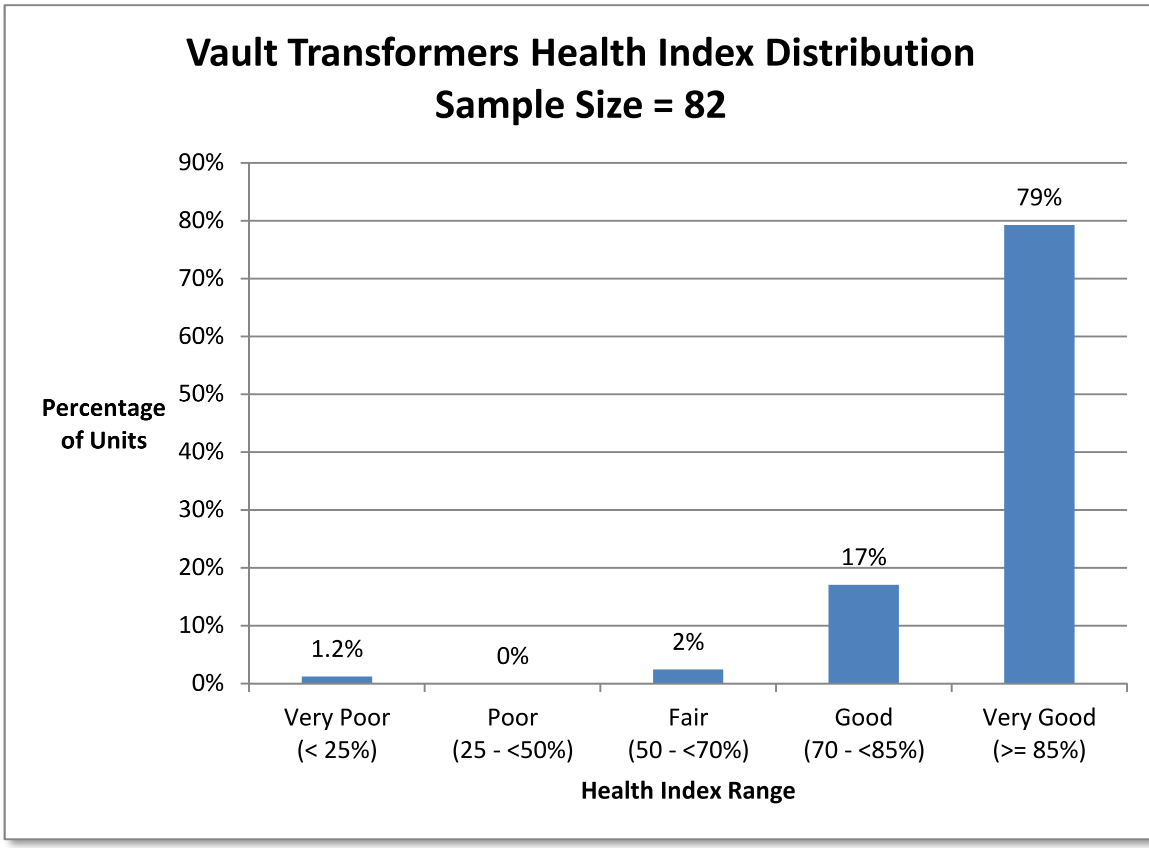


Figure 6-4 Vault Transformers Health Index Distribution (Percentage of Units)

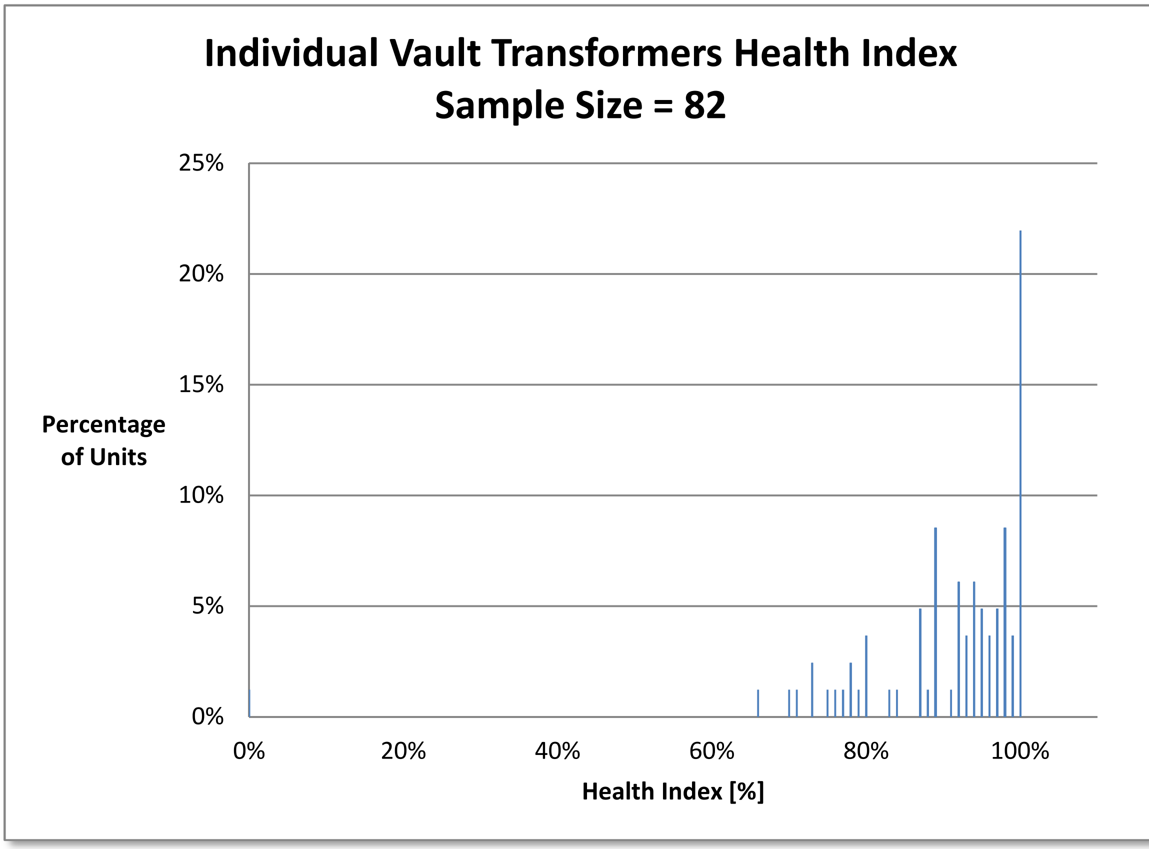


Figure 6-5 Vault Transformers Health Index Distribution by Value (Percentage of Units)

6.4 Condition-Based Flagged for Action Plan

As it is assumed that Vault Transformers are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

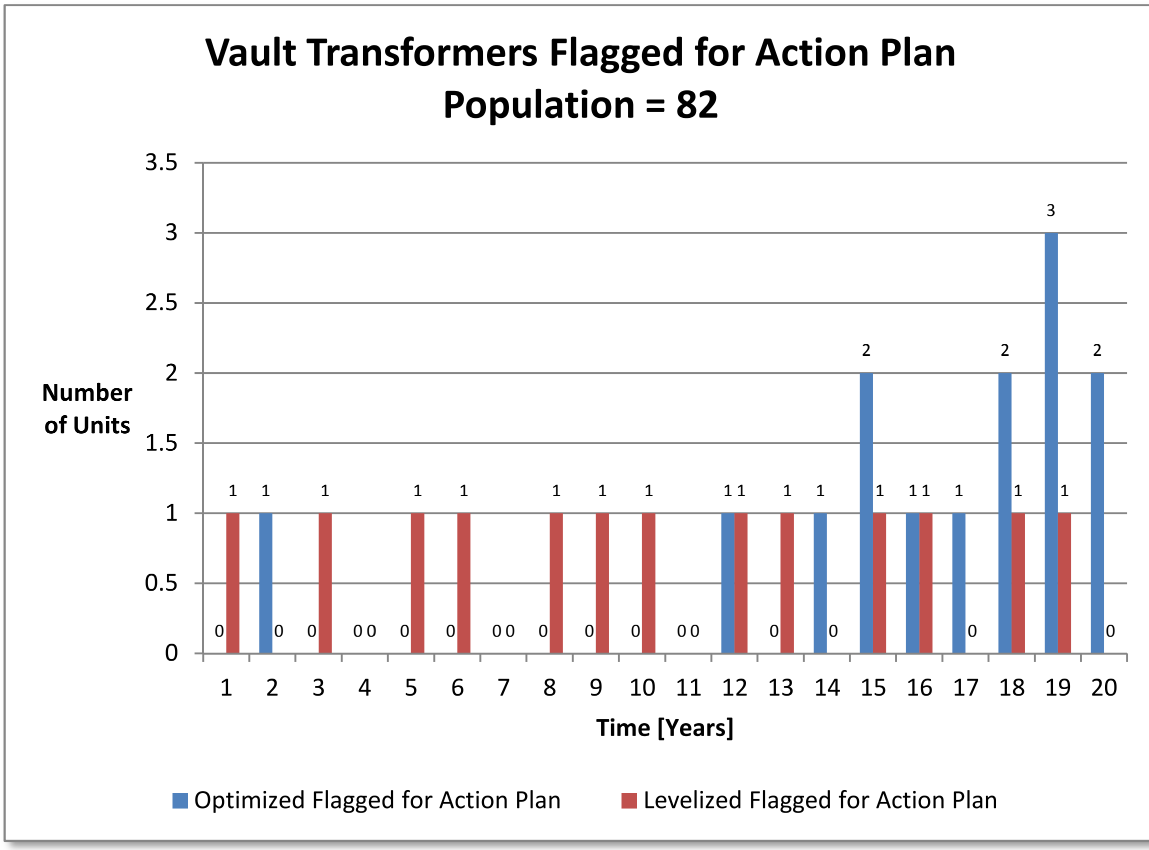


Figure 6-6 Vault Transformers Condition-Based Flagged for Action Plan

6.5 Data Analysis

6.5.1 Data Gap

The data available for Vault Transformers includes age, loading, number of customers, and inspection records. There are no data gaps for this asset category.

6.5.2 Data Availability Distribution

The average DAI for Vault Transformers is 95%.

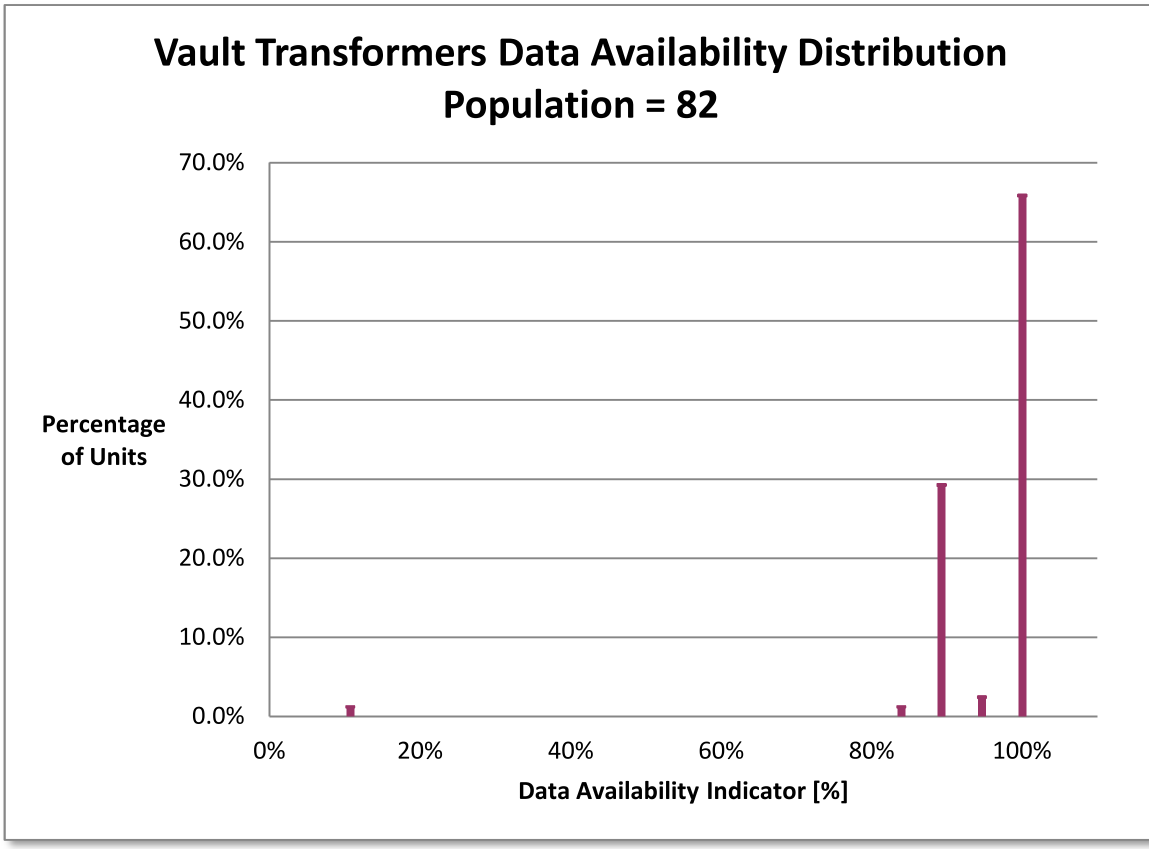


Figure 6-7 Vault Transformers Data Availability Distribution

7 Load Interrupting Switches

7.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Load Interrupting Switches (LIS). The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 Load Interrupting Switches Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Operating Mechanism	13	Mechanism, Switch Mounting	1	
Arc Extinction	4	Arc Horn, Interrupter	1	
Insulation	2	Insulator	1	
Switch	6	Switch	1	
Maintenance	1	Maintained	1	Table 7-2
Service Record	9	Age	1	Figure 7-2
		Number of Operations*	1	Table 7-3

*This parameter refers to the number of operations in the past 5 years (not the lifetime total operations)

7.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Load Interrupting Switches 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 50 and 60 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

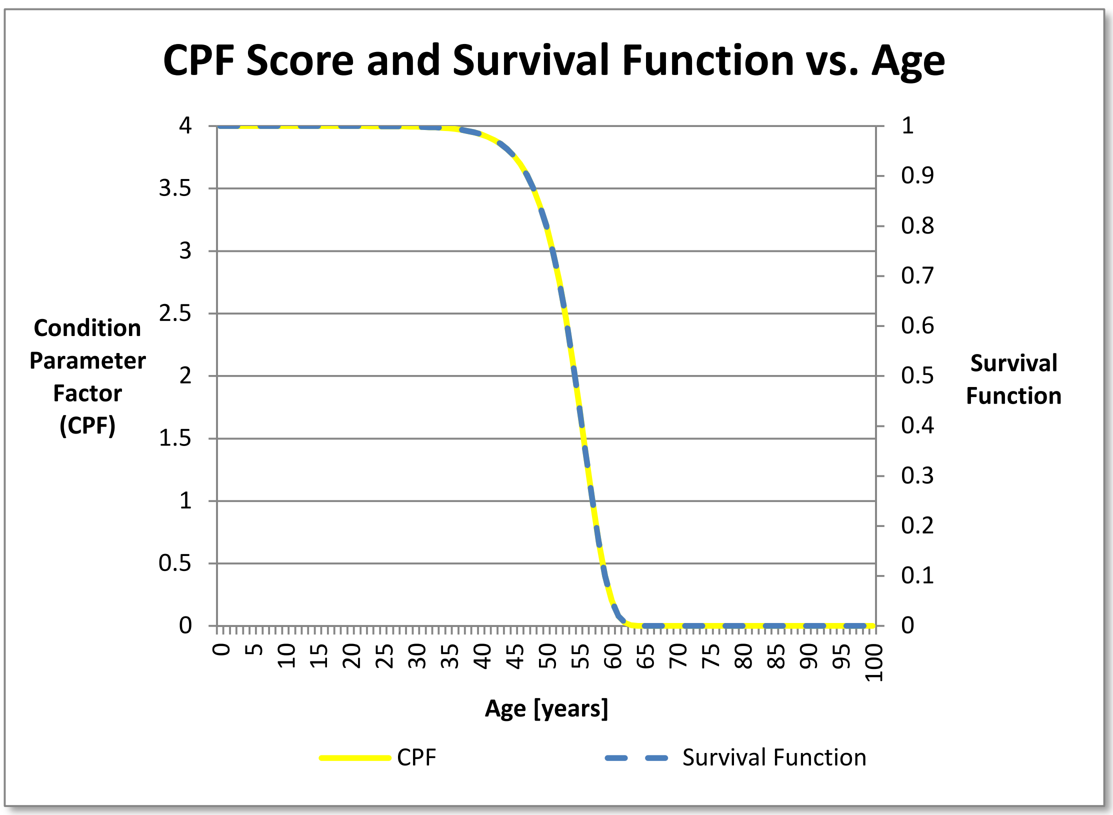


Figure 7-1 Load Interrupting Switches Age Condition Criteria

Maintenance Record

Table 7-2 Load Interrupting Switches Maintenance Record Description and Score

Recently Maintained	Score
NO	0
YES	4

Number of Operations

Table 7-3 Load Interrupting Switches Number of Operations Description and Score

Total Number of Operations (past 5 years)	Score
0*	3
1 – 4	4
5 - 9	3
10 - 19	2
20 - 29	1
30+	0

*If a unit has not been operated within the last 5 years it is unknown if the switch will operate as required. As such, the score is reduced to 3

7.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 13 years.

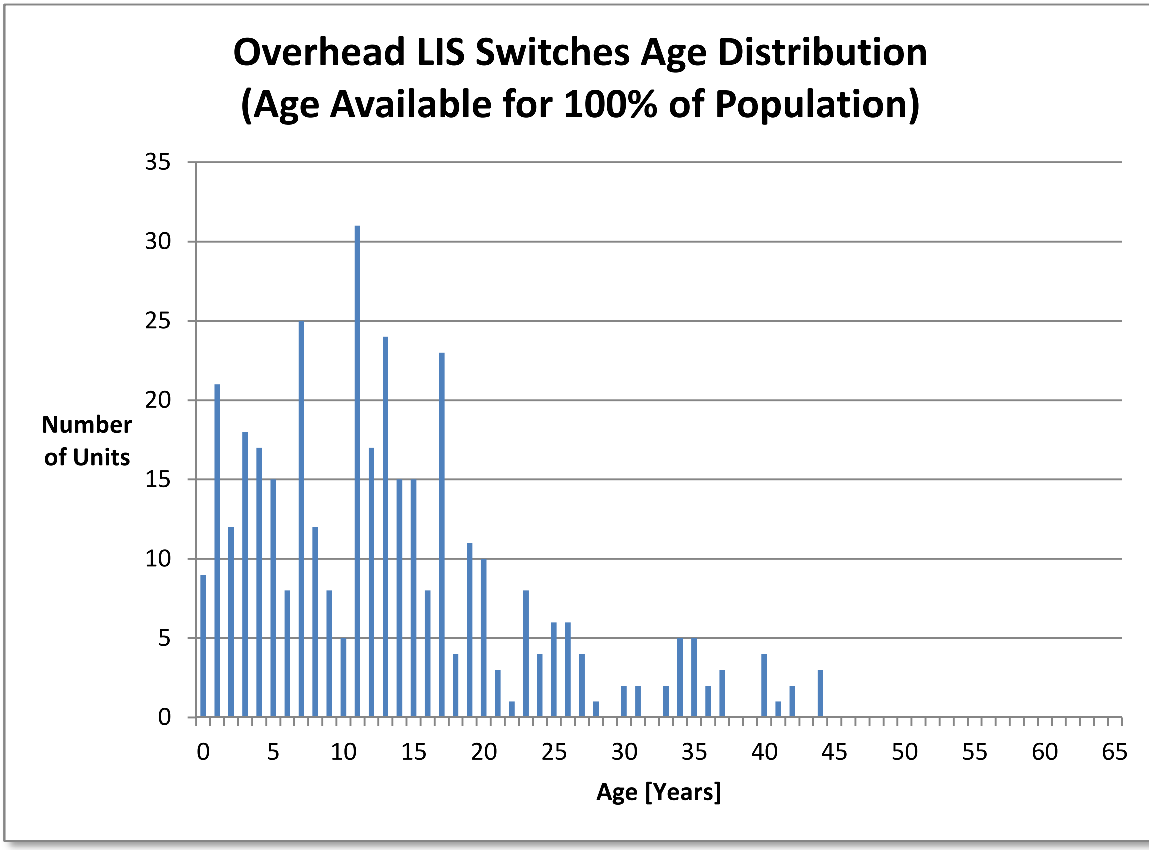


Figure 7-2 Load Interrupting Switches Age Distribution

7.3 Health Index Results

There are 372 in-service Load Interrupting Switches at GHESI. There were 372 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 86%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

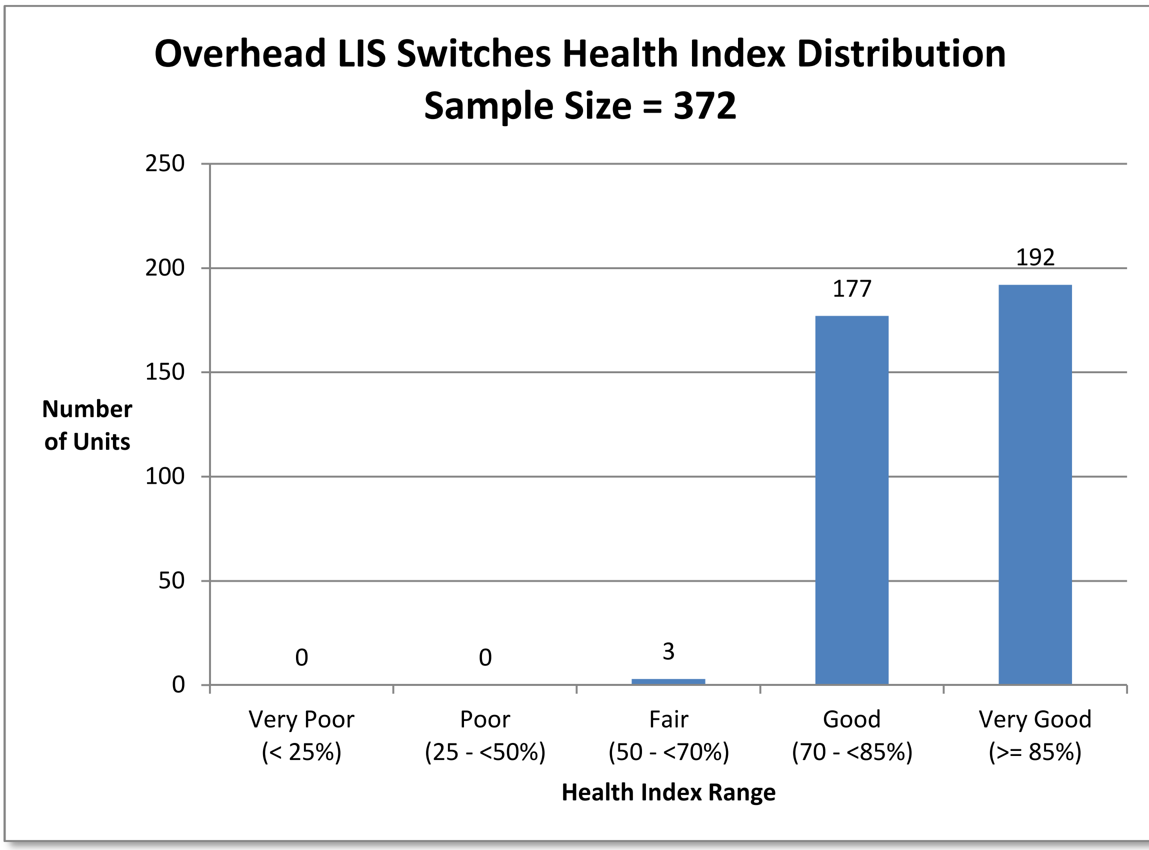


Figure 7-3 Load Interrupting Switches Health Index Distribution (Number of Units)

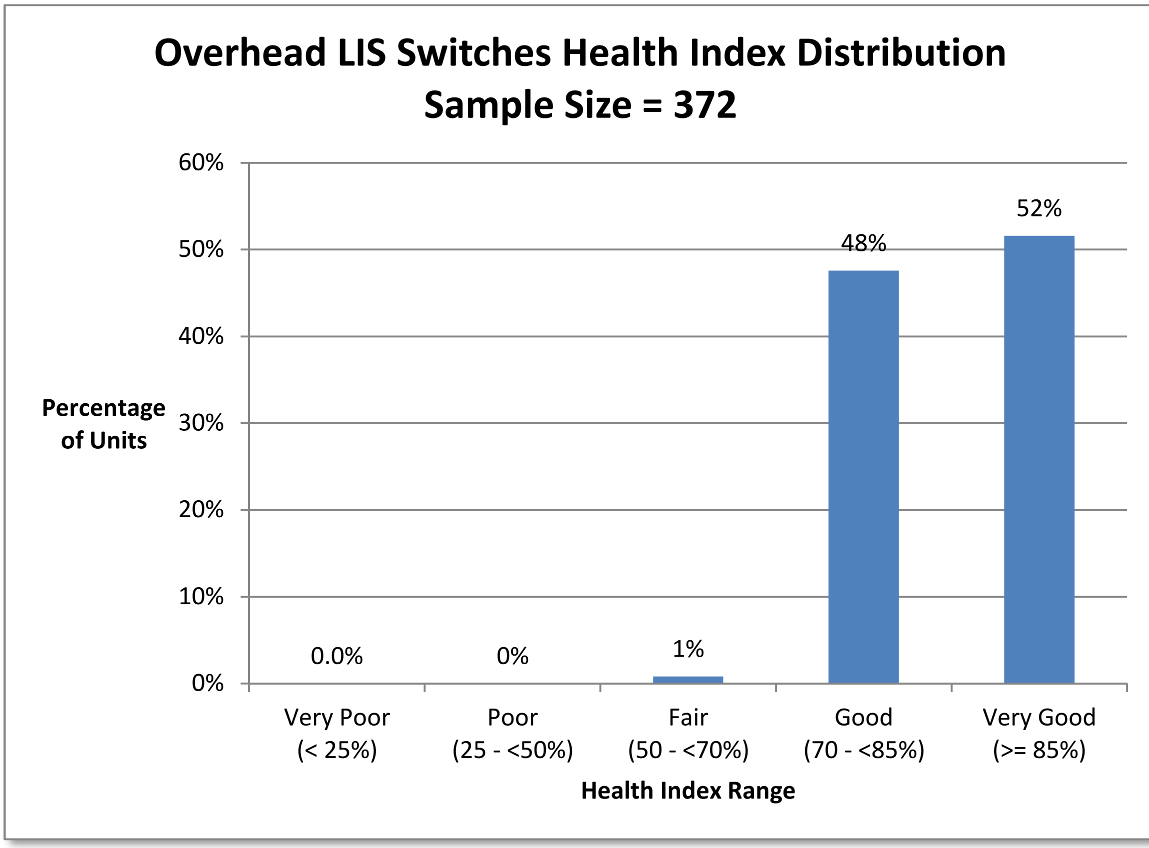


Figure 7-4 Load Interrupting Switches Health Index Distribution (Percentage of Units)

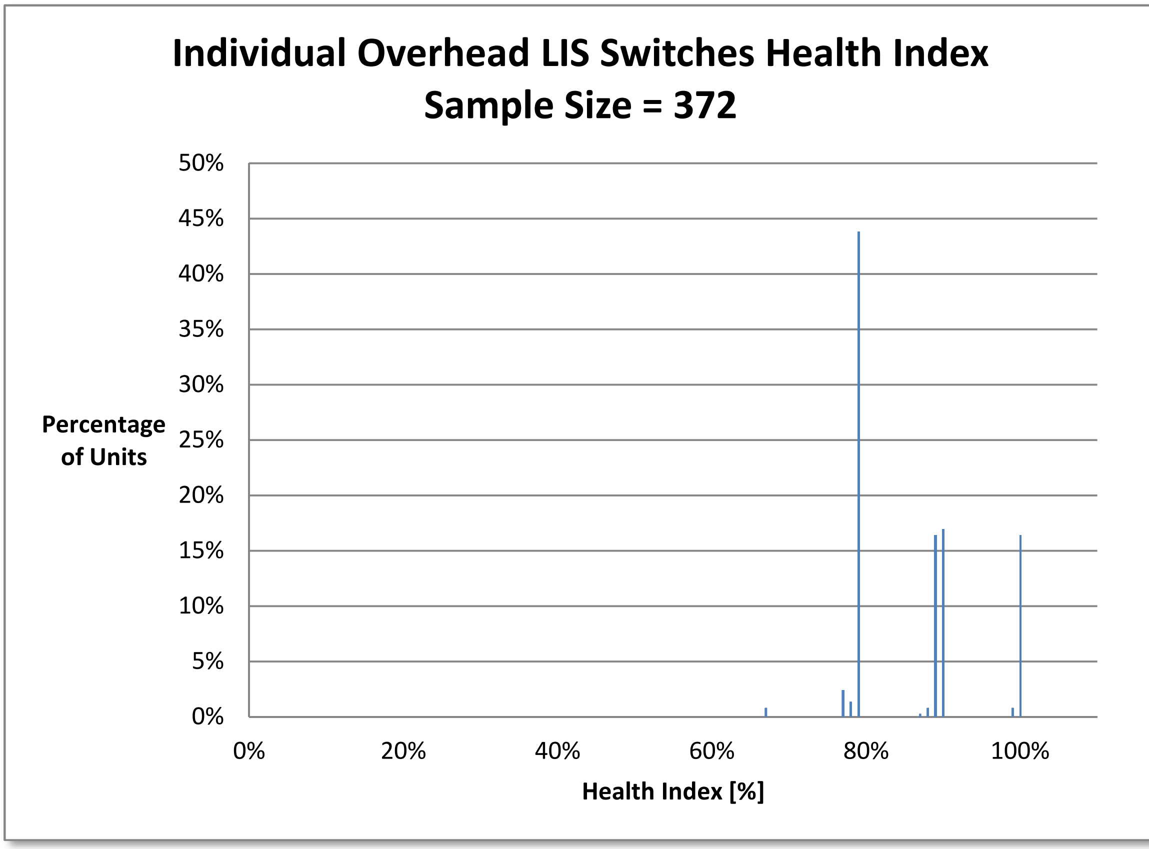


Figure 7-5 Load Interrupting Switches Health Index Distribution by Value (Percentage of Units)

7.4 Condition-Based Flagged for Action Plan

As it is assumed that Load Interrupting Switches are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

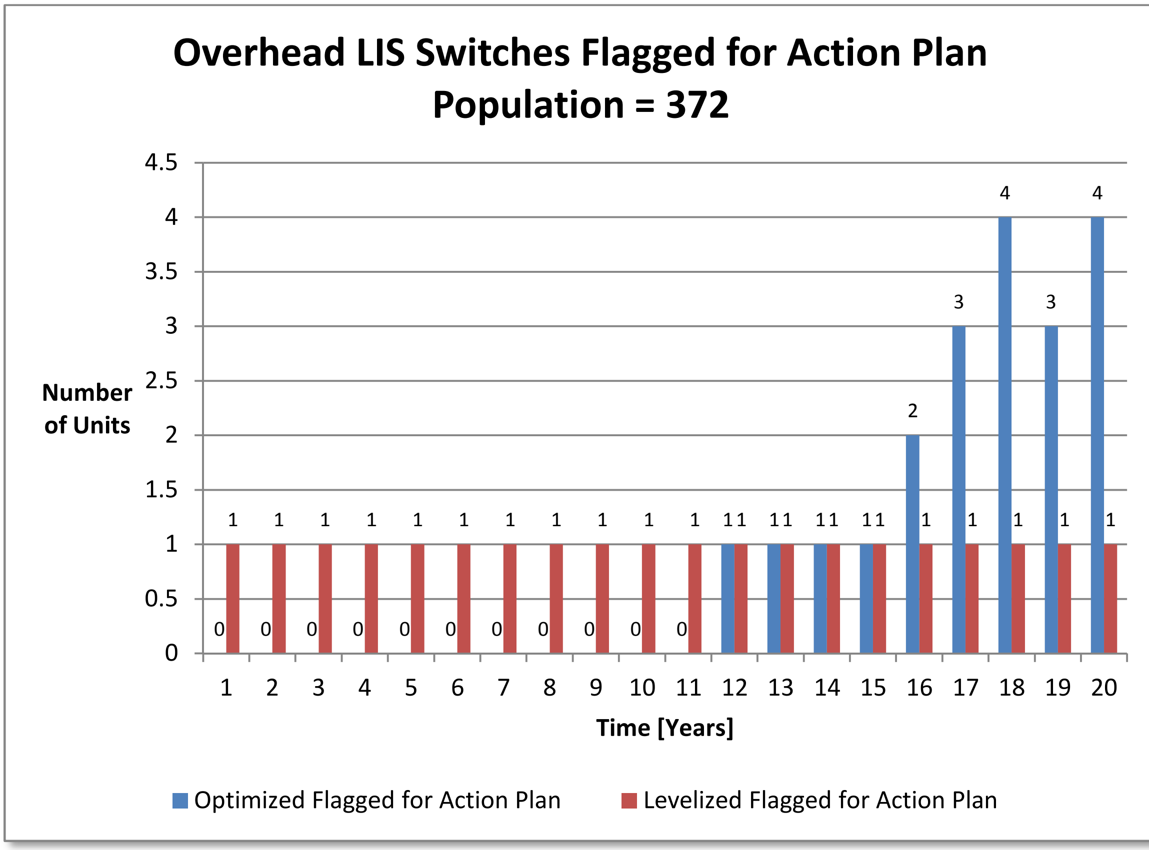


Figure 7-6 Load Interrupting Switches Condition-Based Flagged for Action Plan

7.5 Data Analysis

7.5.1 Data Gap

The data available for Load Interrupting Switches includes age, number of operations, and an indicator of whether the switch has been inspected or not. The data gaps, which are primarily from visual inspections, 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	**Switch**	☆☆☆	Blade	Blade condition	On-site visual inspection

7.5.2 Data Availability Distribution

Because no inspection data was available, the average DAI for Load Interrupting Switches is 28%.

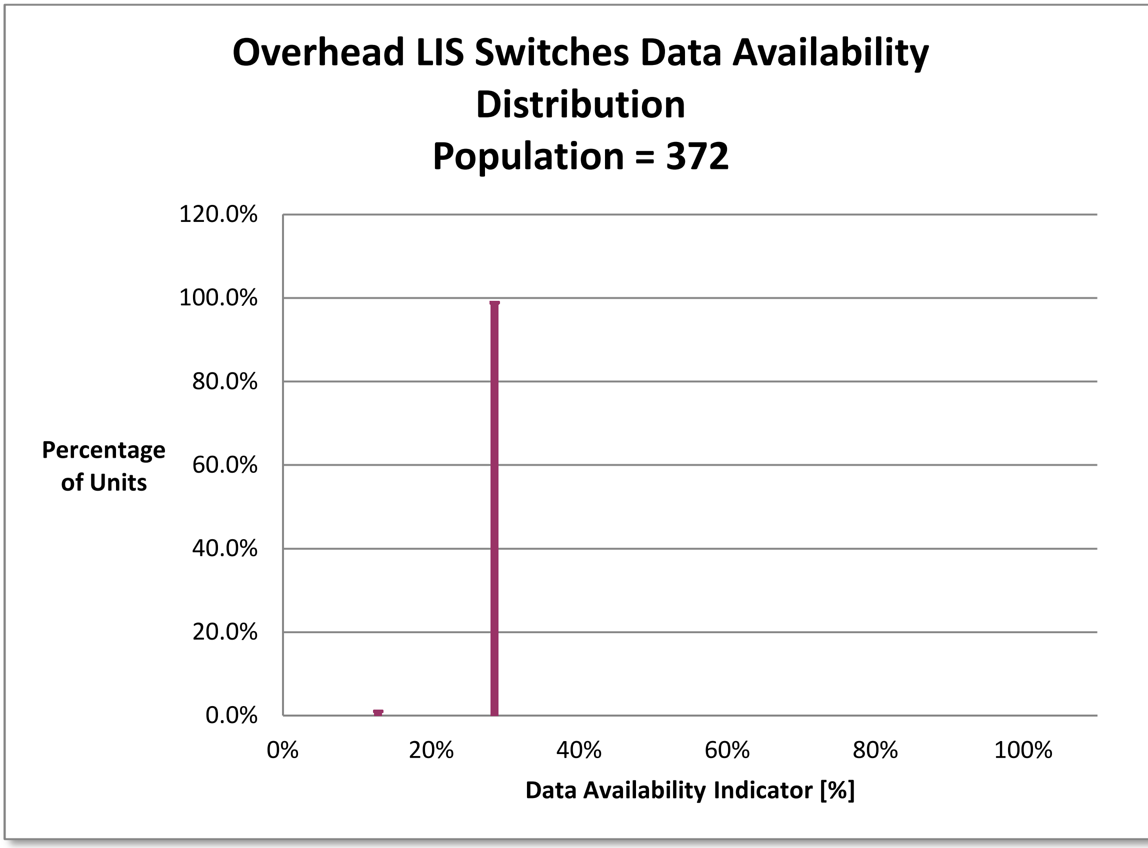


Figure 7-7 Load Interrupting Switches Data Availability Distribution

8 SCADA Switches

8.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI SCADA Switches. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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 SCADA Switches Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Operating Mechanism	13	Mechanism, Switch Mounting	1	
Arc Extinction	4	Arc Horn, Interrupter	1	
Insulation	2	Insulator	1	
Switch	6	Switch	1	
Maintenance	1	Maintained	1	Table 8-2
Service Record	9	Age	1	Figure 8-2
		Number of Operations*	1	Table 8-3

*This parameter refers to the number of operations in the past 5 years (not the lifetime total operations)

8.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for SCADA Switches 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 45 and 60 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

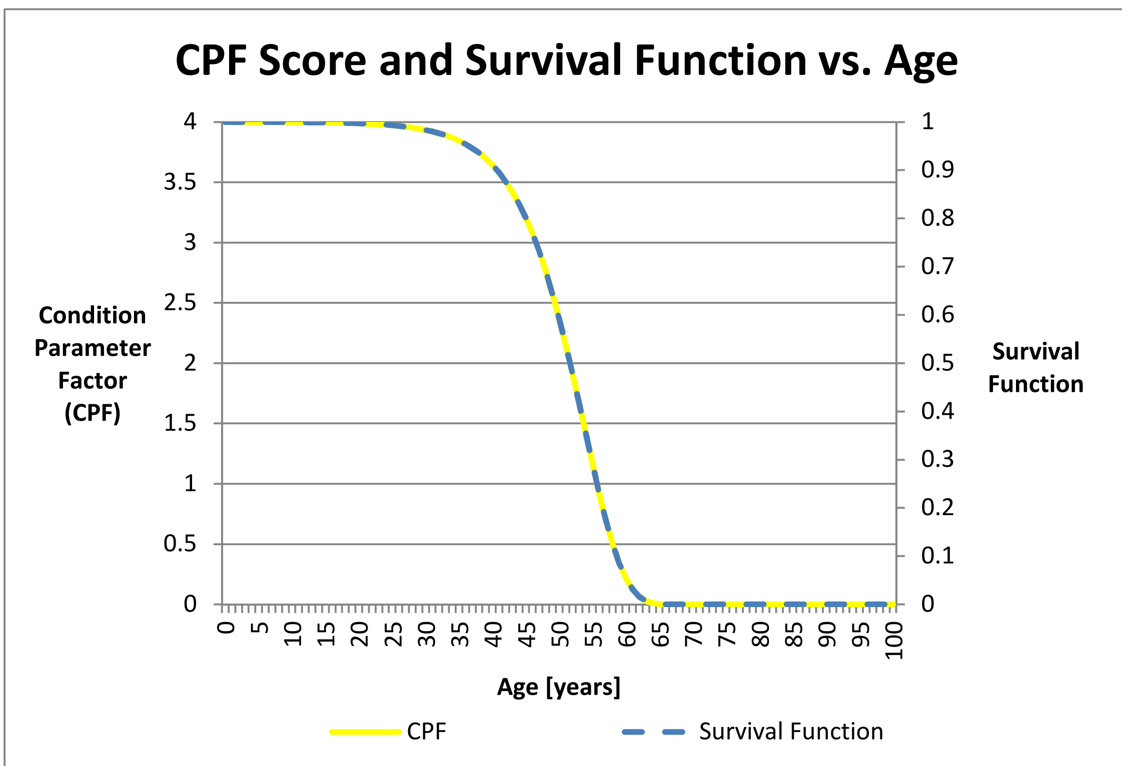


Figure 8-1 SCADA Switches Age Condition Criteria

Maintenance Record

Table 8-2 SCADA Switches Maintenance Record Description and Score

Recently Maintained	Score
NO	0
YES	4

Number of Operations

Table 8-3 SCADA Switches Number of Operations Description and Score

Total Number of Operations (past 5 years)	Score
0*	3
1 – 4	4
5 - 9	3
10 - 19	2
20 - 29	1
30+	0

*If a unit has not been operated within the last 5 years it is unknown if the switch will operate as required. As such, the score is reduced to 3

8.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 8 years.

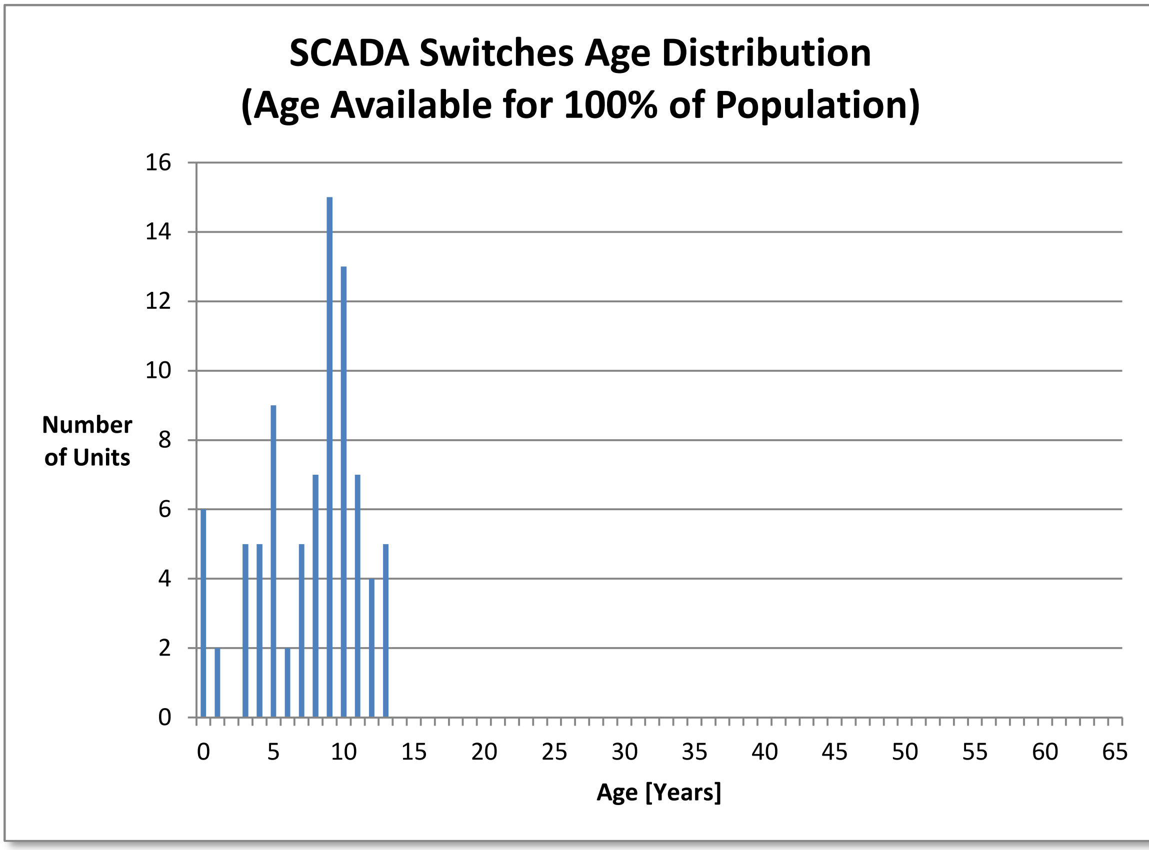


Figure 8-2 SCADA Switches Data Availability Distribution

8.3 Health Index Results

There are 85 in-service SCADA Switches at GHESI. There were 85 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 78%. Approximately 4% of the units were found to be in poor condition.

The Health Index Results are as follows:

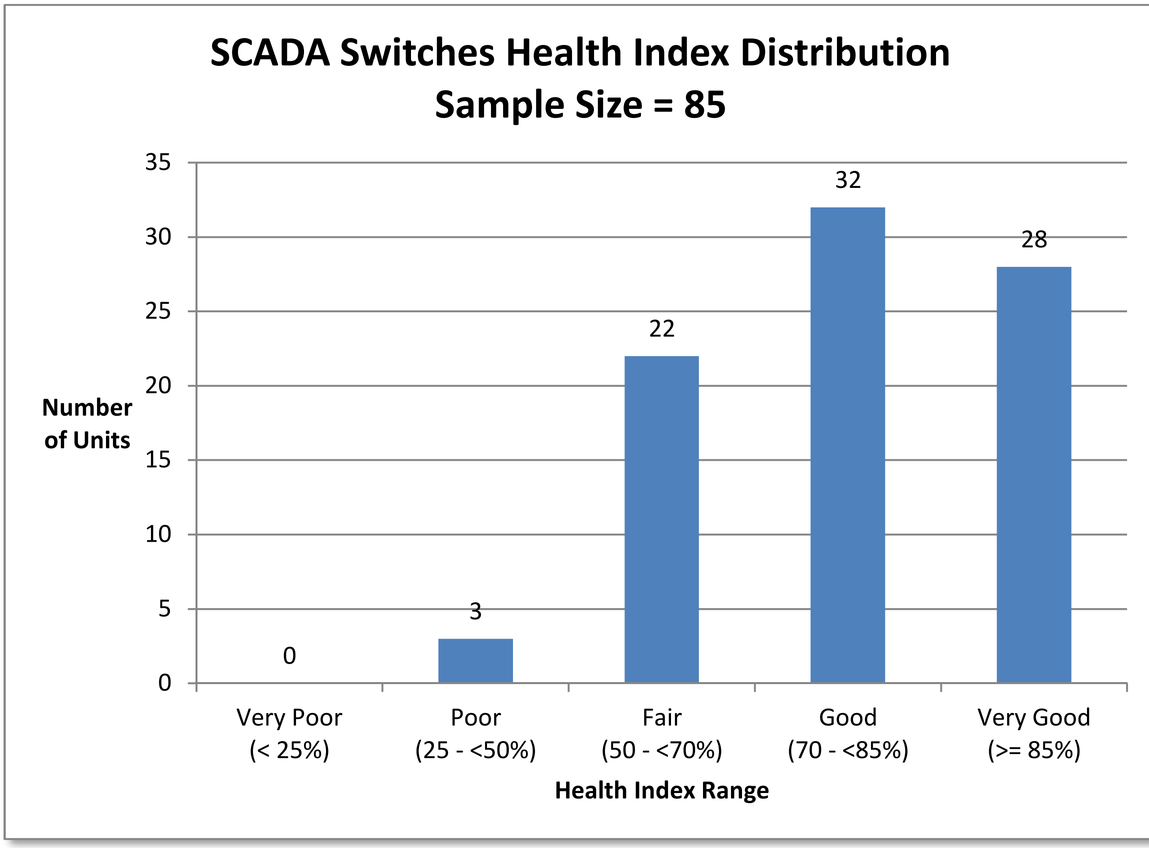


Figure 8-3 SCADA Switches Health Index Distribution (Number of Units)

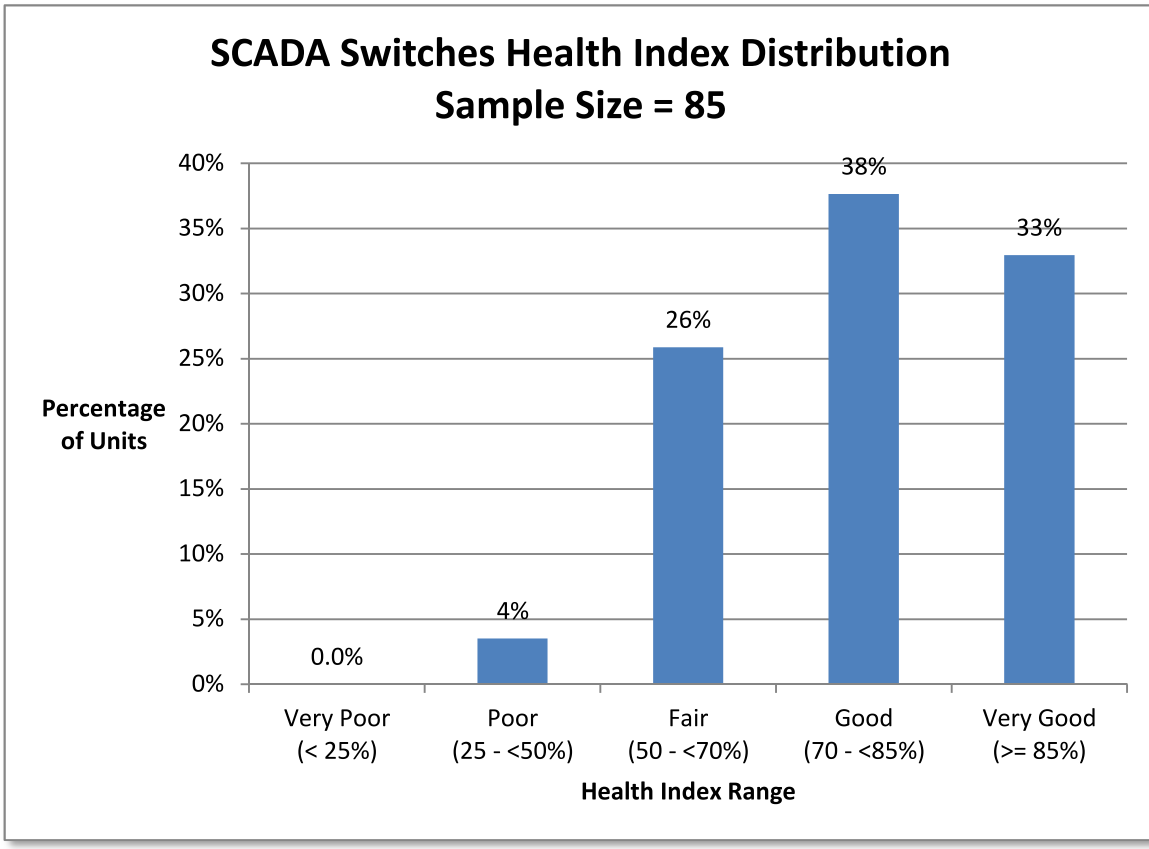


Figure 8-4 SCADA Switches Health Index Distribution (Percentage of Units)

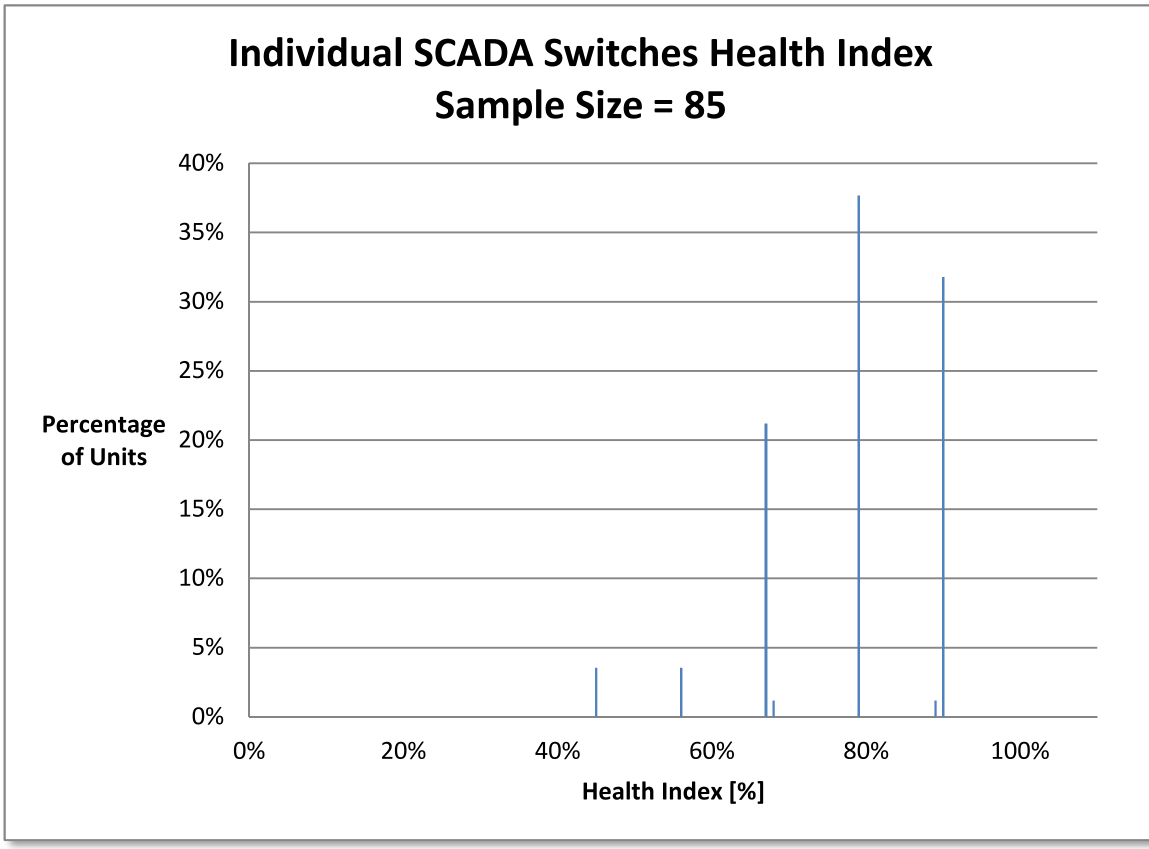


Figure 8-5 SCADA Switches Health Index Distribution by Value (Percentage of Units)

8.4 Condition-Based Flagged for Action Plan

As it is assumed that SCADA Switches are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

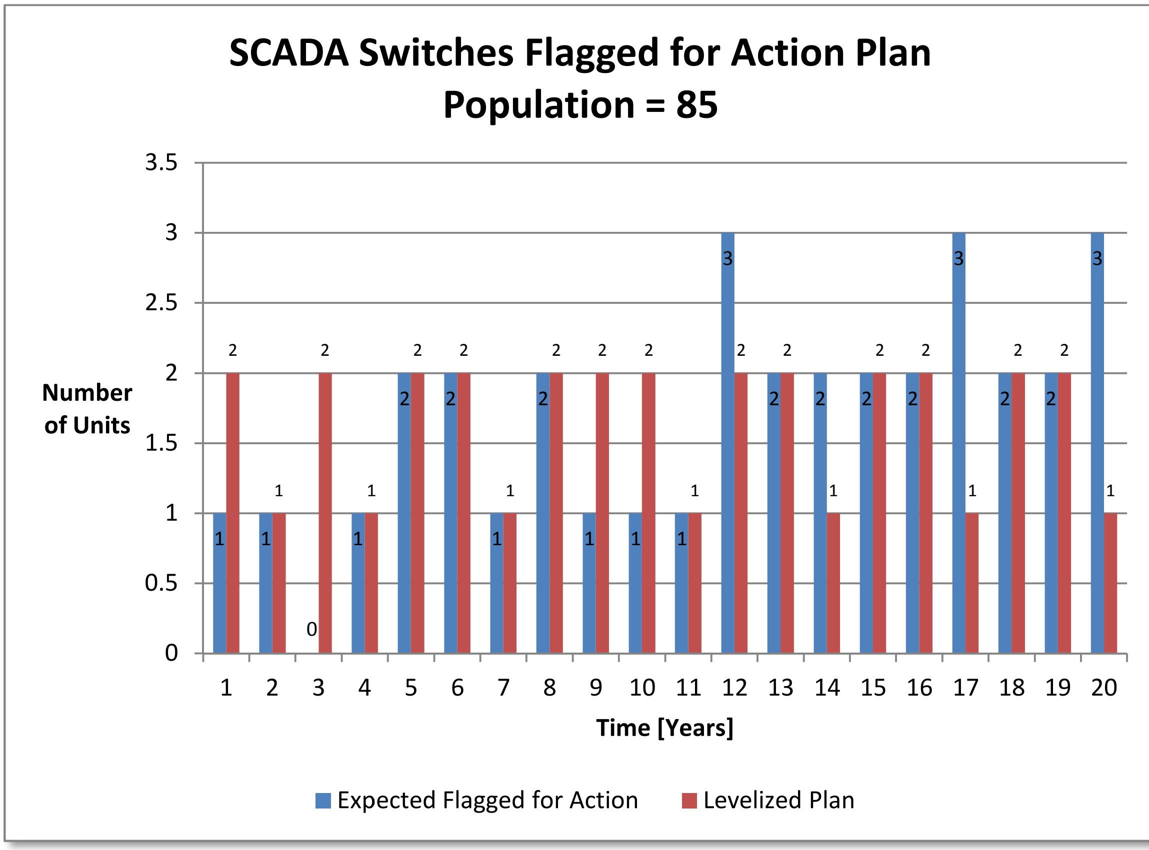


Figure 8-6 SCADA Switches Condition-Based Flagged for Action Plan

8.5 Data Analysis

8.5.1 Data Gap

The data available for SCADA Switches includes age, number of operations, and an indicator of whether the switch has been inspected or not. The data gaps, which are primarily from visual inspections, 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	**Switch**	☆☆☆	Blade	Blade condition	On-site visual inspection

8.5.2 Data Availability Distribution

Because there were no inspection records, the average DAI for SCADA Switches is 29%.

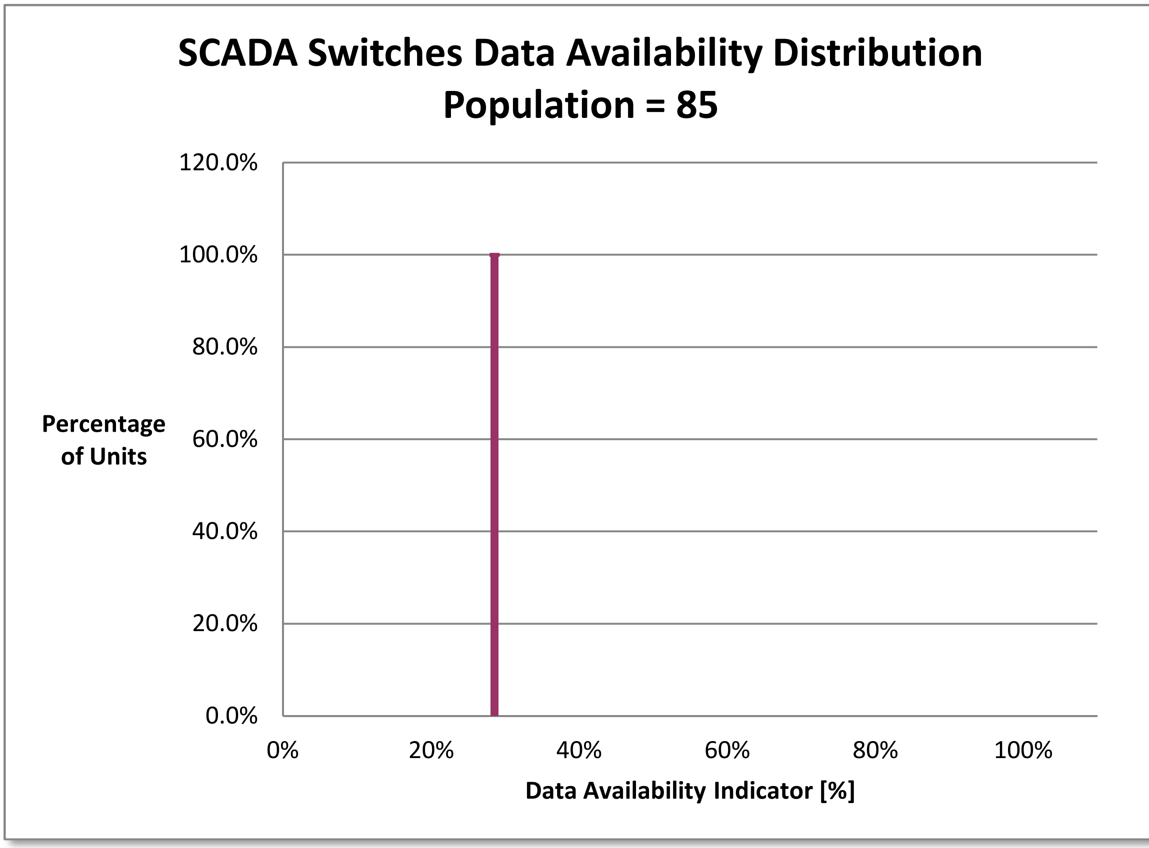


Figure 8-7 SCADA Switches Data Availability Distribution

9 Live Front Switchgear

9.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Live Front Switchgear. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Live Front Switchgear Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	3	Table 9-2
		Access	1	Table 9-2
		Base	2	Table 9-2
		Moisture	2	Table 9-2
Switch/Fuse Condition	1	Switch/Fuse Condition	1	
Insulation / Termination	1	Insulation	1	Table 9-2
		Termination	1	Table 9-2
Service Record	3	Overall Condition	4	Table 9-3
		Dry Ice	1	Table 9-4
		Safety Problem	1	Table 9-2
		Hot Spots	1	Table 9-2
		Age	3	Figure 9-1

9.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Live Front 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 30 and 40 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

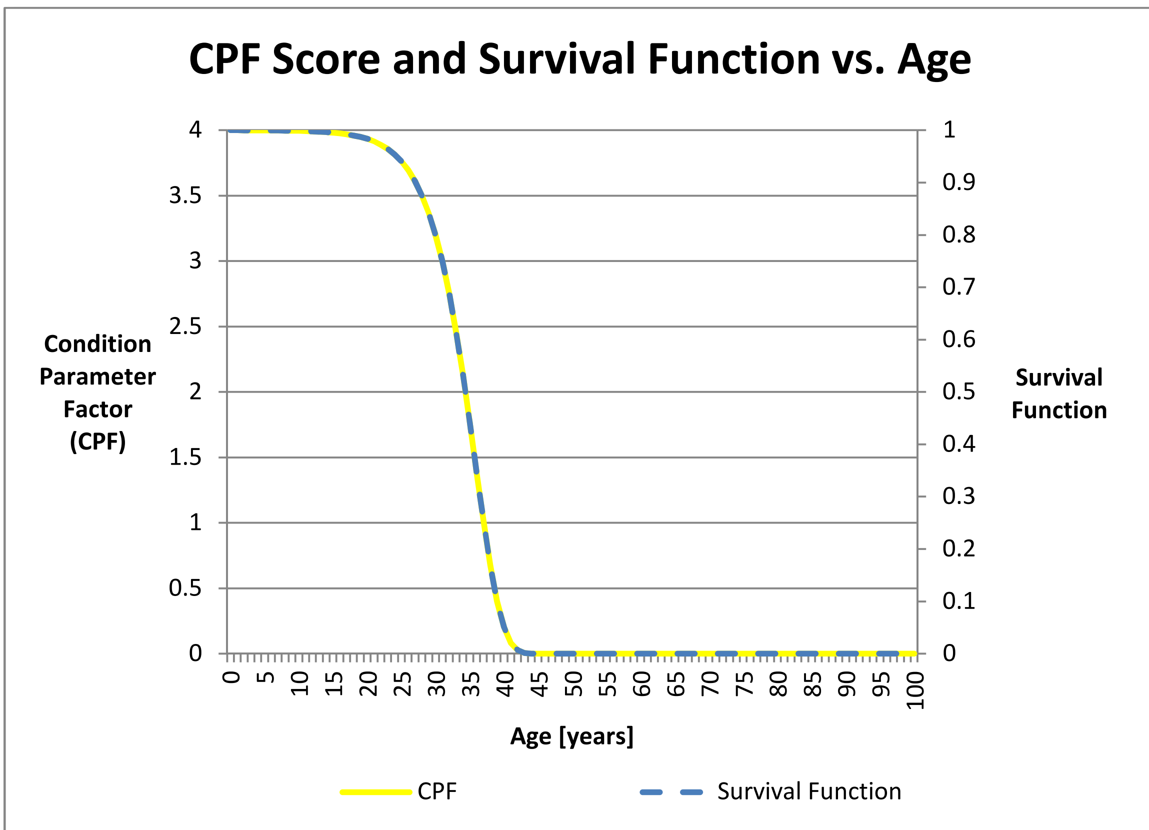


Figure 9-1 Live Front Switchgear Age Condition Criteria

Okay or Not Okay

Table 9-2 Live Front Switchgear Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Status

Table 9-3 Live Front Switchgear Status Description and Score

Status	Score
PROBLEM	0
NO PROBLEM	4
FIXED	3

Dry Ice

Table 9-4 Live Front Switchgear Dry Ice Description and Score

Dry Ice Complete	Score
Complete	4
Not Complete	0

9.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 12 years.

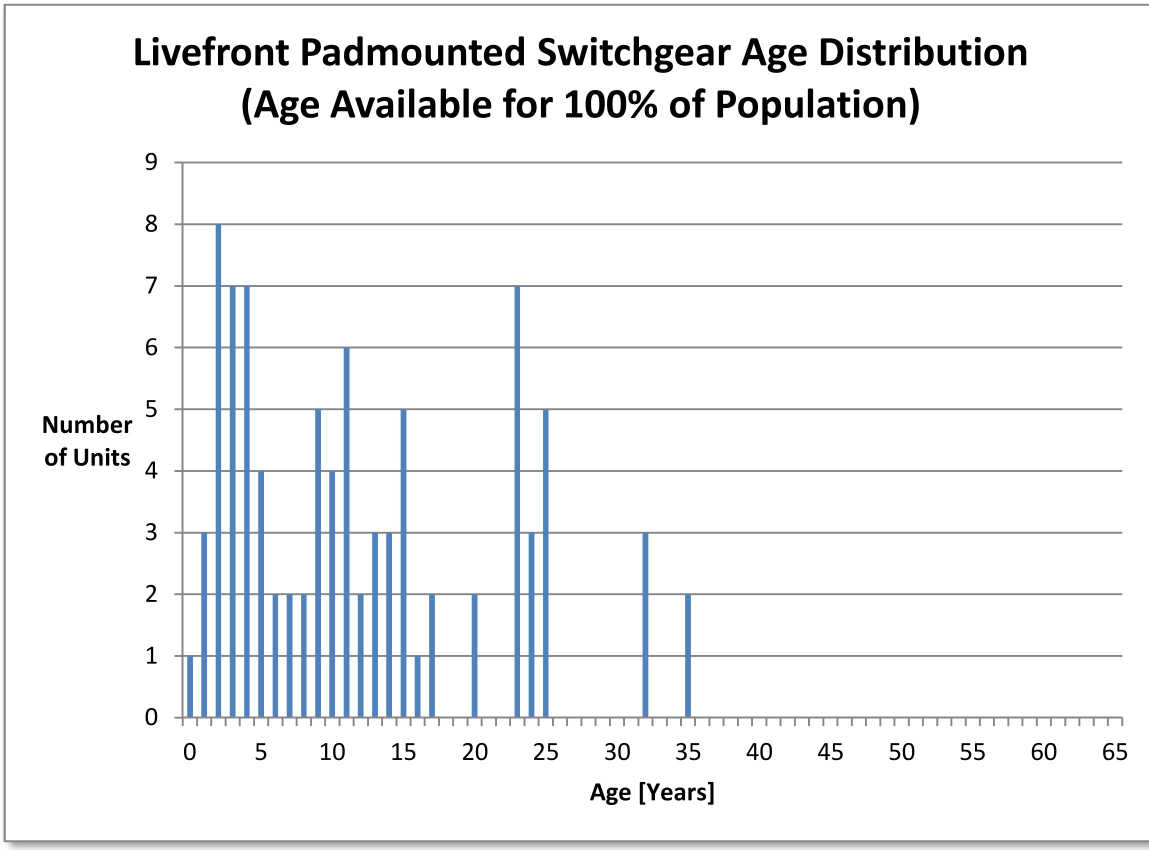


Figure 9-2 Live Front Switchgear Age Distribution

9.3 Health Index Results

There are 89 in-service Live Front Switchgear at GHESI. There were 89 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 90%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

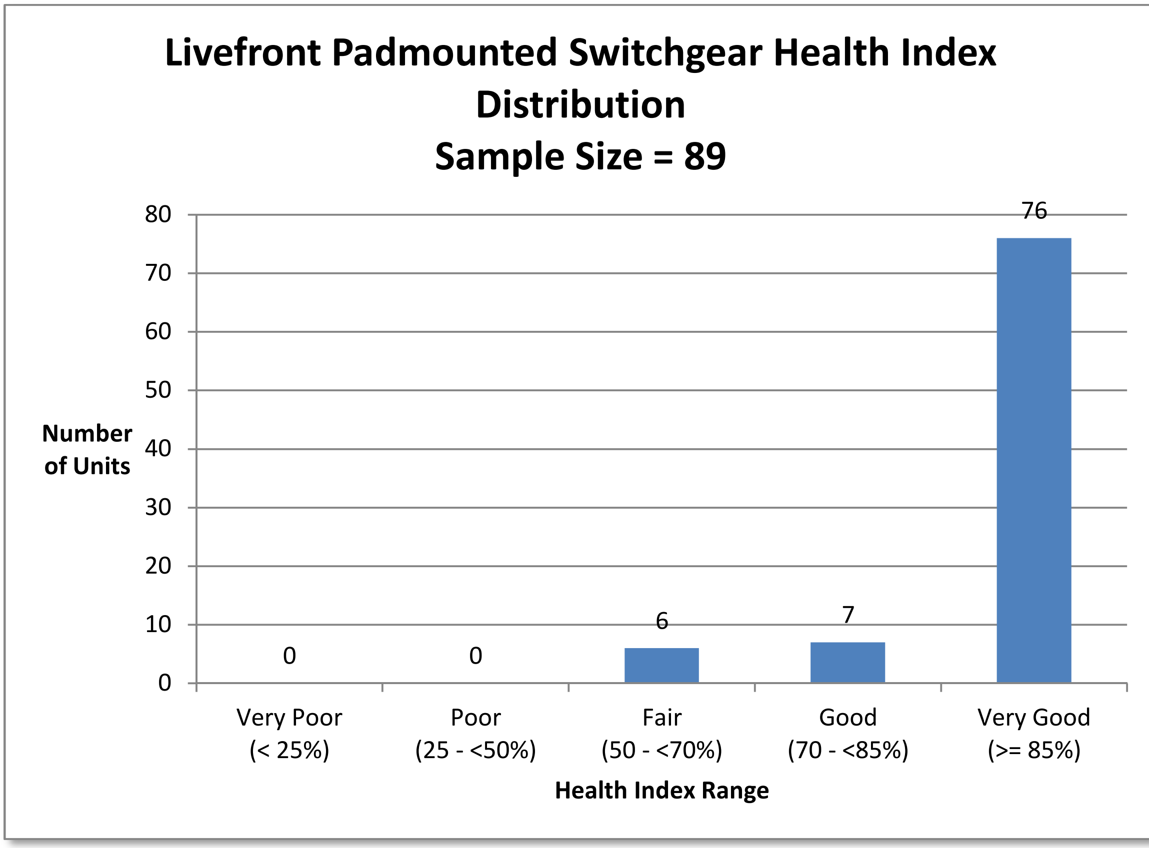


Figure 9-3 Live Front Switchgear Health Index Distribution (Number of Units)

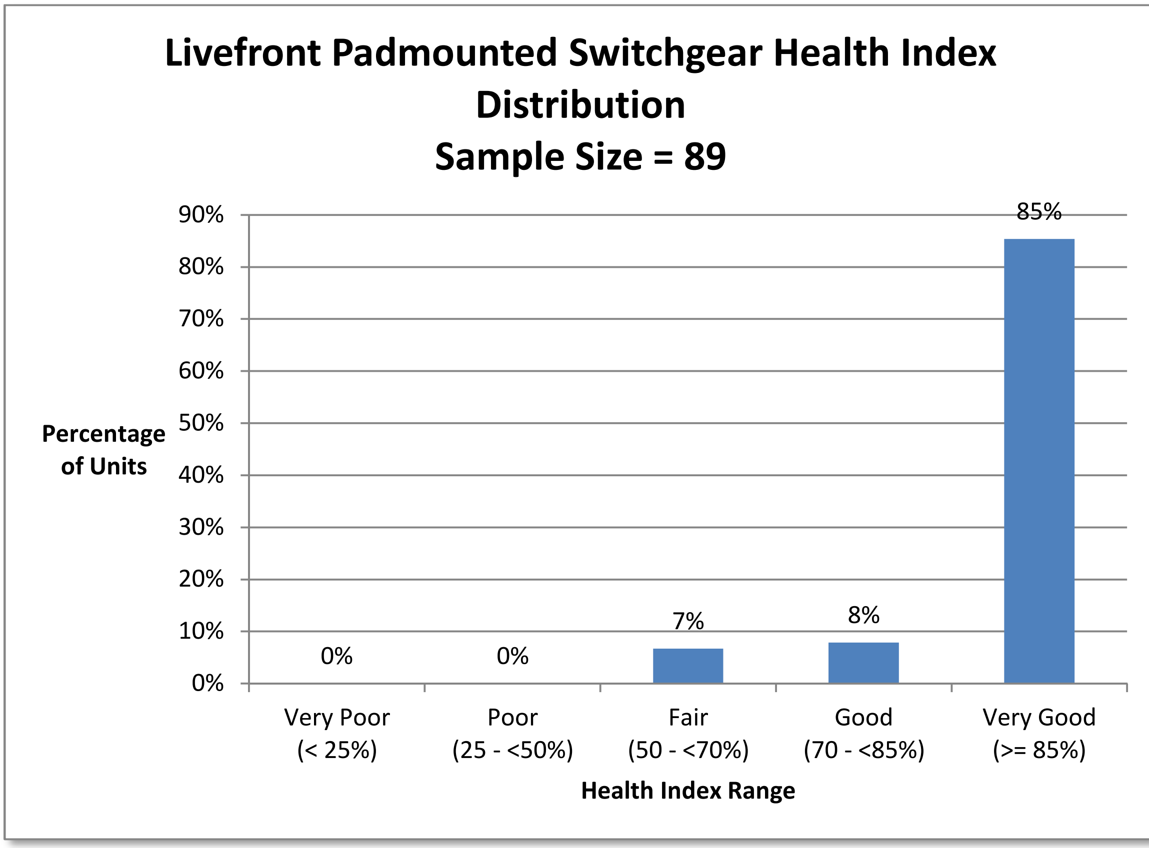


Figure 9-4 Live Front Switchgear Health Index Distribution (Percentage of Units)

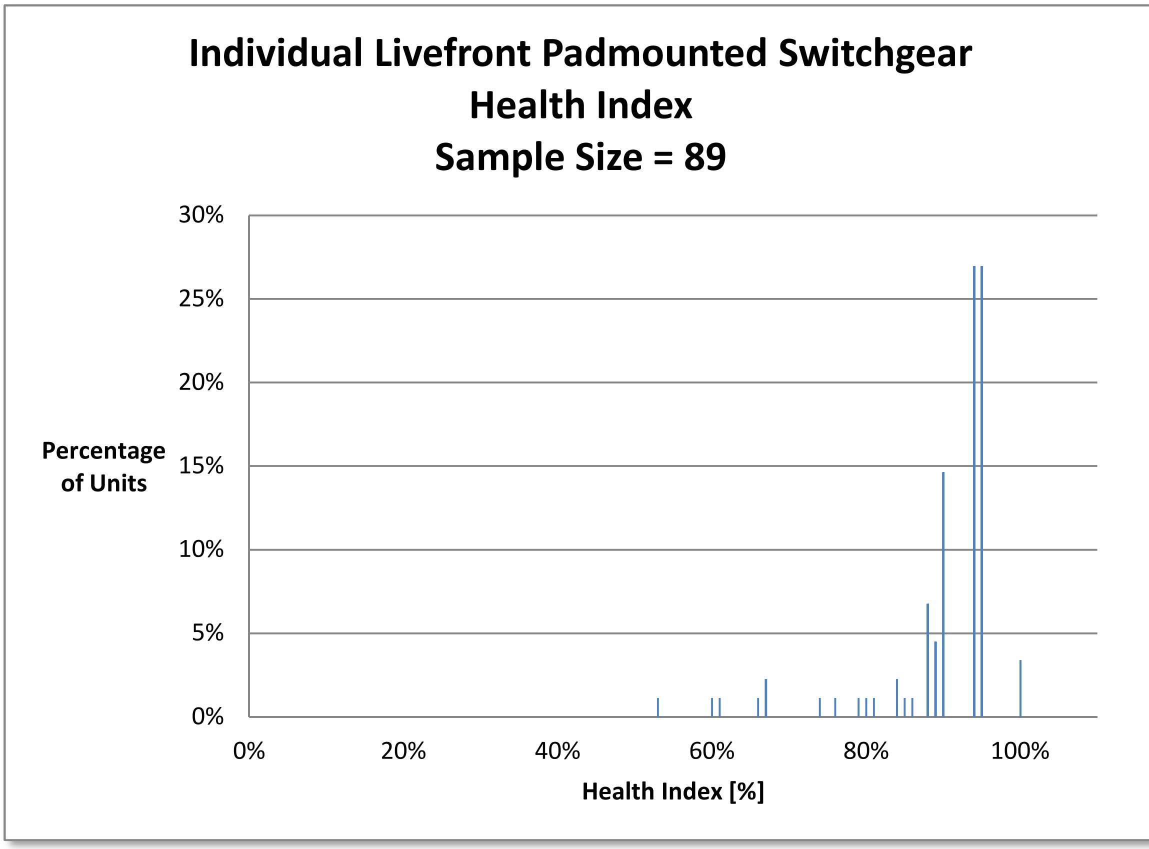


Figure 9-5 Live Front Switchgear Health Index Distribution by Value (Percentage of Units)

9.4 Condition-Based Flagged for Action Plan

As it is assumed that Live Front Switchgear are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a “levelized” plan, based on accelerating or replacing prior to expected time of action, is also given.

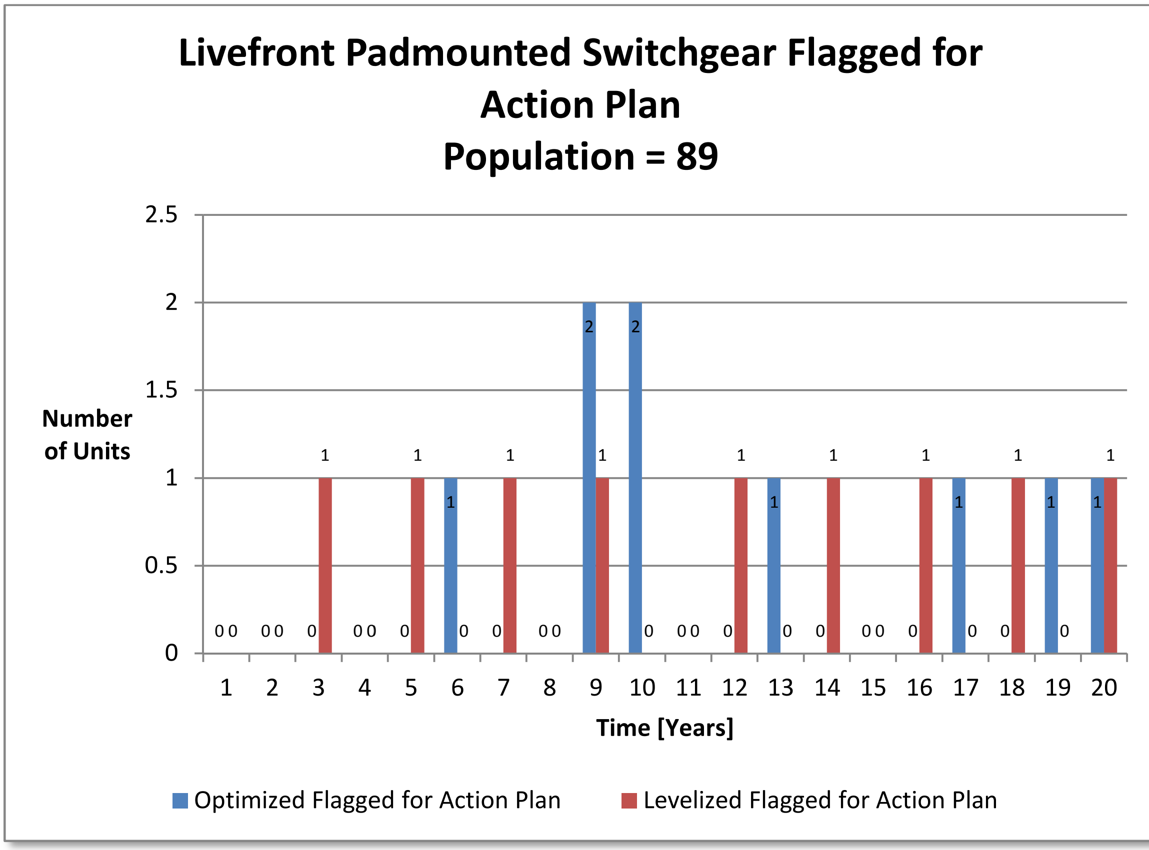


Figure 9-6 Live Front Switchgear Condition-Based Flagged for Action Plan

9.5 Data Analysis

The data available for Live Front Switchgear are age and inspection records. Data gaps identified for this asset class are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Switch	Switch/Fuse Condition	☆☆	Switch	Misalignment, signs of arcing	Visual inspection
Arc Suppressor		☆☆	Switch arc extinction	Arc extinction part surface worn-out	Visual inspection
Fuse		☆☆	Fuse	Fuse visual condition	Visual inspection
Elbows/Inserts		☆☆	Connection	Poor connection / hot spots	Visual inspection or IR scan

9.5.1 Data Availability Distribution

The data availability was generally good; the average DAI for Live Front Switchgear is 79%.

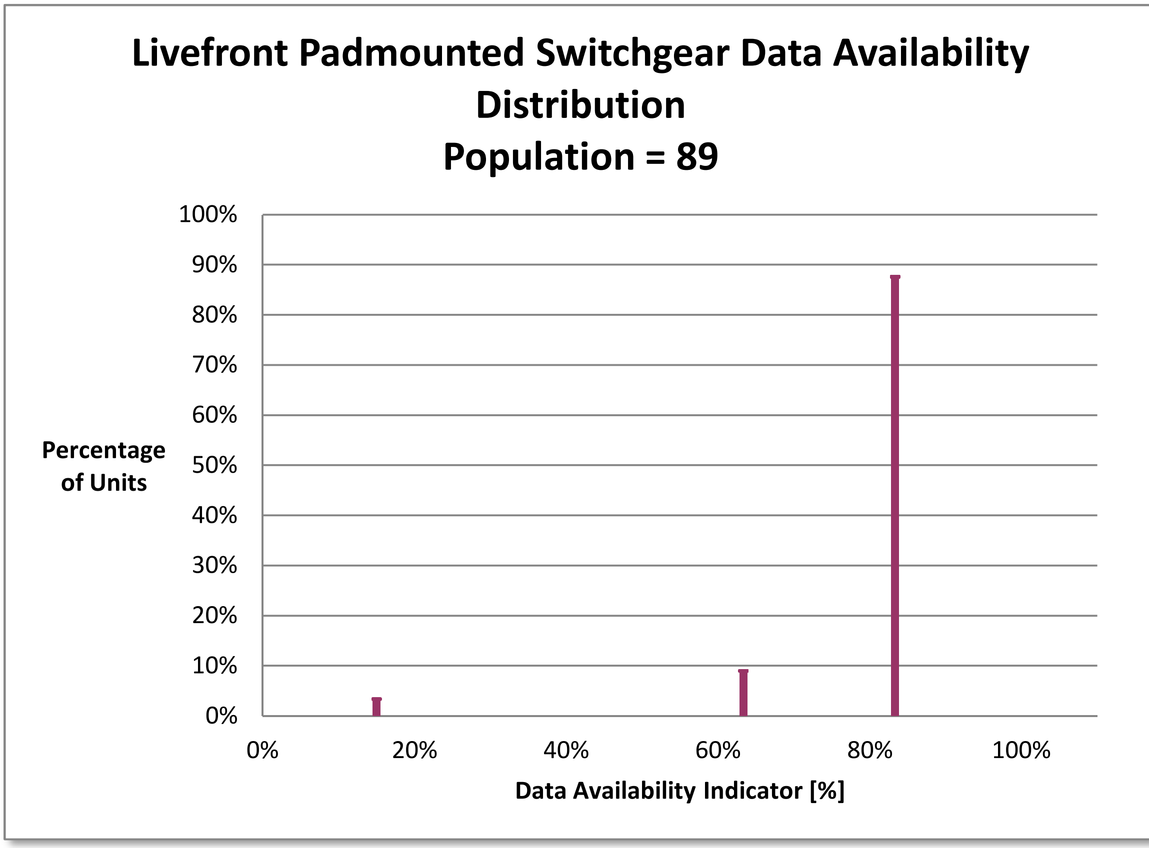


Figure 9-7 Live Front Switchgear Data Availability Distribution

10 Solid Dielectric Switchgear

10.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Solid Dielectric Switchgear. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

10.1.1 Condition and Sub-Condition Parameters

Table 10-1 Solid Dielectric Switchgear Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	3	
		Access	1	
		Base	2	
		Moisture	2	
Insulation / Termination	1	Insulation	1	
		Termination	1	
Service Record	3	Overall Condition	4	
		Safety Problem	1	
		Hot Spots	1	
		Age	3	Figure 10-1

10.1.2 Condition Parameter Criteria

__Age__

Assume that the failure rate for Solid Dielectric 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 30 and 50 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

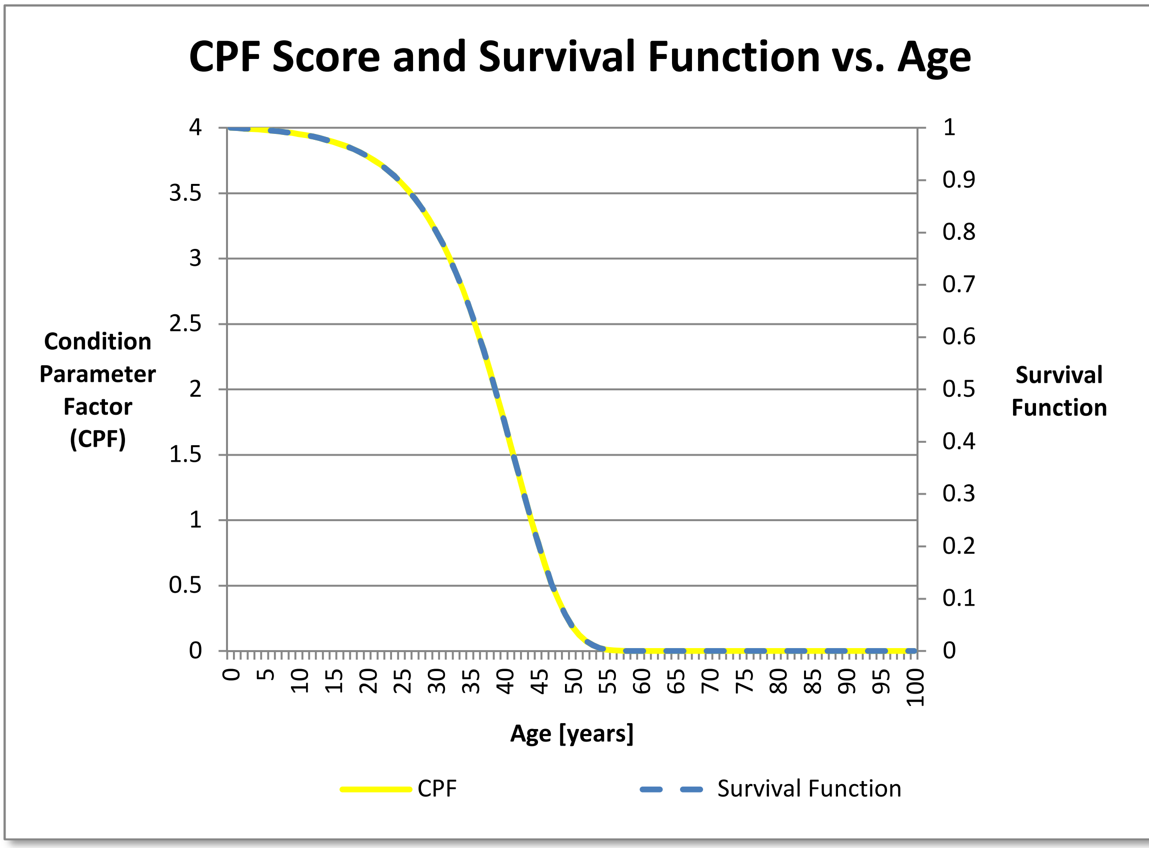


Figure 10-1 Solid Dielectric Switchgear Age Condition Criteria

10.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 1 years.

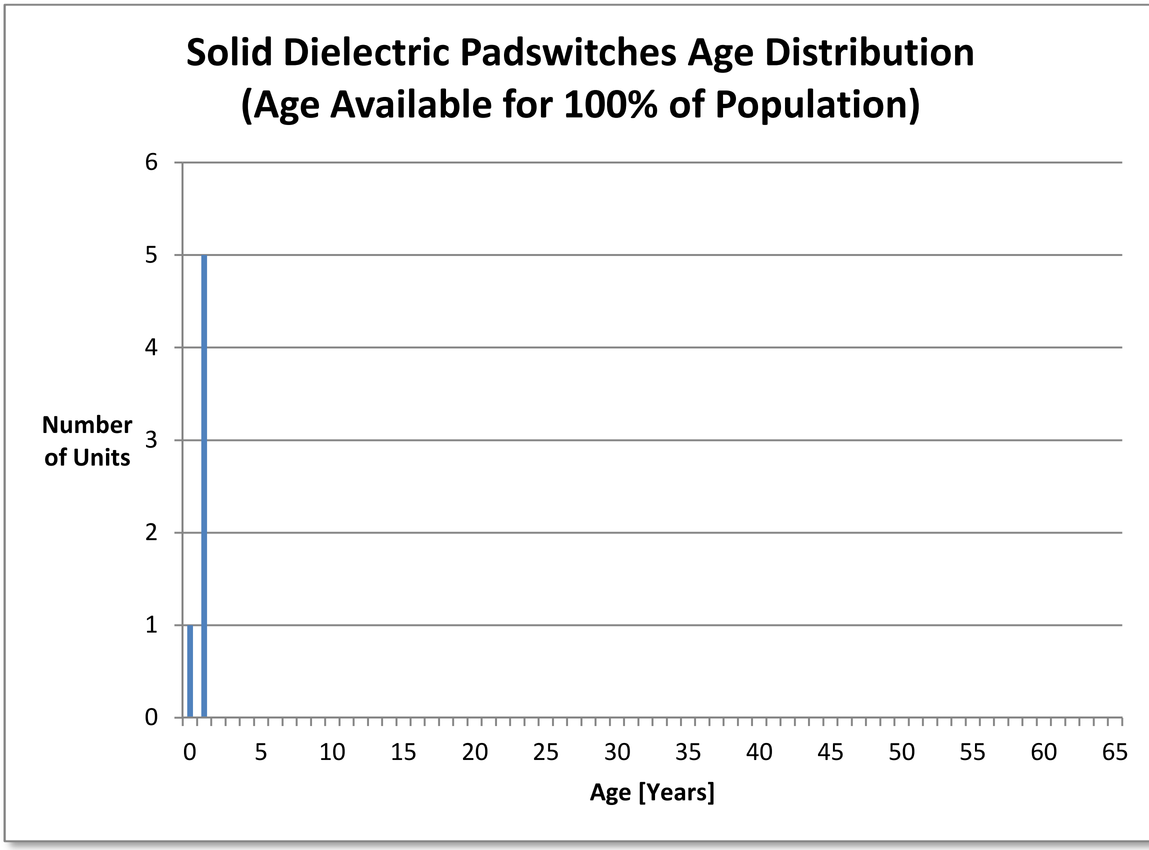


Figure 10-2 Solid Dielectric Switchgear Age Distribution

10.3 Health Index Results

There are 6 in-service Solid Dielectric Switchgear at GHESI. There were 6 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 100%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

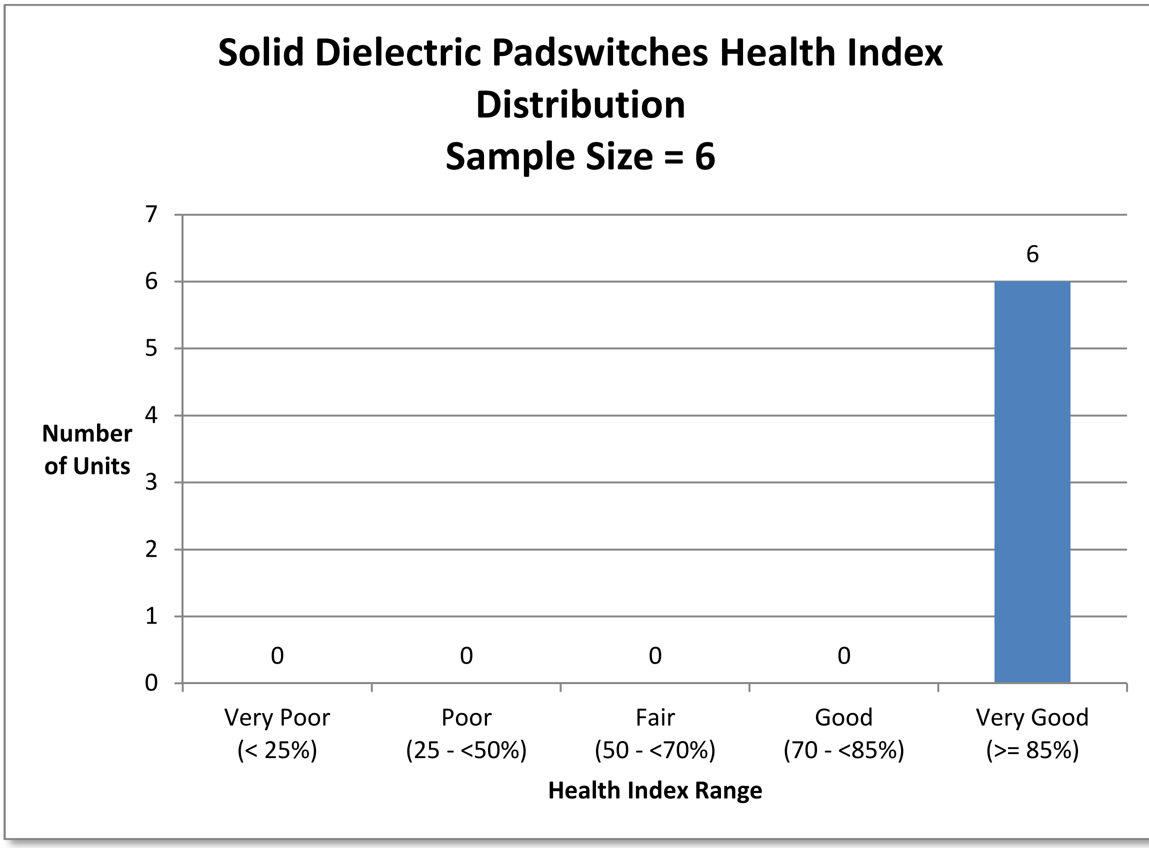


Figure 10-3 Solid Dielectric Switchgear Health Index Distribution (Number of Units)

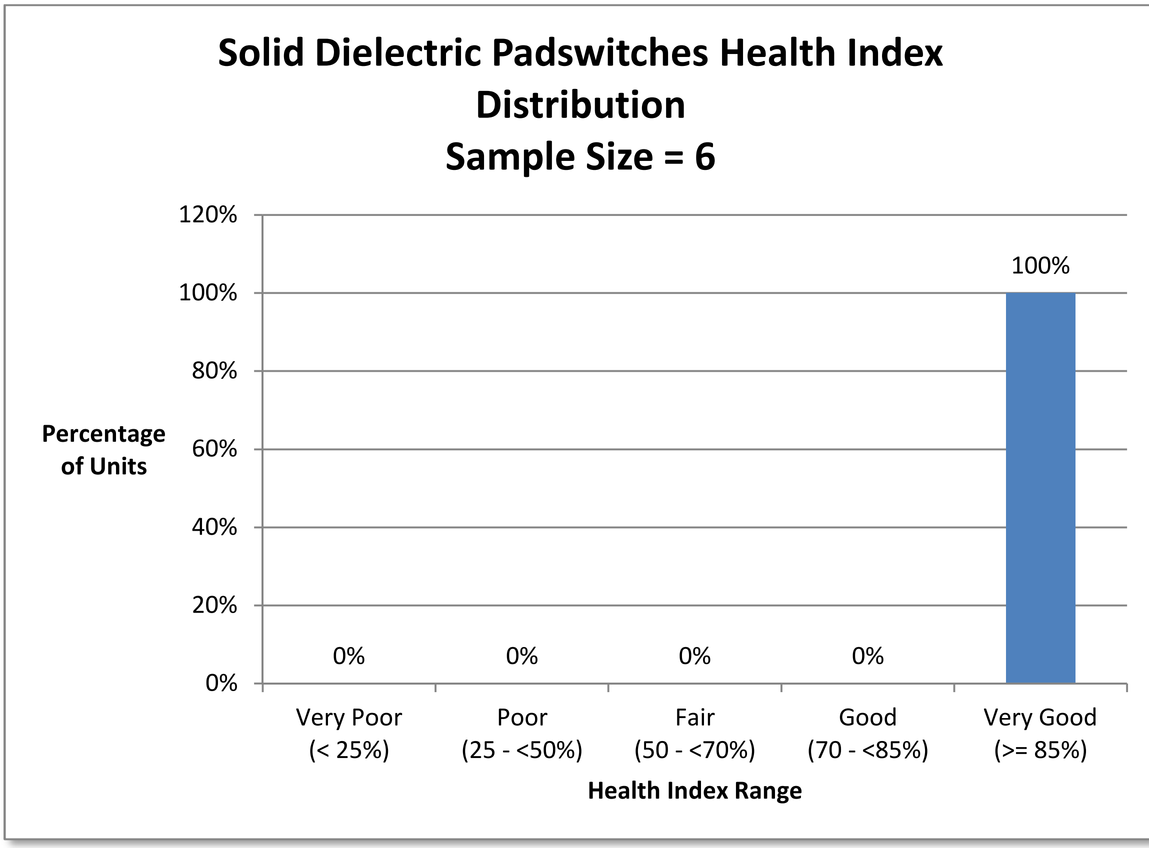


Figure 10-4 Solid Dielectric Switchgear Health Index Distribution (Percentage of Units)

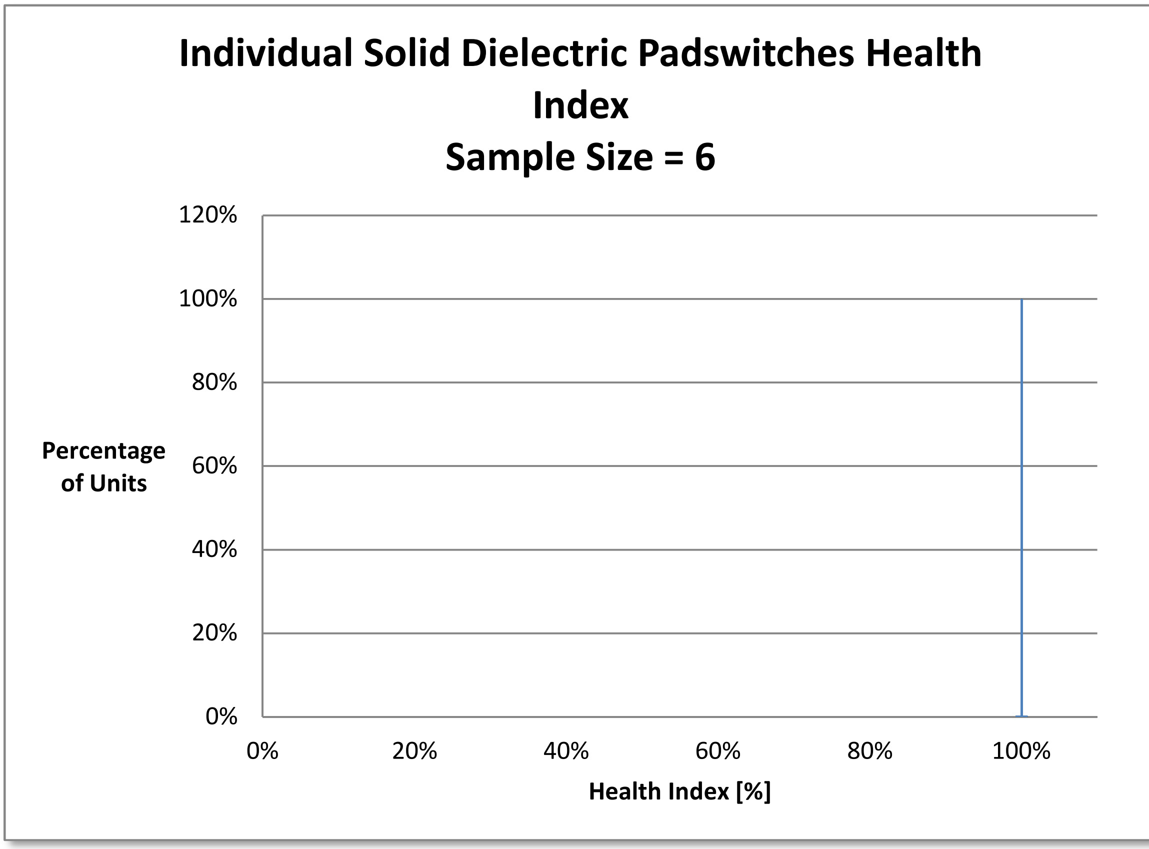


Figure 10-5 Solid Dielectric Switchgear Health Index Distribution by Value (Percentage of Units)

10.4 Condition-Based Flagged for Action Plan

As it is assumed that Solid Dielectric Switchgear are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

No units are flagged for action in the next 20 years.

10.5 Data Analysis

10.5.1 Data Gap

Only age was available for Solid Dielectric Switchgear. There are no data gaps for this asset category.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Corrosion	Physical Condition	☆☆	Switchgear enclosure	Tank surface rust or deterioration due to environmental factors	Visual inspection
Access		☆	Switchgear case	Corrosion / Obstruction to work	Visual inspection
Base		☆	Foundation	Cracks or alignment issues	Visual inspection
Termination / Connection	Termination / Connection	☆☆	Connections and terminations	Loose connections	Visual inspection
Overall	Service Record	☆☆☆	Switchgear	General status evaluation based on routine operation and inspection	Visual Inspection

10.5.2 Data Availability Distribution

The average DAI for Solid Dielectric Switchgear is 20%.

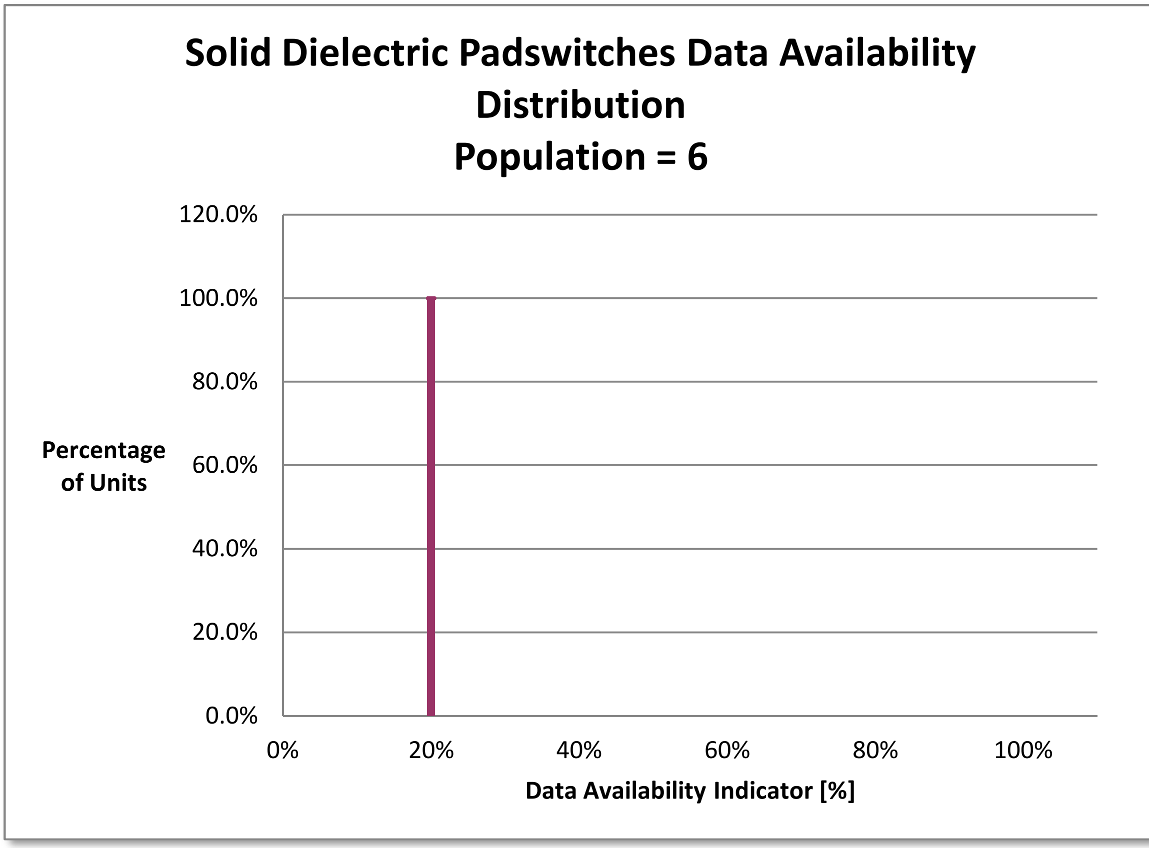


Figure 10-6 Solid Dielectric Switchgear Data Availability Distribution

11 Kabars

11.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Kabars. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

11.1.1 Condition and Sub-Condition Parameters

Table 11-1 Kabars Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Corrosion	3	
		Access	1	
		Base	2	
Connection/Terminations	1	Connection/Terminations	1	
Service Record	3	Overall Condition	1	Table 9-3
		Age	1	Figure 11-1

11.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Kabars 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 30 and 50 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

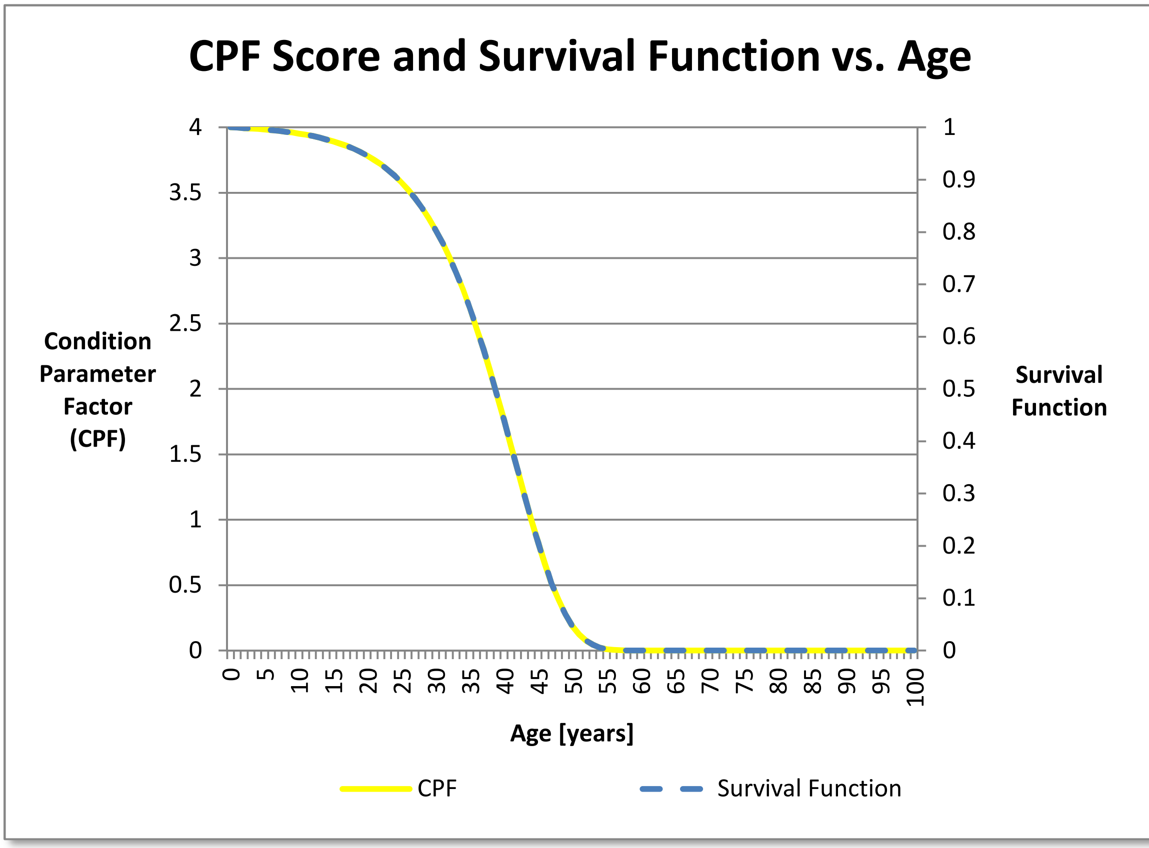


Figure 11-1 Kabars Age Condition Criteria

11.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 14 years.

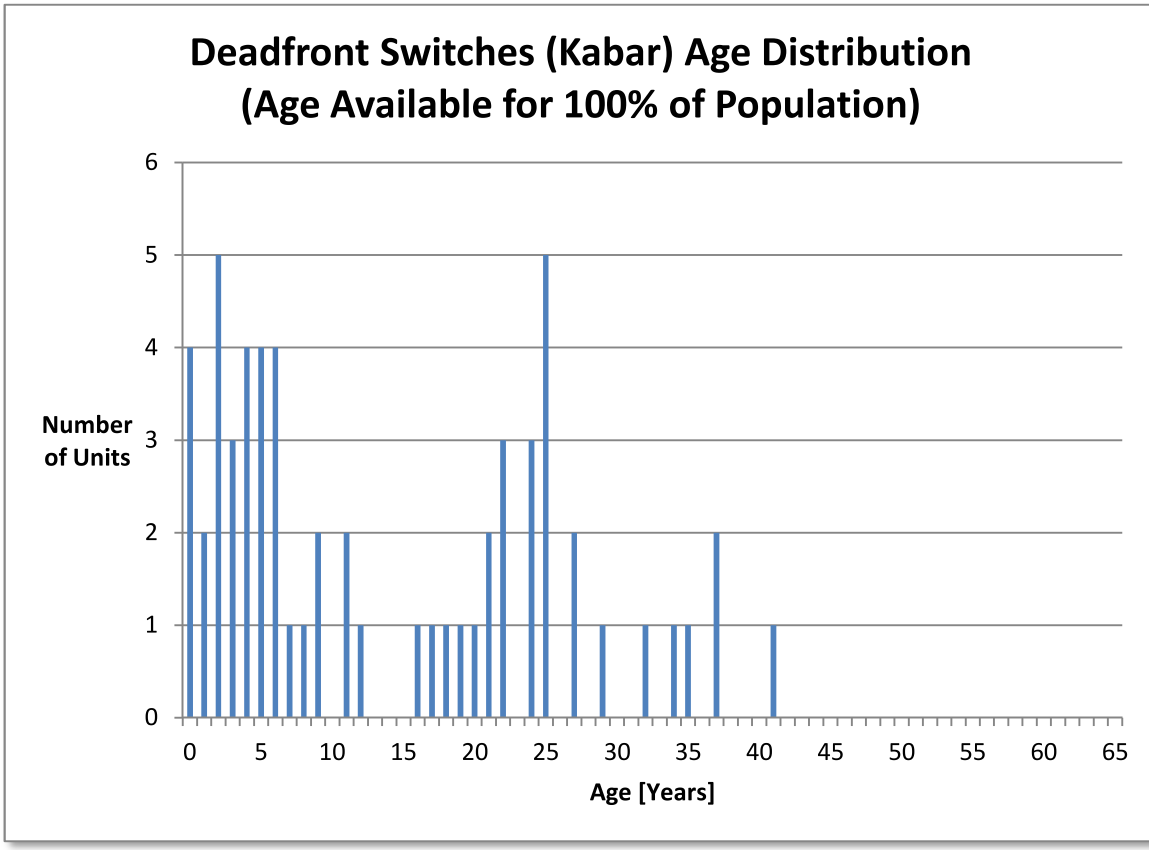


Figure 11-2 Kabars Age Distribution

11.3 Health Index Results

There are 60 in-service Kabars at GHESI. There were 60 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 93%. Approximately 2% of the units were found to be in poor condition.

The Health Index Results are as follows:

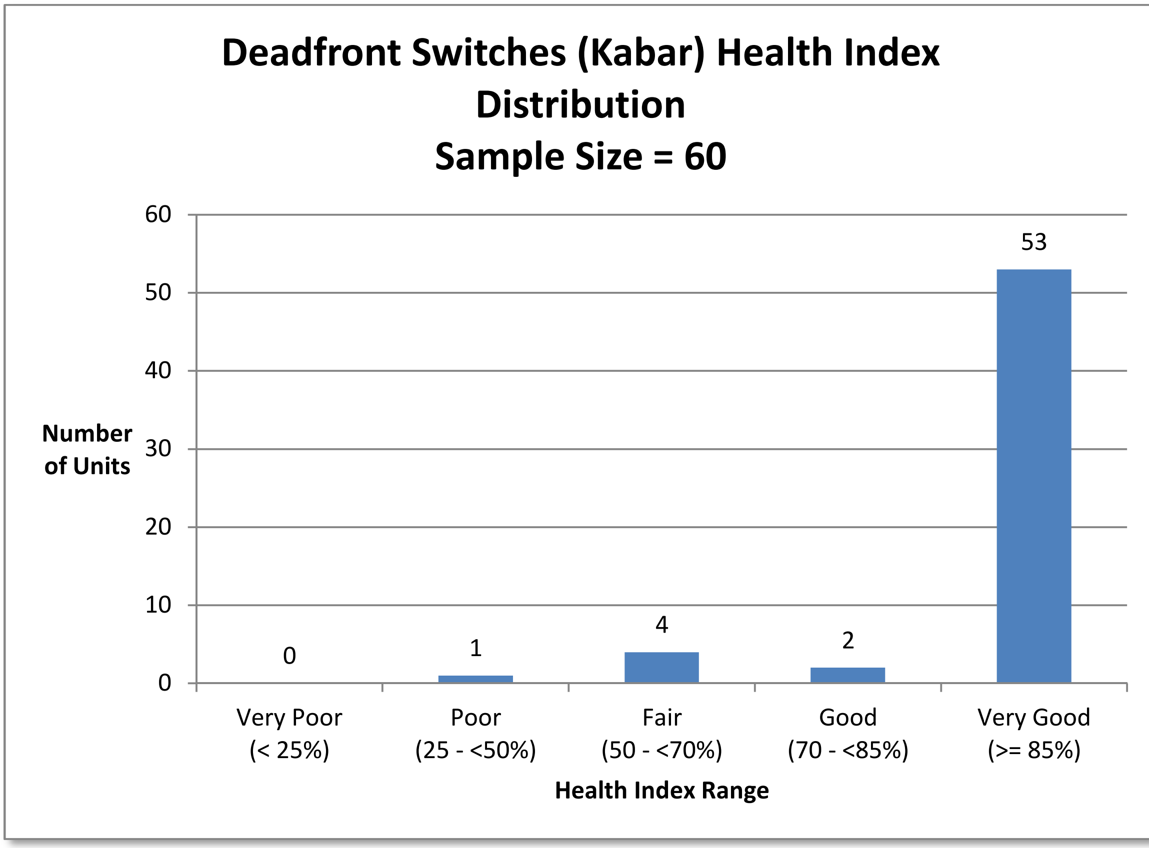


Figure 11-3 Kabars Health Index Distribution (Number of Units)

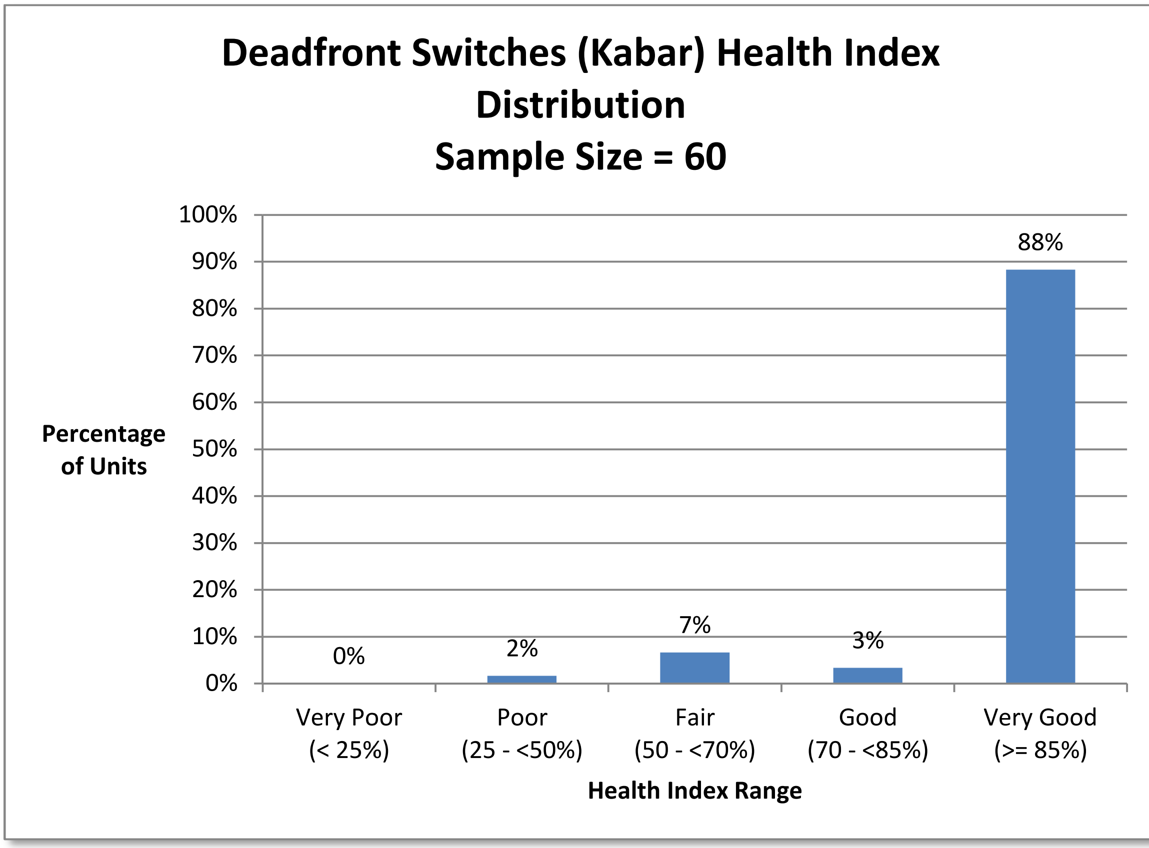


Figure 11-4 Kabars Health Index Distribution (Percentage of Units)

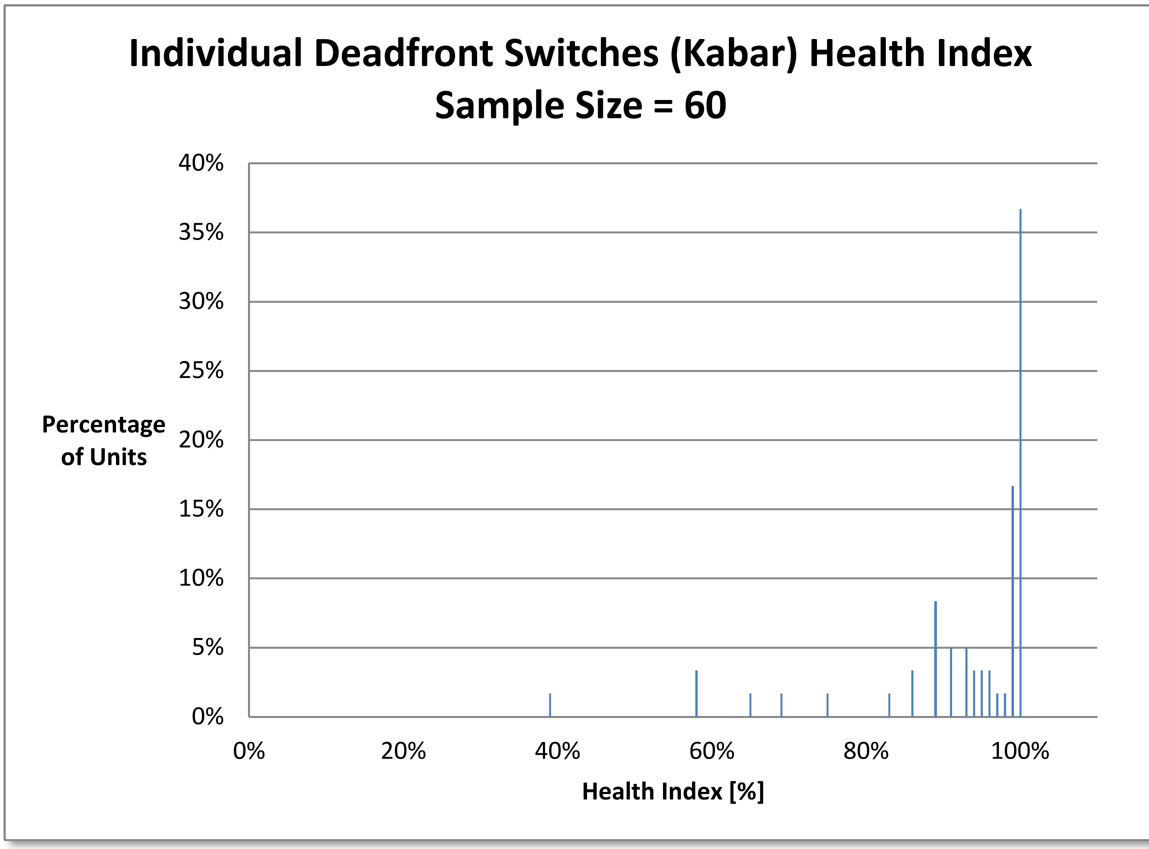


Figure 11-5 Kabars Health Index Distribution by Value (Percentage of Units)

11.4 Condition-Based Flagged for Action Plan

As it is assumed that Kabars are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

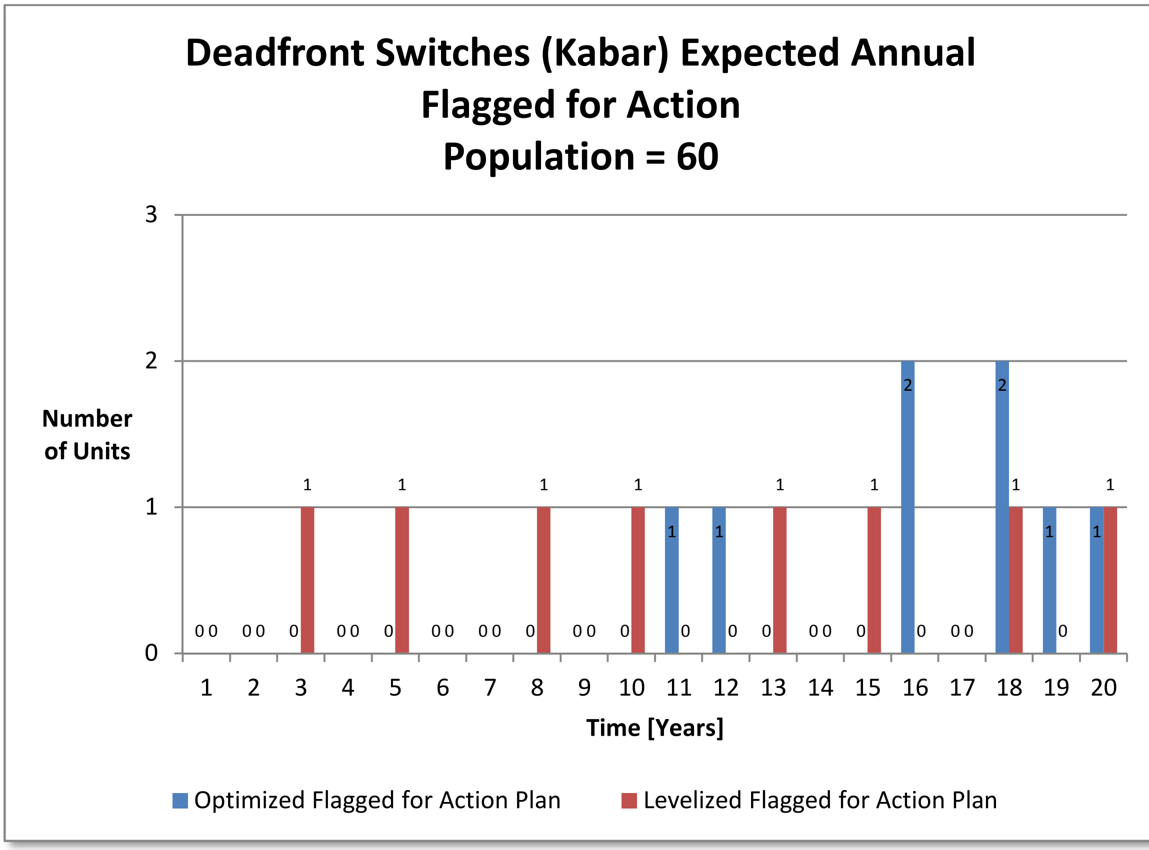


Figure 11-6 Kabars Condition-Based Flagged for Action Plan

11.5 Data Analysis

11.5.1 Data Gap

The only data available for Kabars was age only. Data gaps identified are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Corrosion	Physical Condition	☆☆	Enclosure	Surface rust or deterioration due to environmental factors	Visual inspection
Access		☆	Case	Obstruction to work	Visual inspection
Base		☆	Foundation	Cracks or alignment issues	Visual inspection
Termination / Connection	Termination/ Connection	☆☆	Connections and terminations	Loose connections	Visual inspection
Overall	Service Record	☆☆☆	Kabar Unit	General status evaluation based on routine operation and inspection	Visual Inspection

11.5.2 Data Availability Distribution

Because only age is known for this asset category, the average DAI for Kabars is 17%.

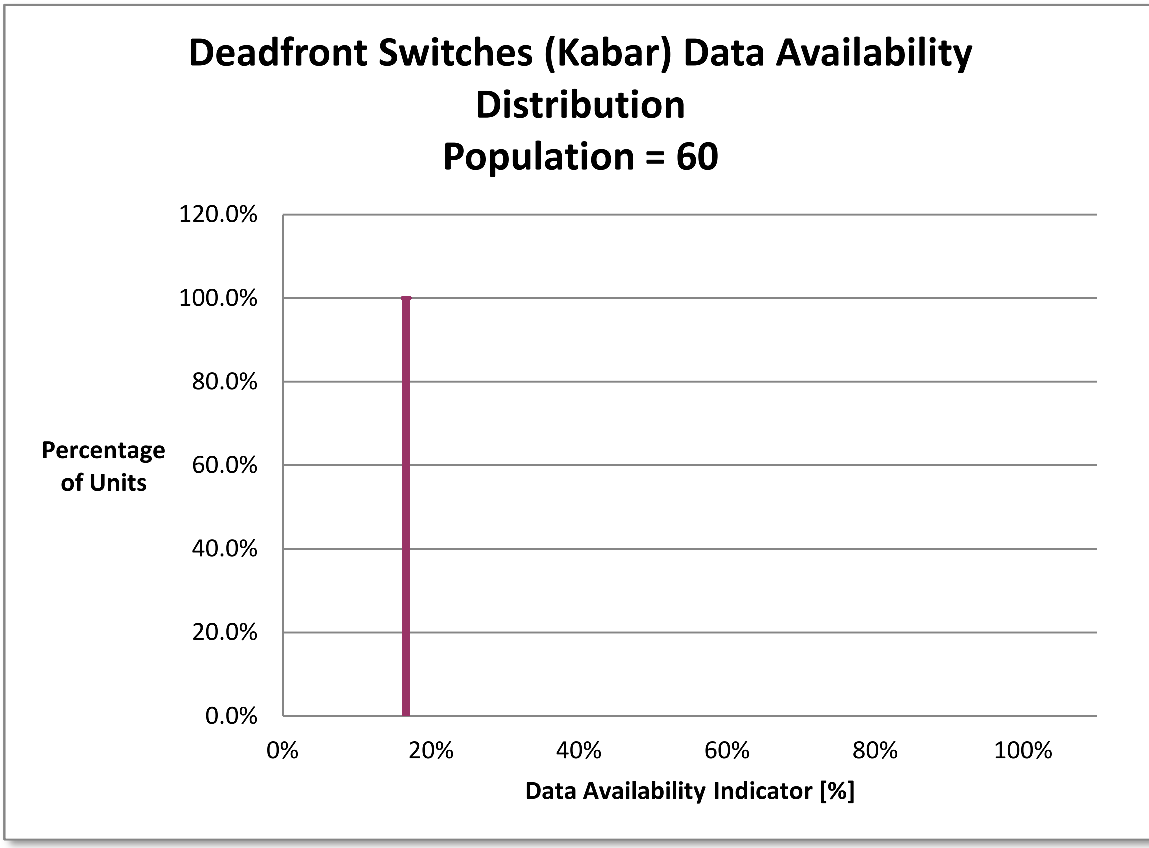


Figure 11-7 Kabars Data Availability Distribution

12 Multijunctions

12.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Multijunctions. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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”.

12.1.1 Condition and Sub-Condition Parameters

Table 12-1 Multijunctions Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Connection	1	Connection	1	
Service Record	3	Overall Condition	1	Table 9-3
		Age	1	Figure 12-1

12.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Multijunctions 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 30 and 50 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

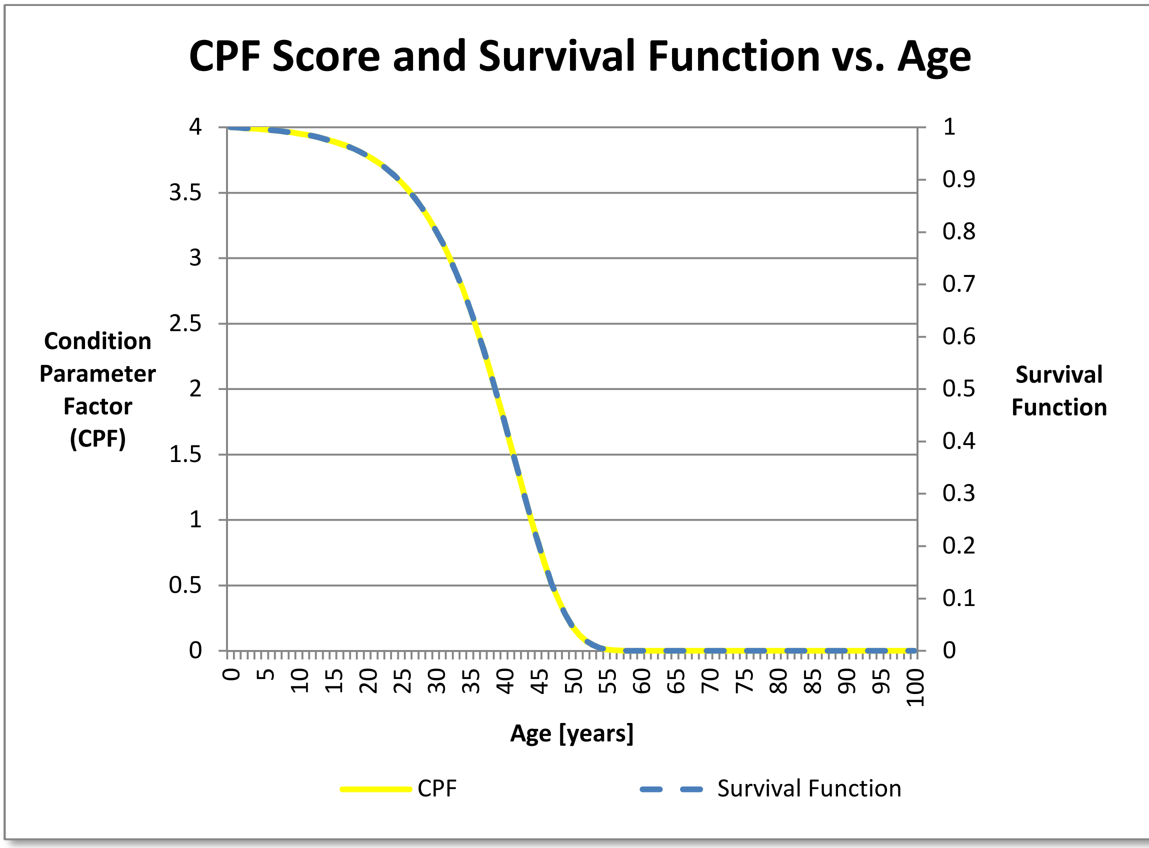


Figure 12-1 Multijunctions Age Condition Criteria

12.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 23 years.

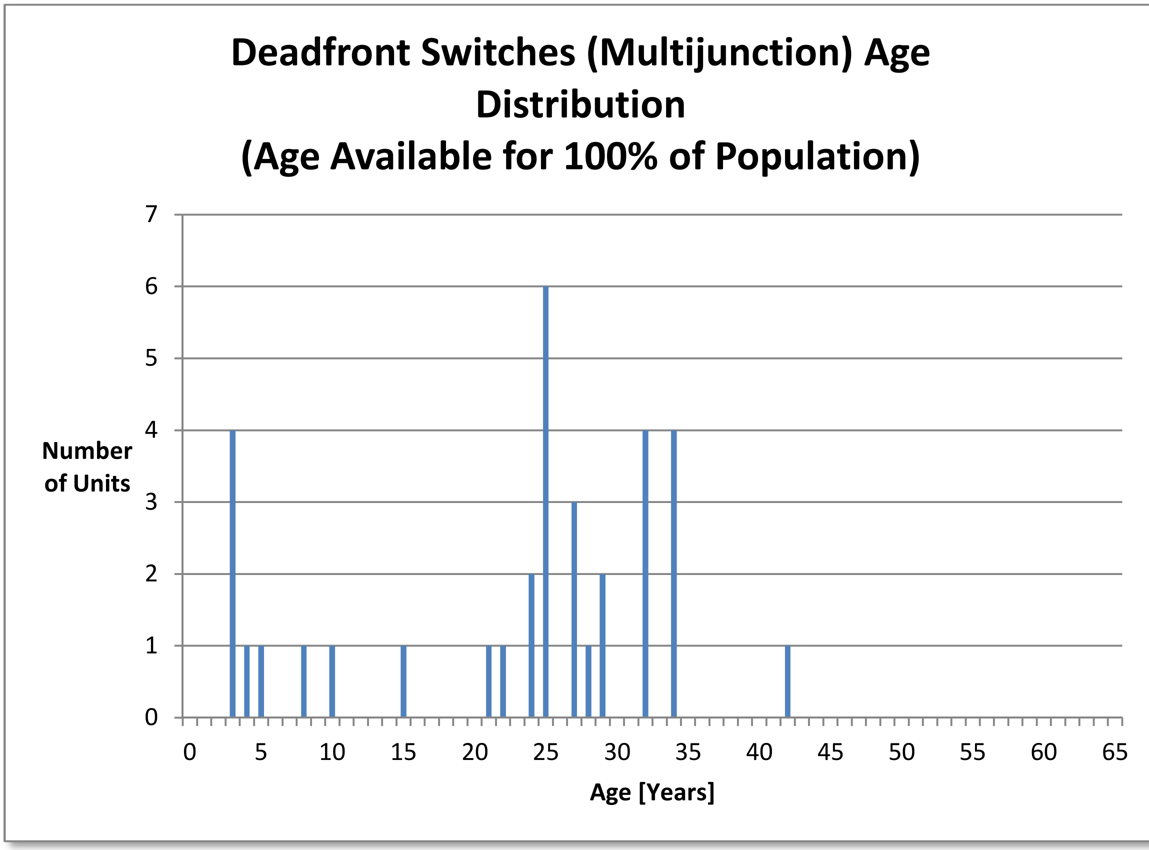


Figure 12-2 Multijunctions Age Distribution

12.3 Health Index Results

There are 34 in-service Multijunctions at GHESI. There were 34 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 86%. Approximately 3% of the units were found to be in poor condition.

The Health Index Results are as follows:

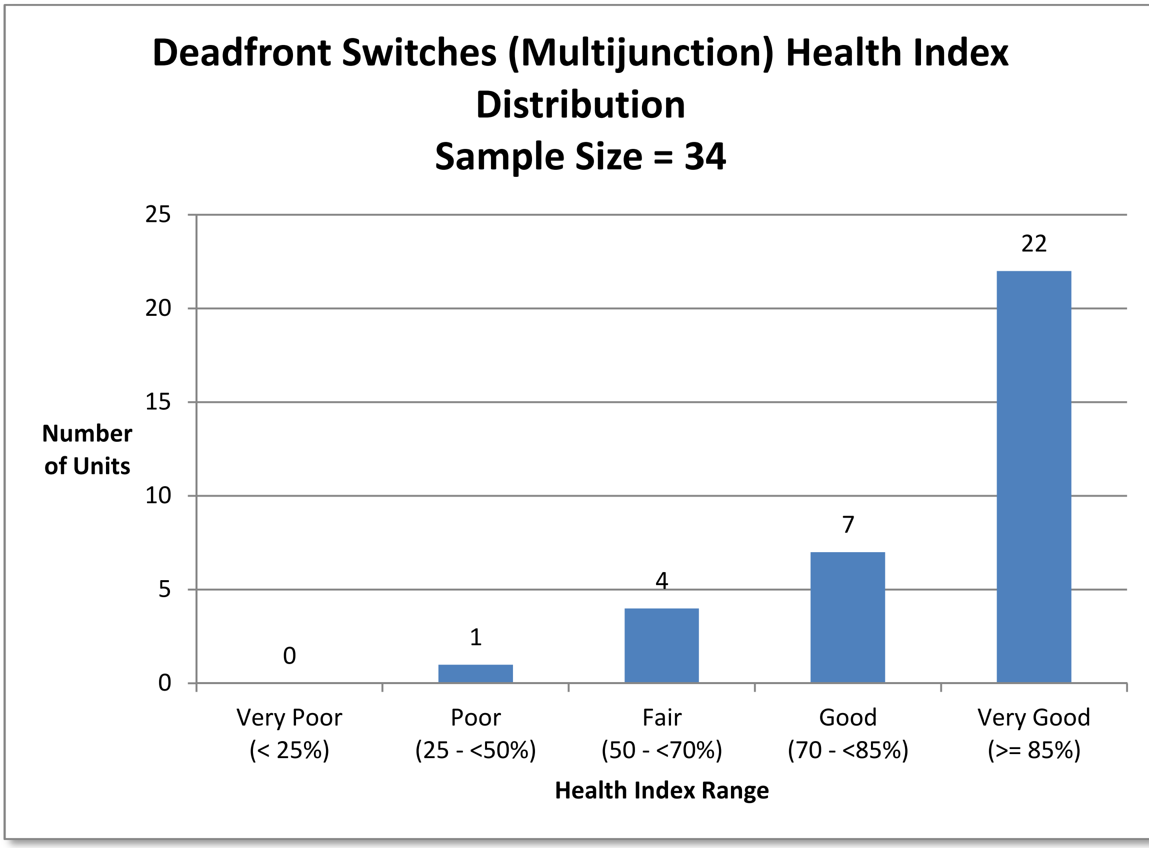


Figure 12-3 Multijunctions Health Index Distribution (Number of Units)

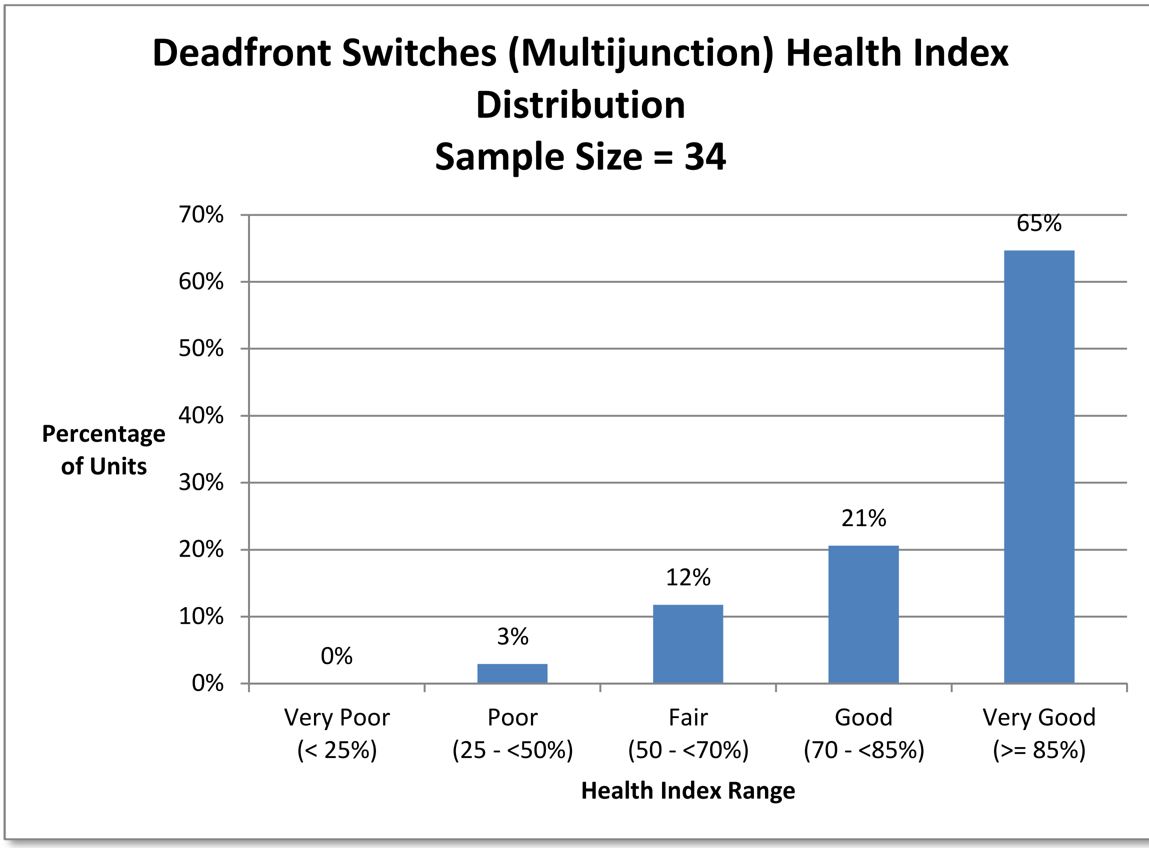


Figure 12-4 Multijunctions Health Index Distribution (Percentage of Units)

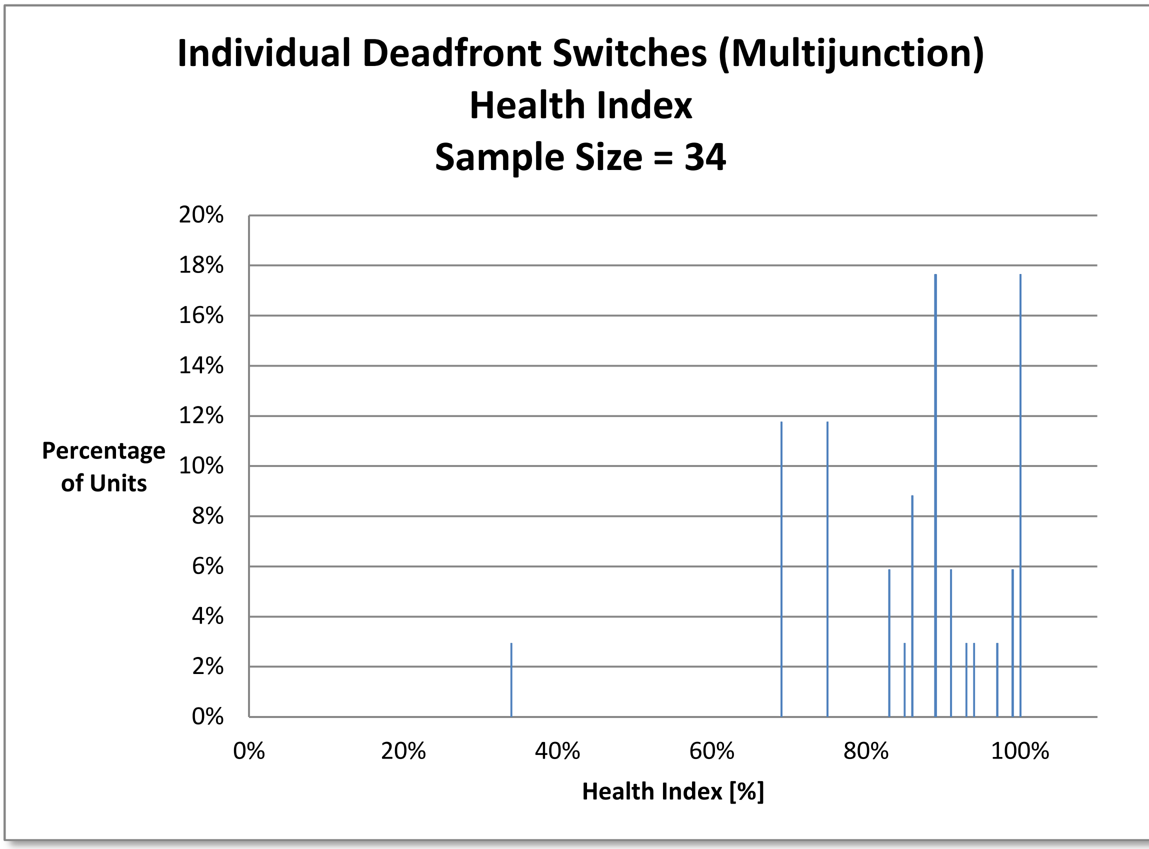


Figure 12-5 Multijunctions Health Index Distribution by Value (Percentage of Units)

12.4 Condition-Based Flagged for Action Plan

As it is assumed that Multijunctions are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

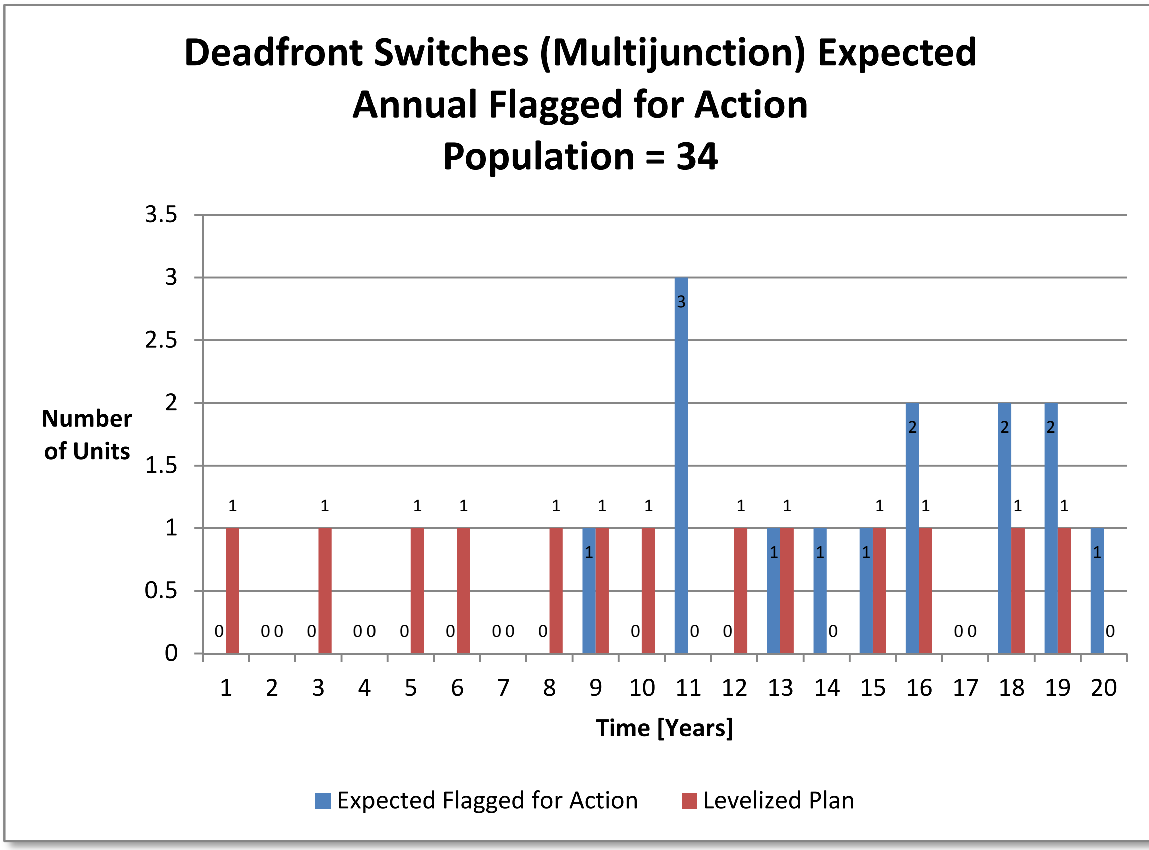


Figure 12-6 Multijunctions Condition-Based Flagged for Action Plan

12.5 Data Analysis

12.5.1 Data Gap

The only data available for Multijunctions was age only. Data gaps identified are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Connection	Connection	✫ ✫	Connections	Loose connections	Visual inspection
Overall	Service Record	✫ ✫ ✫	Unit	General status evaluation based on routine operation and inspection	Visual Inspection

12.5.2 Data Availability Distribution

Because only age is known for this asset category, the average DAI for Multijunctions is 17%.

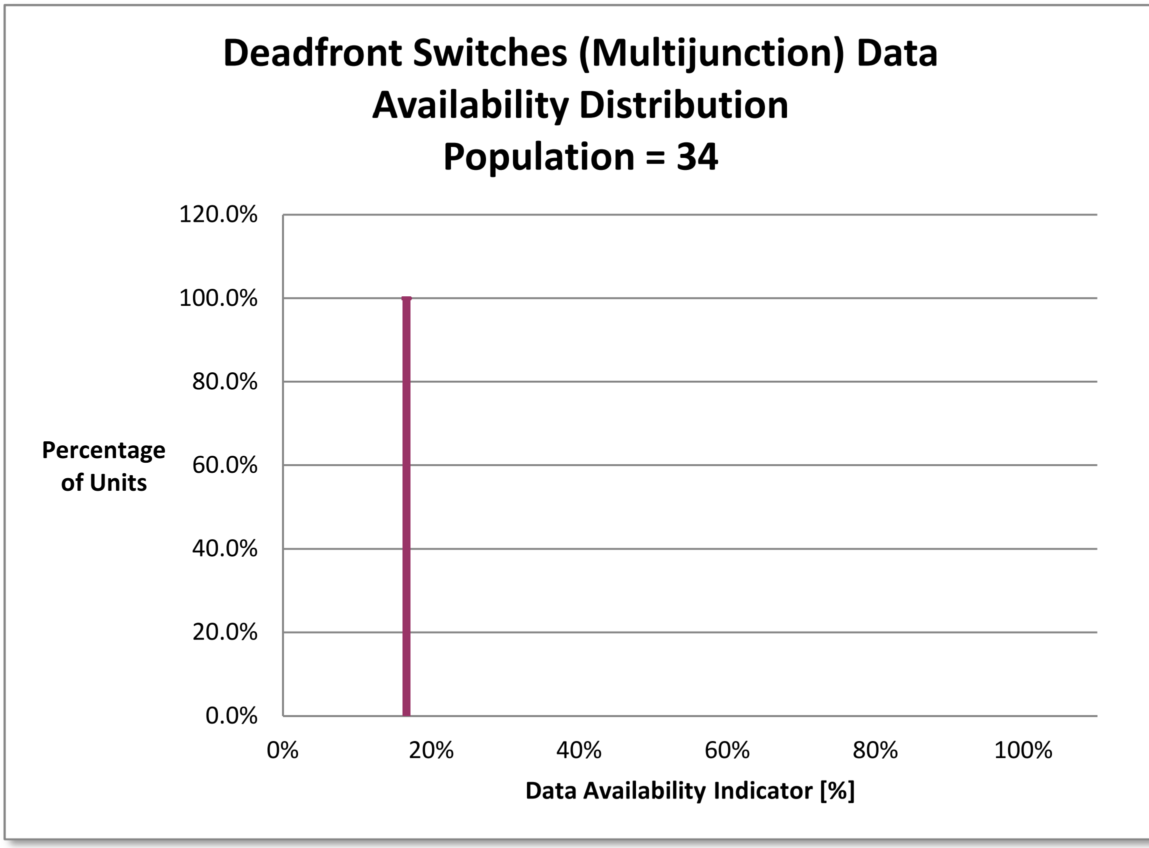


Figure 12-7 Multijunctions Data Availability Distribution

13 Primary Cables

13.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Primary Cables. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

13.1.1 Condition and Sub-Condition Parameters

Table 13-1 Primary Cables Condition Weights and Maximum CPS

<table>
<tr><th>Condition Parameter</th><th>Condition Parameter Weight</th><th>Sub-Condition Parameter</th><th>Sub-Condition Parameter Weight</th><th>Criteria Lookup Table</th></tr>
<tr><td rowspan="2">Physical Condition</td><td rowspan="2">1</td><td>Splices and Terminations</td><td>1</td><td></td></tr>
<tr><td>Overall Corrective Maintenance Counts</td><td>1</td><td></td></tr>
<tr><td>Operation Condition</td><td>3</td><td>Loading</td><td>1</td><td></td></tr>
<tr><td rowspan="2">Service Record</td><td rowspan="2">4</td><td>5 Year Fault Rate</td><td>4</td><td></td></tr>
<tr><td>Age</td><td>3</td><td>Figure 13-2</td></tr>
<tr><td colspan="2">De-Rating Factor</td><td>Pre 1980 vintage</td><td colspan="2">80%</td></tr>
</table>

13.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Primary Cables 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 failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

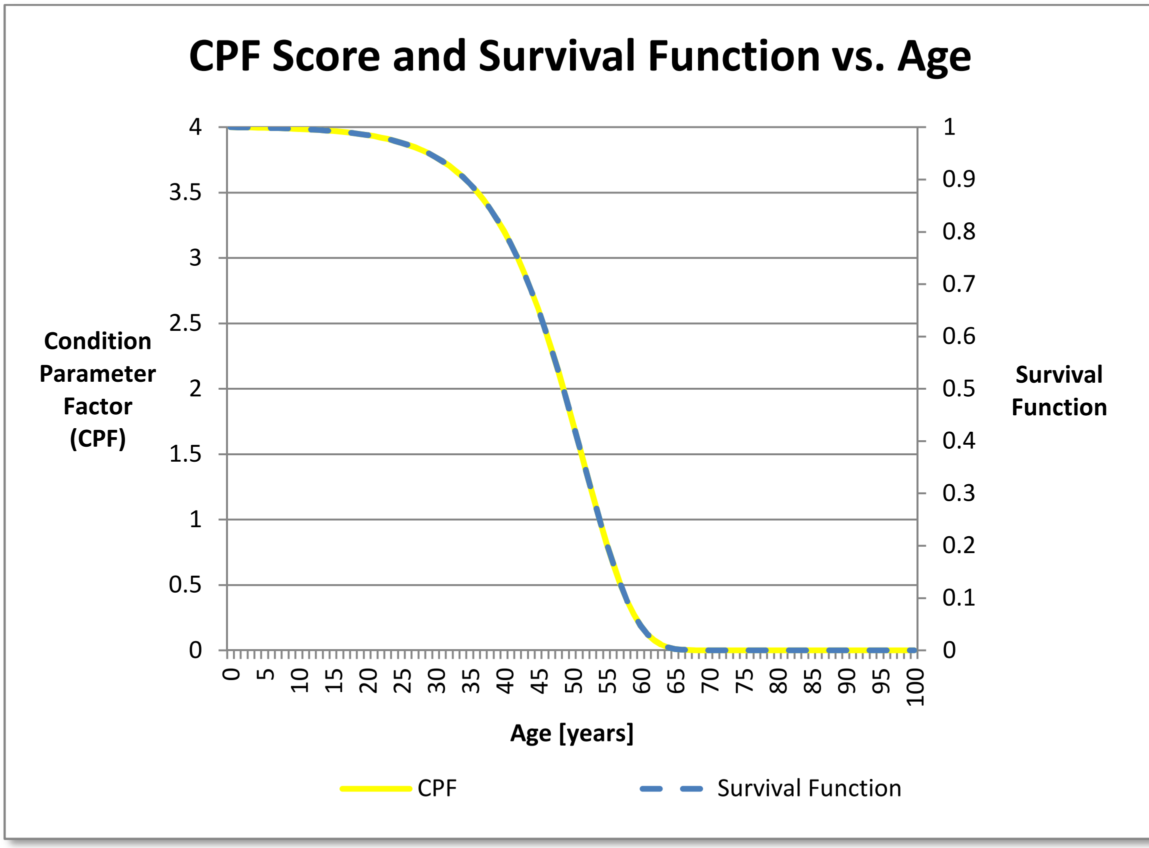


Figure 13-1 Primary Cables Age Condition Criteria

13.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 16 years.

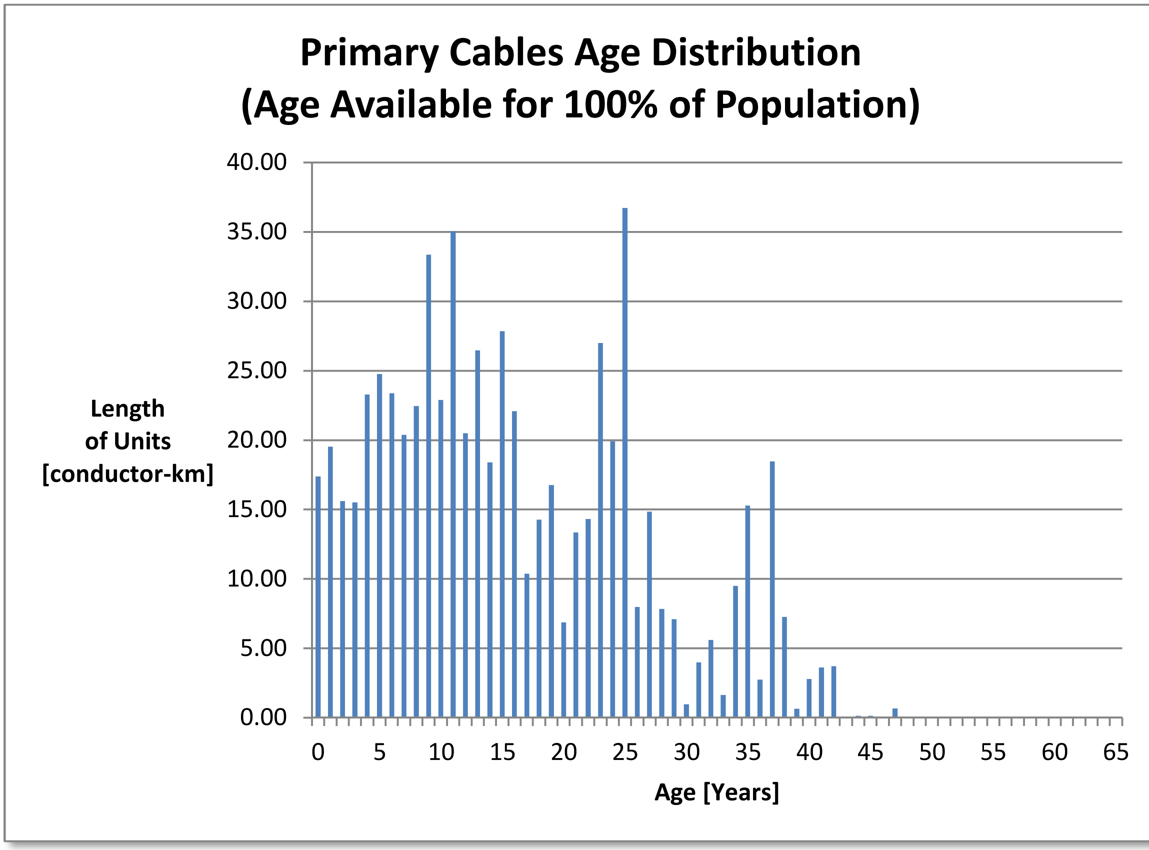


Figure 13-2 Primary Cables Age Distribution

13.3 Health Index Results

There are 663 conductor-km of in-service Primary Cables at GHESI. There were 663 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 96%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

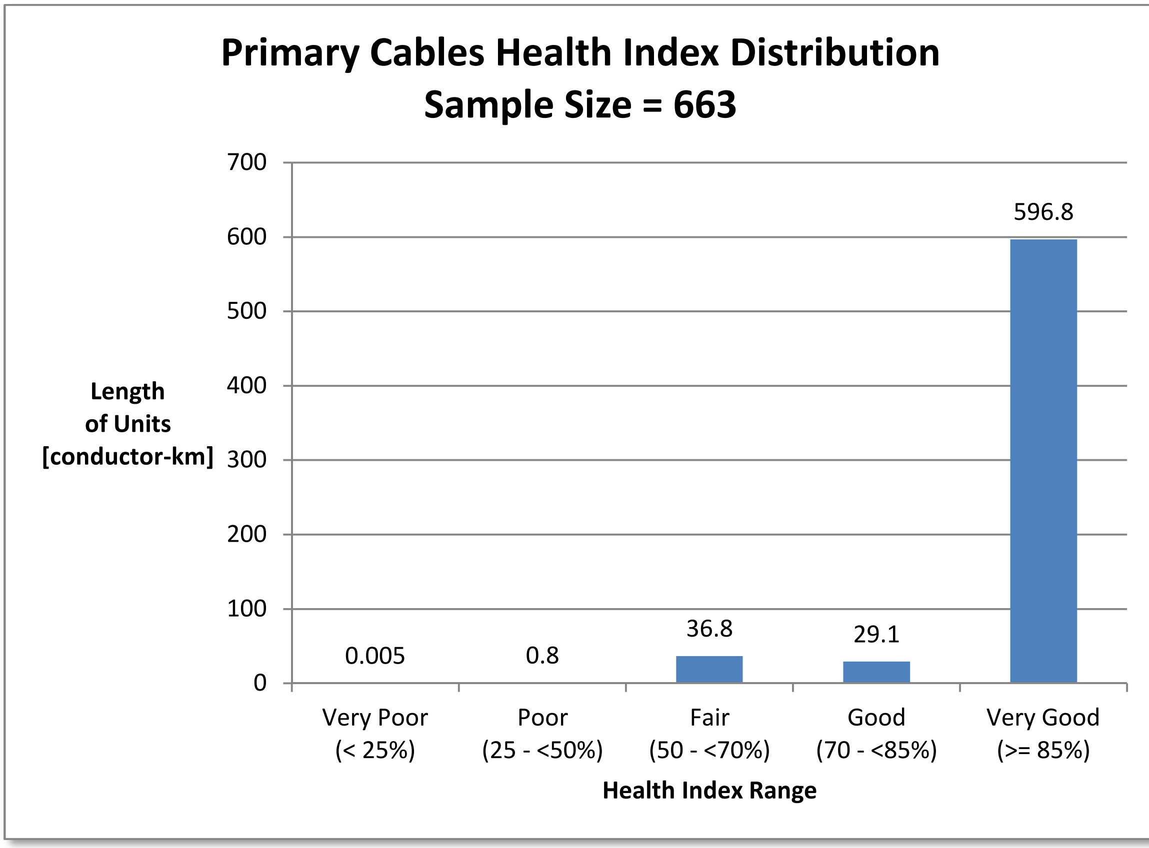


Figure 13-3 Primary Cables Health Index Distribution (Number of Units)

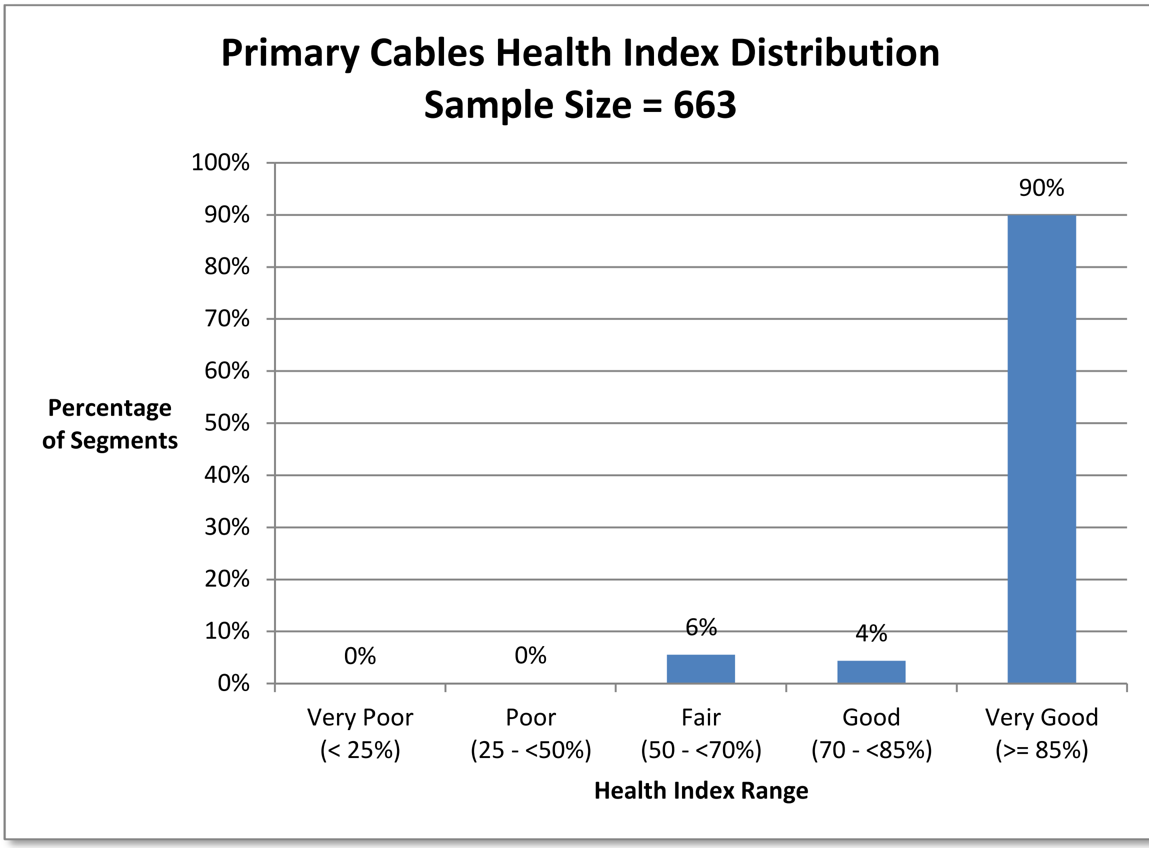


Figure 13-4 Primary Cables Health Index Distribution (Percentage of Units)

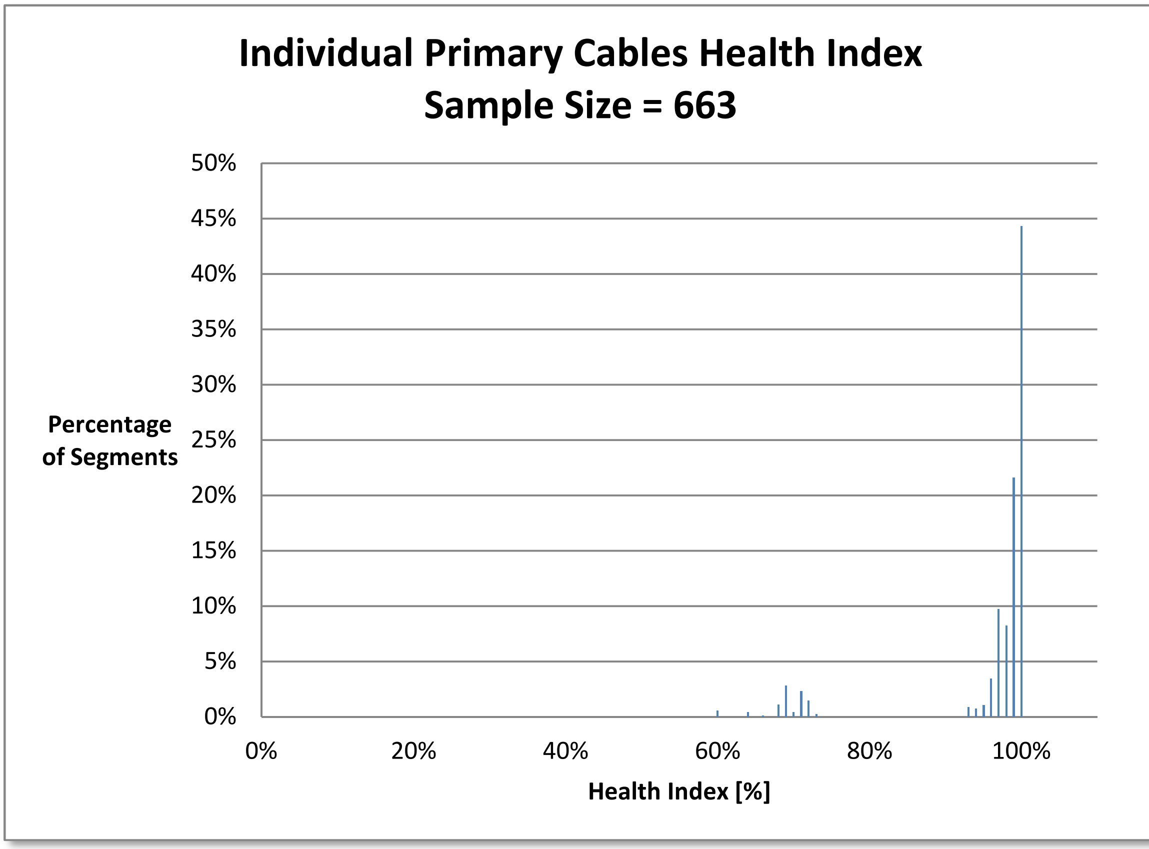


Figure 13-5 Primary Cables Health Index Distribution by Value (Percentage of Units)

13.4 Condition-Based Flagged for Action Plan

As it is assumed that Primary Cables are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

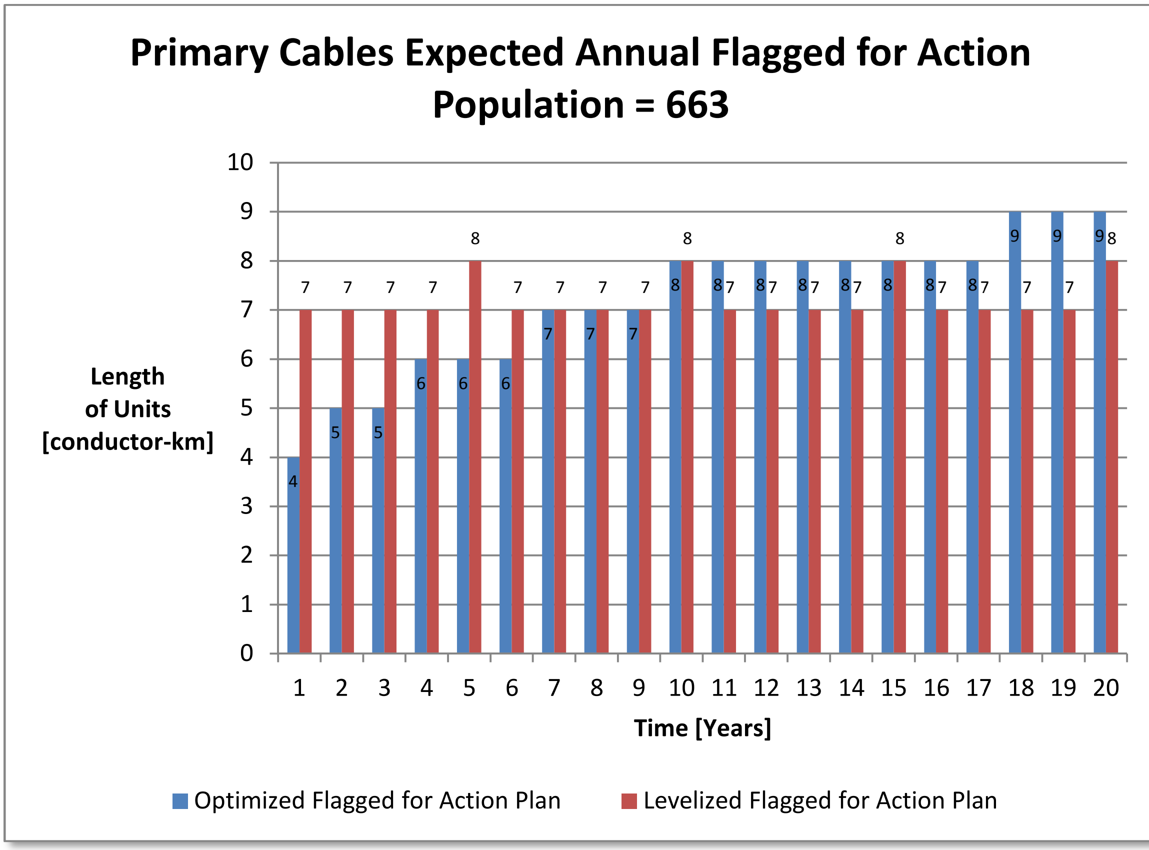


Figure 13-6 Primary Cables Condition-Based Flagged for Action Plan

13.5 Data Analysis

13.5.1 Data Gap

Only age was available for Primary Cables.

<table>
<tr><th>Data Gap (Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td rowspan="5">Splice & Termination</td><td rowspan="6">Physical Condition</td><td rowspan="5">☆☆</td><td rowspan="3">Cable splice</td><td>Under/over-compressed connector</td><td rowspan="5">On-site visual inspection</td></tr>
<tr><td>Improper ground connection</td></tr>
<tr><td>Loose bolt</td></tr>
<tr><td rowspan="2">Cable termination</td><td>Sealing issue</td></tr>
<tr><td>Insulation erosion</td></tr>
<tr><td>Overall</td><td>☆☆</td><td>Cable segment</td><td>Count of total corrective maintenance work orders issued on cable segment during a specific time window</td><td>Operation record</td></tr>
<tr><td>Loading</td><td>Operation Condition</td><td>☆☆☆</td><td>Cable segment</td><td>Loading History: e.g. hourly peak Loads</td><td>Operation record</td></tr>
</table>

13.5.2 Data Availability Distribution

Because only age was available, the average DAI for Primary Cables is 21%.

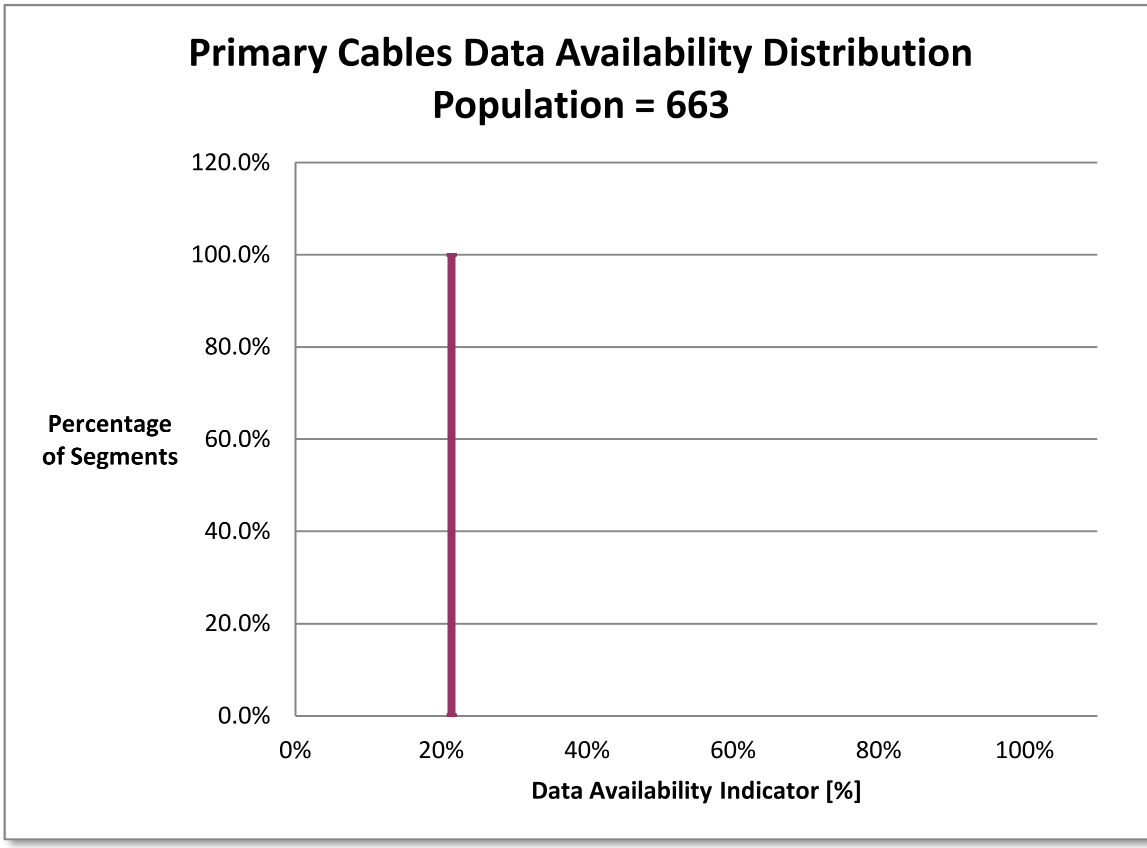


Figure 13-7 Primary Cables Data Availability Distribution

14 Secondary Cables

14.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Secondary Cables. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

14.1.1 Condition and Sub-Condition Parameters

Table 14-1 Secondary Cables Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Splices and Terminations	1	
		Overall Corrective Maintenance Counts	1	
Operation Condition	3	Loading	1	
Service Record	4	5 Year Fault Rate	4	
		Age	3	Figure 14-1

14.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Secondary Cables 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 failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

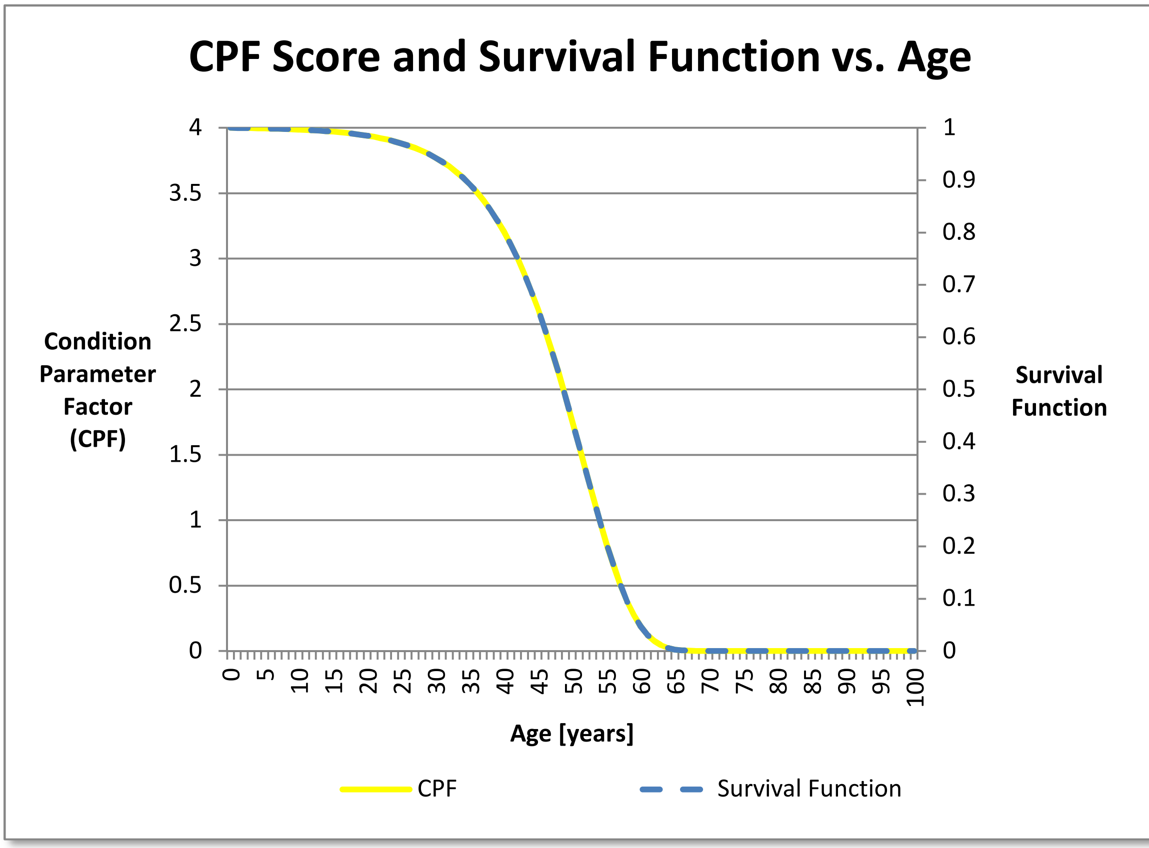


Figure 14-1 Secondary Cables Age Condition Criteria

14.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 17 years.

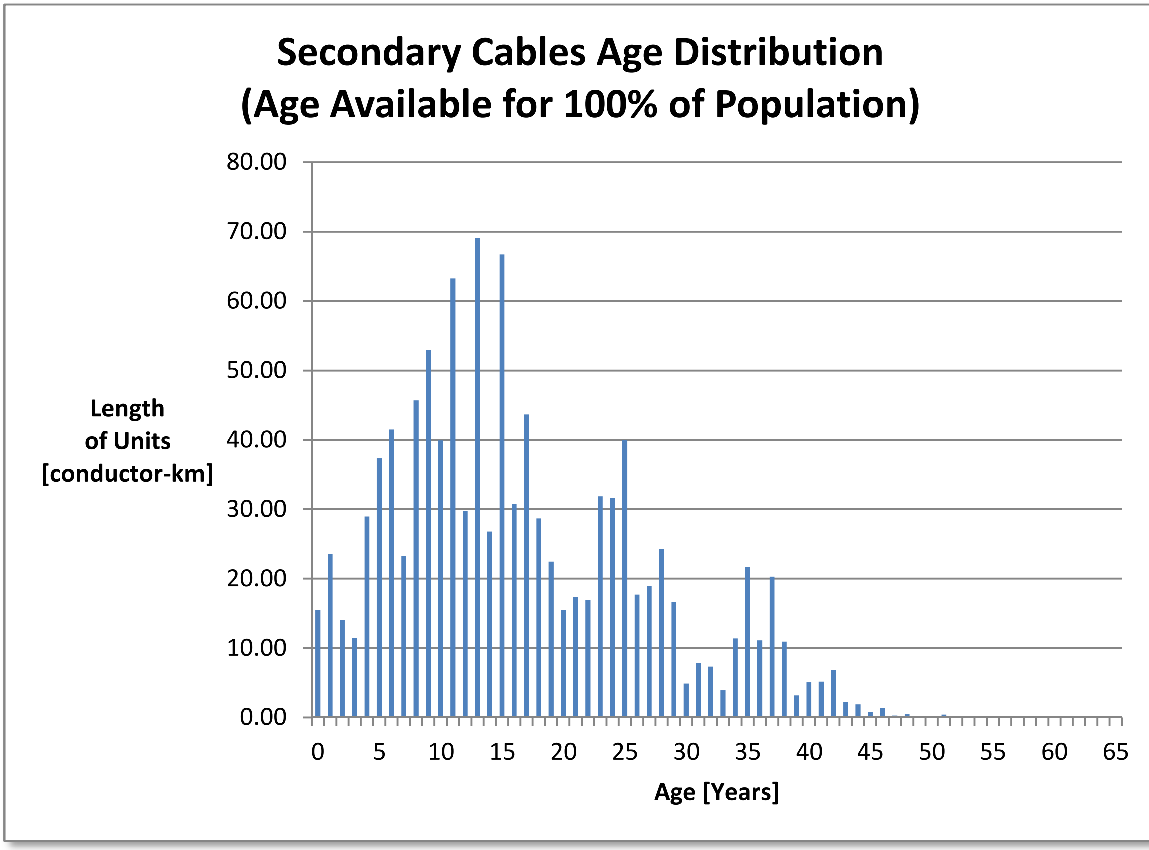


Figure 14-2 Secondary Cables Age Distribution

14.3 Health Index Results

There are 1074 conductor-km of in-service Secondary Cables at GHESI. There was 1074 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 97%. Approximately <1% of the units were found to be in poor condition.

The Health Index Results are as follows:

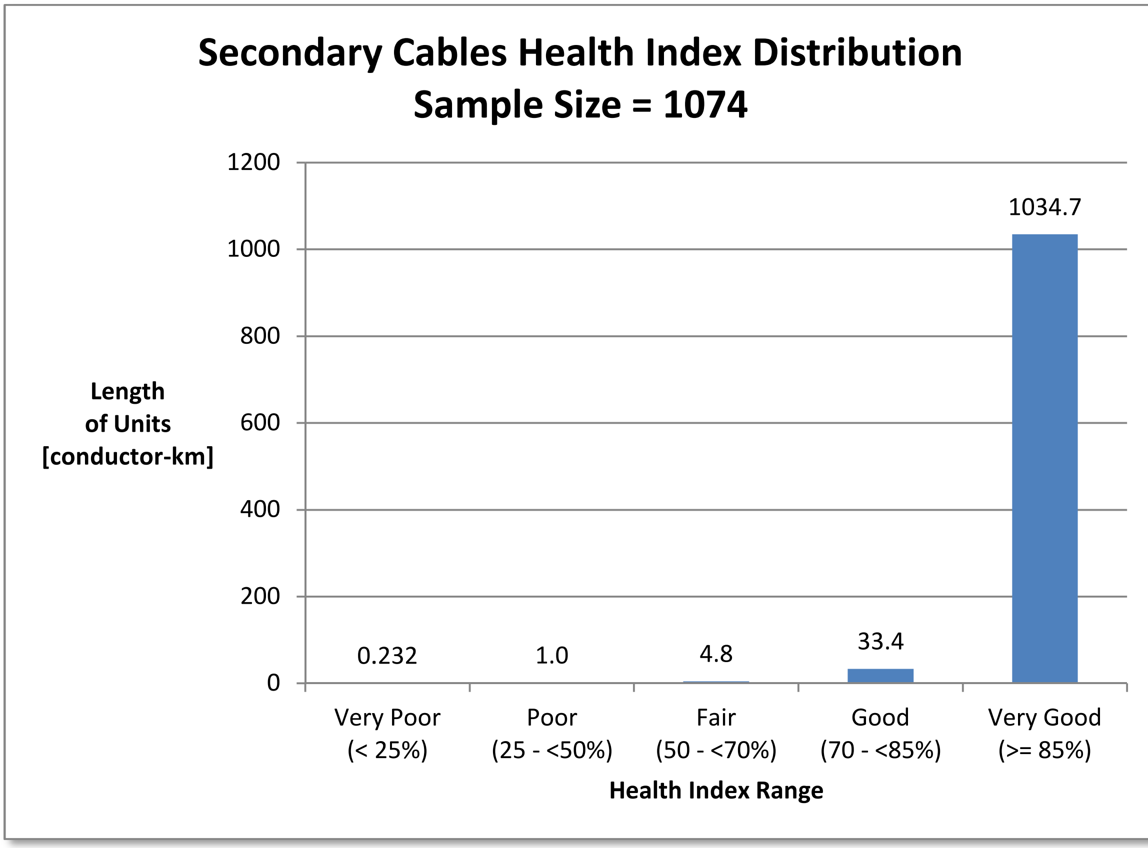


Figure 14-3 Secondary Cables Health Index Distribution (Number of Units)

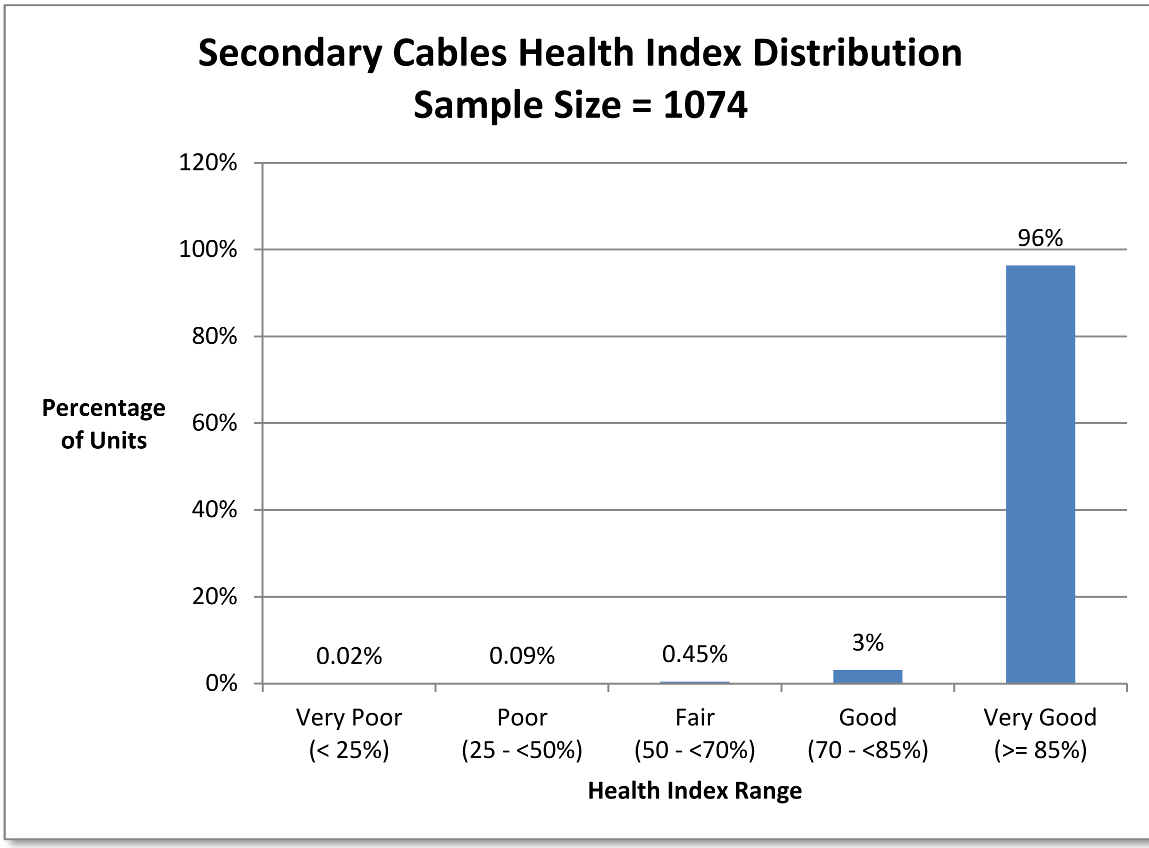


Figure 14-4 Secondary Cables Health Index Distribution (Percentage of Units)

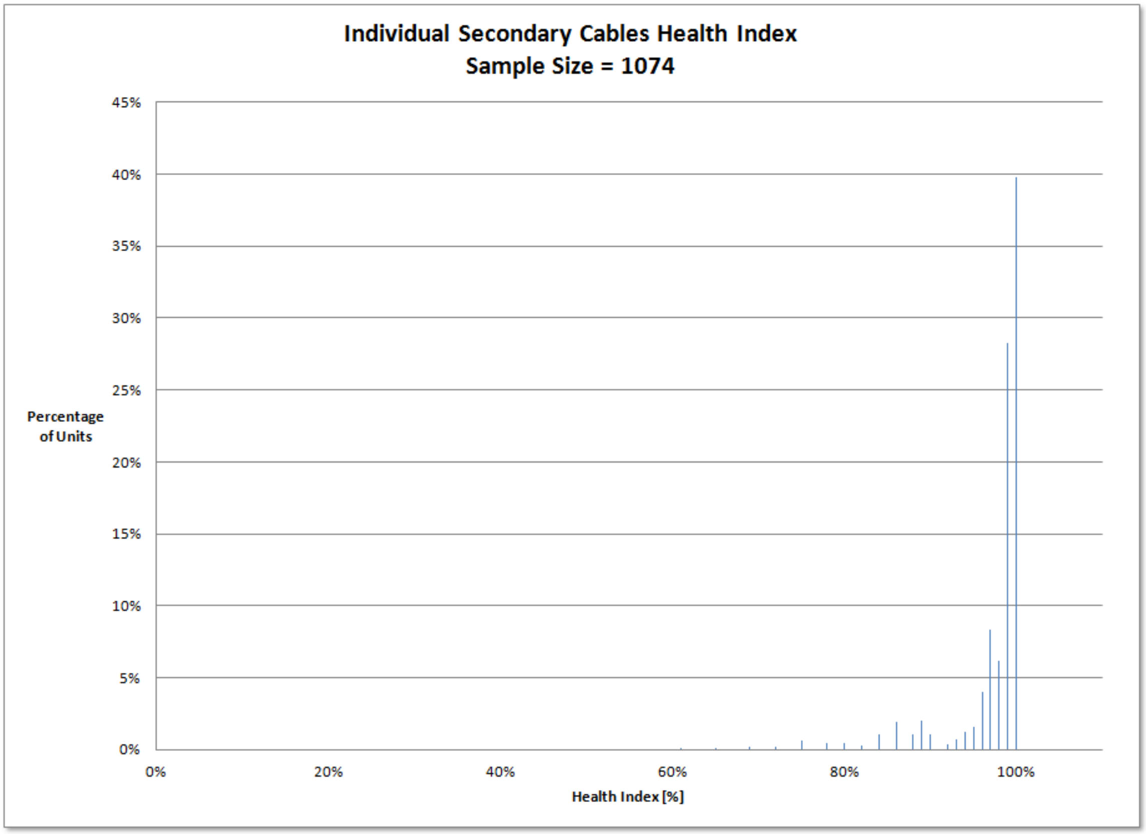


Figure 14-5 Secondary Cables Health Index Distribution by Value (Percentage of Units)

14.4 Condition-Based Flagged for Action Plan

As it is assumed that Secondary Cables are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a “levelized” plan, based on accelerating or replacing prior to expected time of action, is also given.

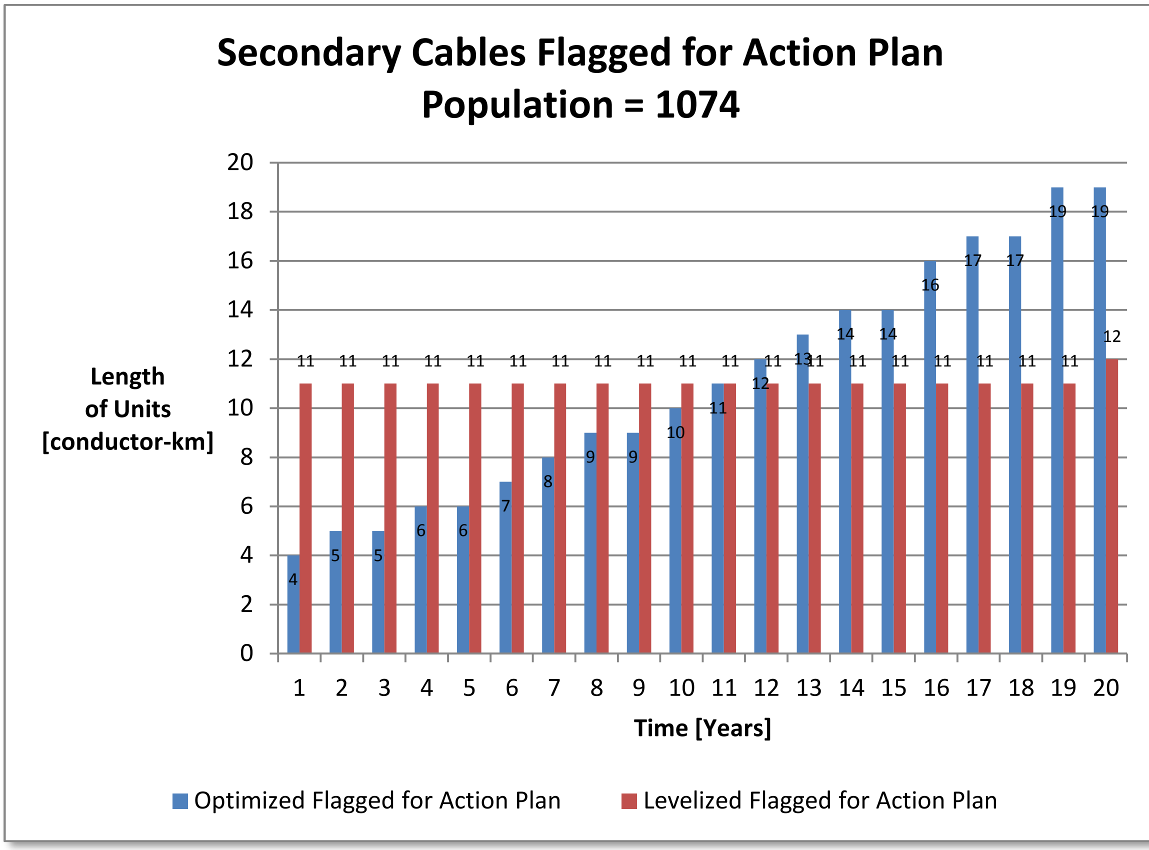


Figure 14-6 Secondary Cables Condition-Based Flagged for Action Plan

14.5 Data Analysis

14.5.1 Data Gap

Only age was available for Secondary Cables.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Splice & Termination	Physical Condition	☆ ☆	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		☆ ☆	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record
Loading	Operation Condition	☆ ☆ ☆	Cable segment	Loading History: e.g. hourly peak Loads	Operation record

14.5.2 Data Availability Distribution

Because only age was available, the average, the average DAI for Secondary Cables is 21%.

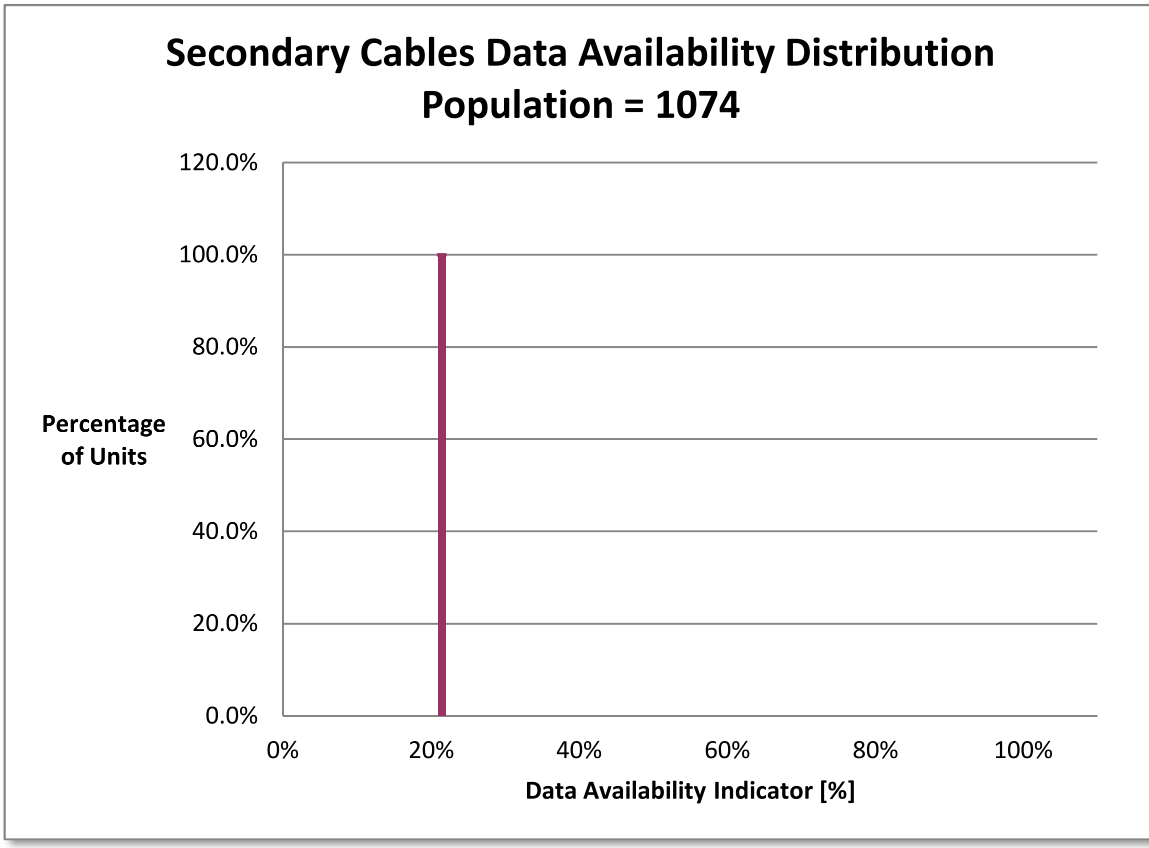


Figure 14-7 Secondary Cables Data Availability Distribution

15 Single Phase Primary Lines

15.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Single Phase Primary Lines. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

15.1.1 Condition and Sub-Condition Parameters

Table 15-1 Single Phase Primary Lines Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Repairs / Splices	1	
		Overall Corrective Maintenance Counts	1	
Service Record	1	Overall Condition	4	
		Age	3	Figure 15-1

15.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Single Phase Primary Lines 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 60 and 77 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

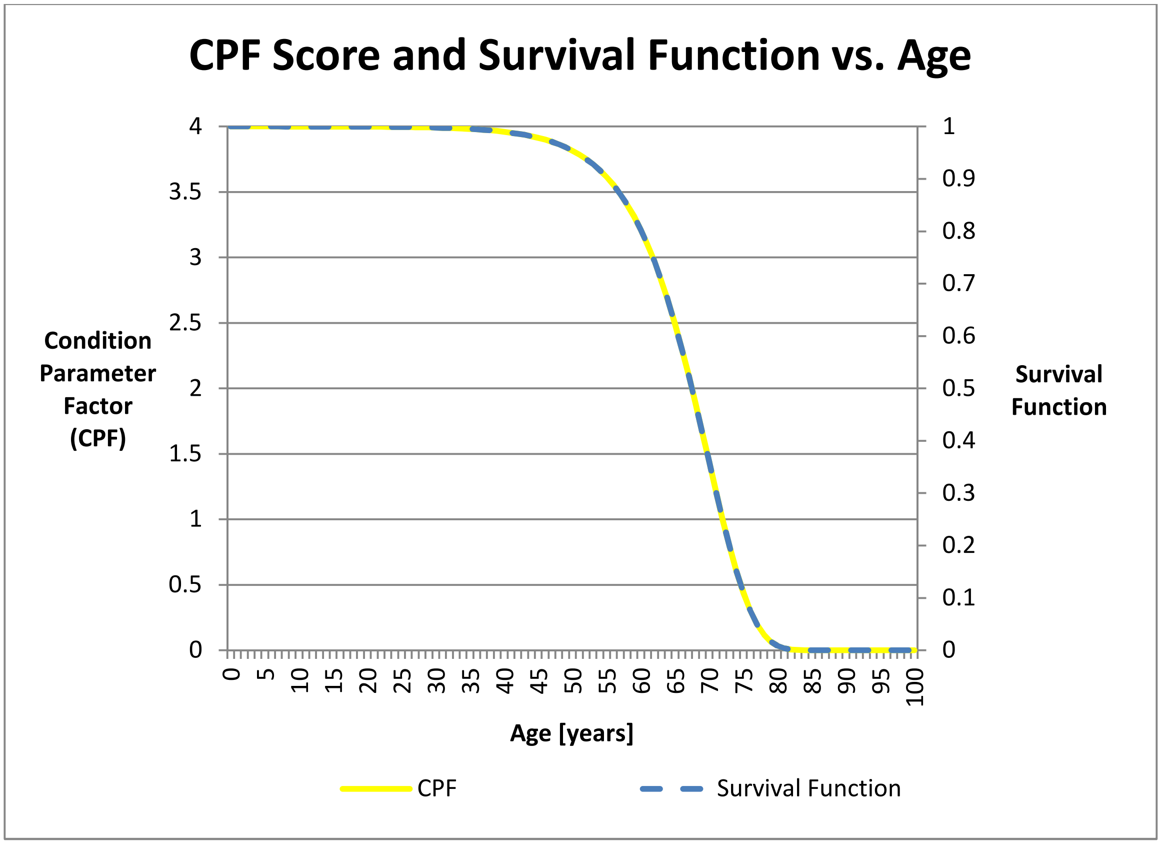


Figure 15-1 Single Phase Primary Lines Age Condition Criteria

15.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 27 years.

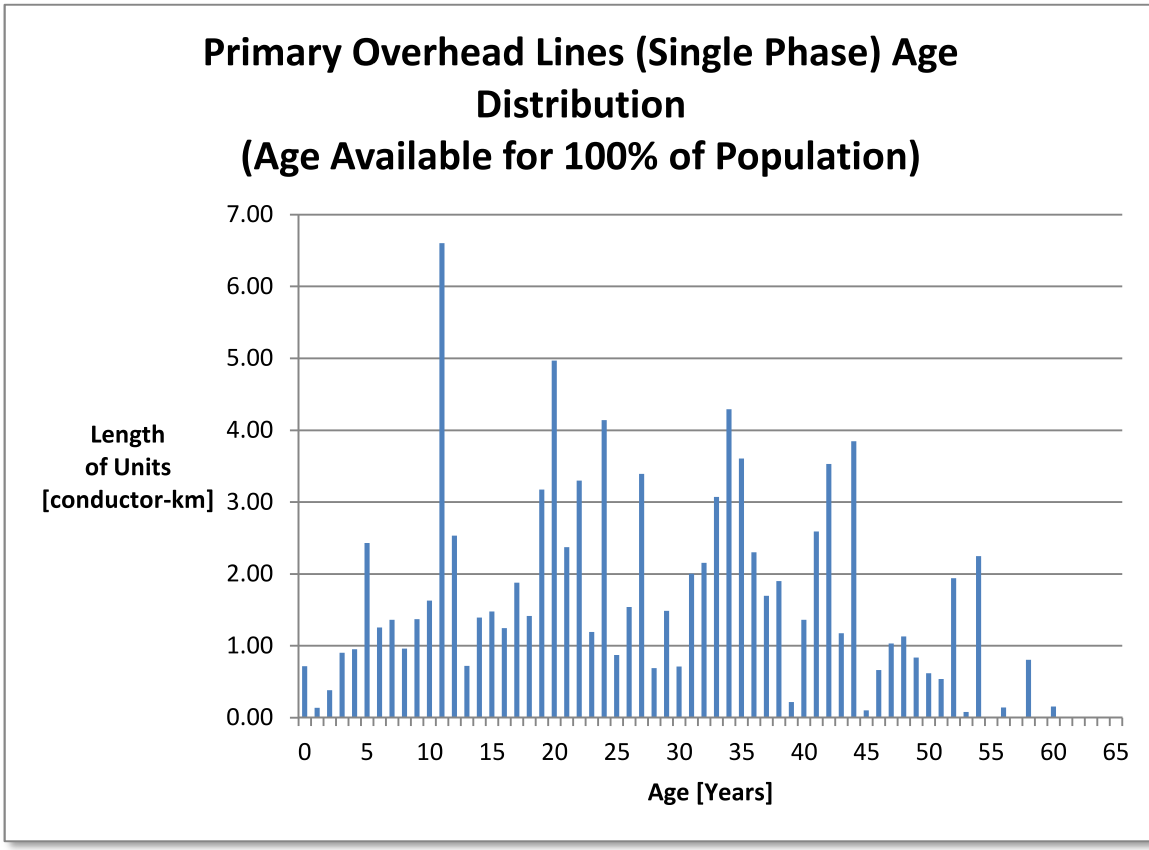


Figure 15-2 Single Phase Primary Lines Age Distribution

15.3 Health Index Results

There are 101 conductor-km of in-service Single Phase Primary Lines at GHESI. There were 101 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 99%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

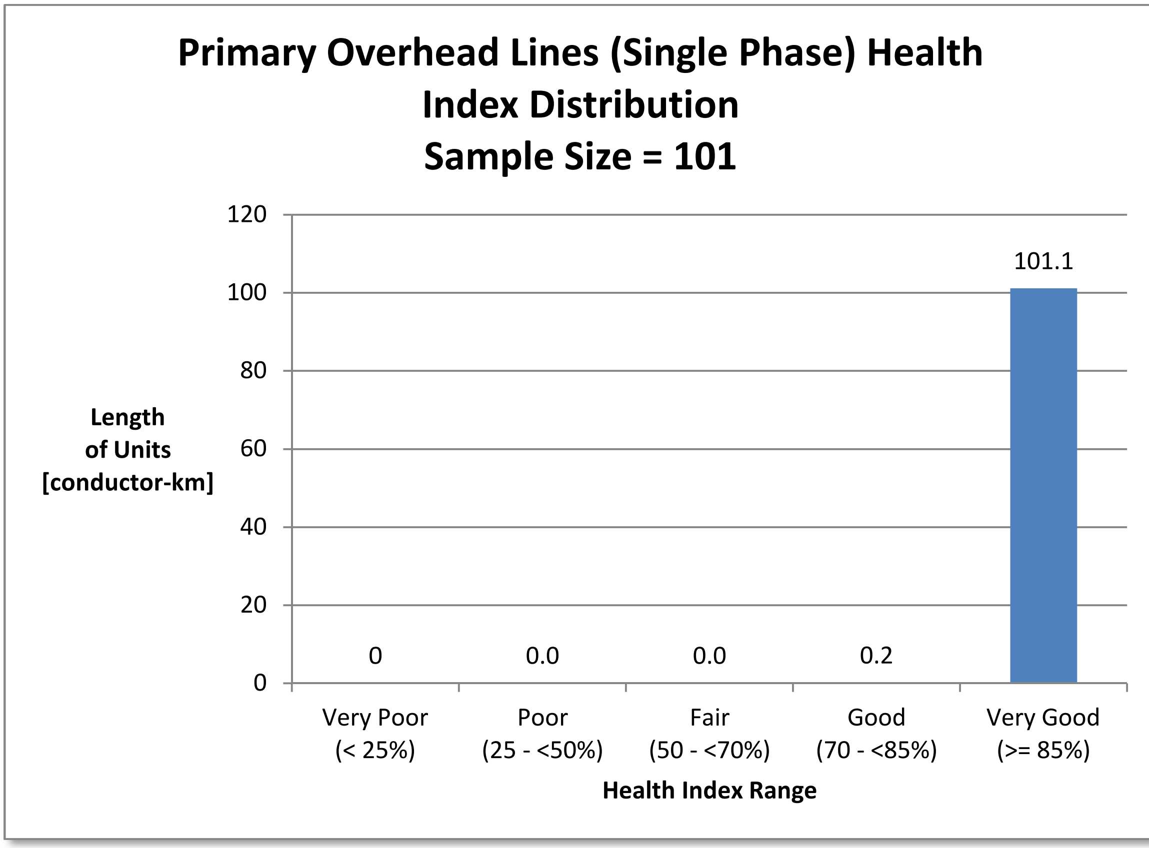


Figure 15-3 Single Phase Primary Lines Health Index Distribution (Number of Units)

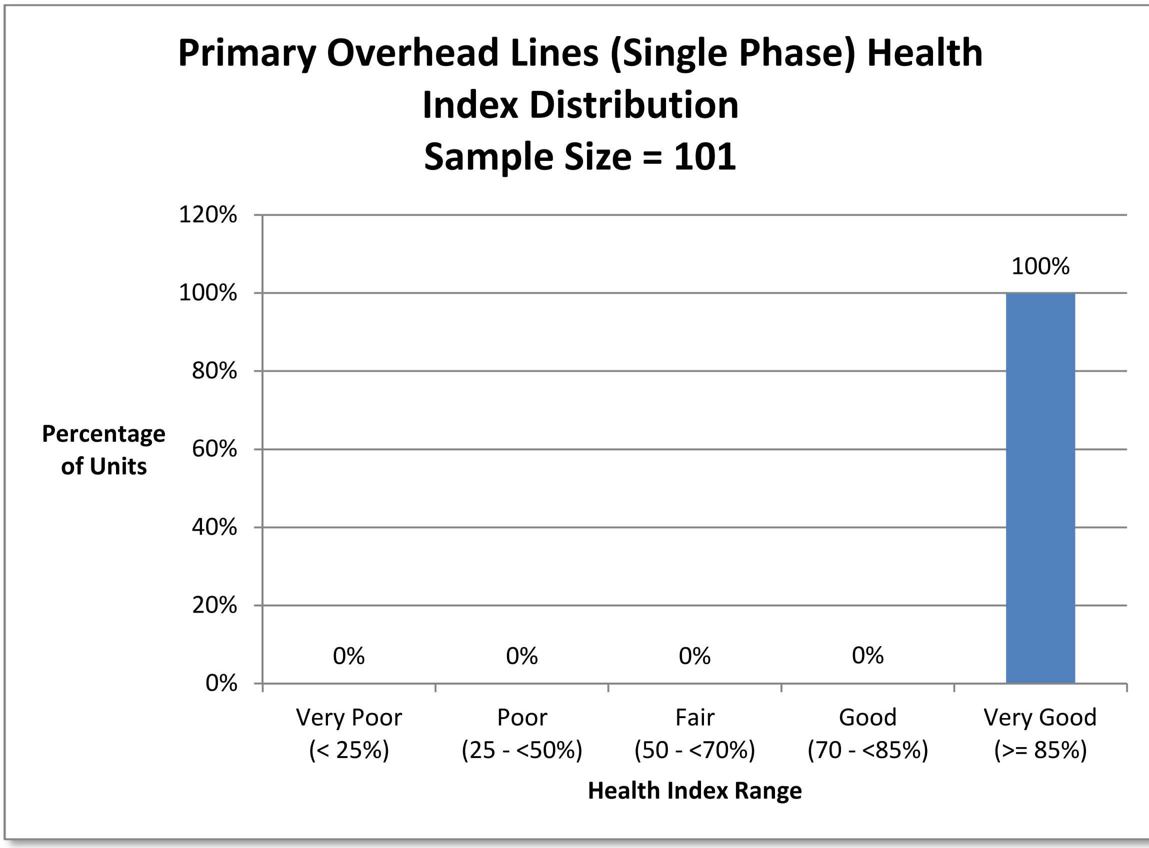


Figure 15-4 Single Phase Primary Lines Health Index Distribution (Percentage of Units)

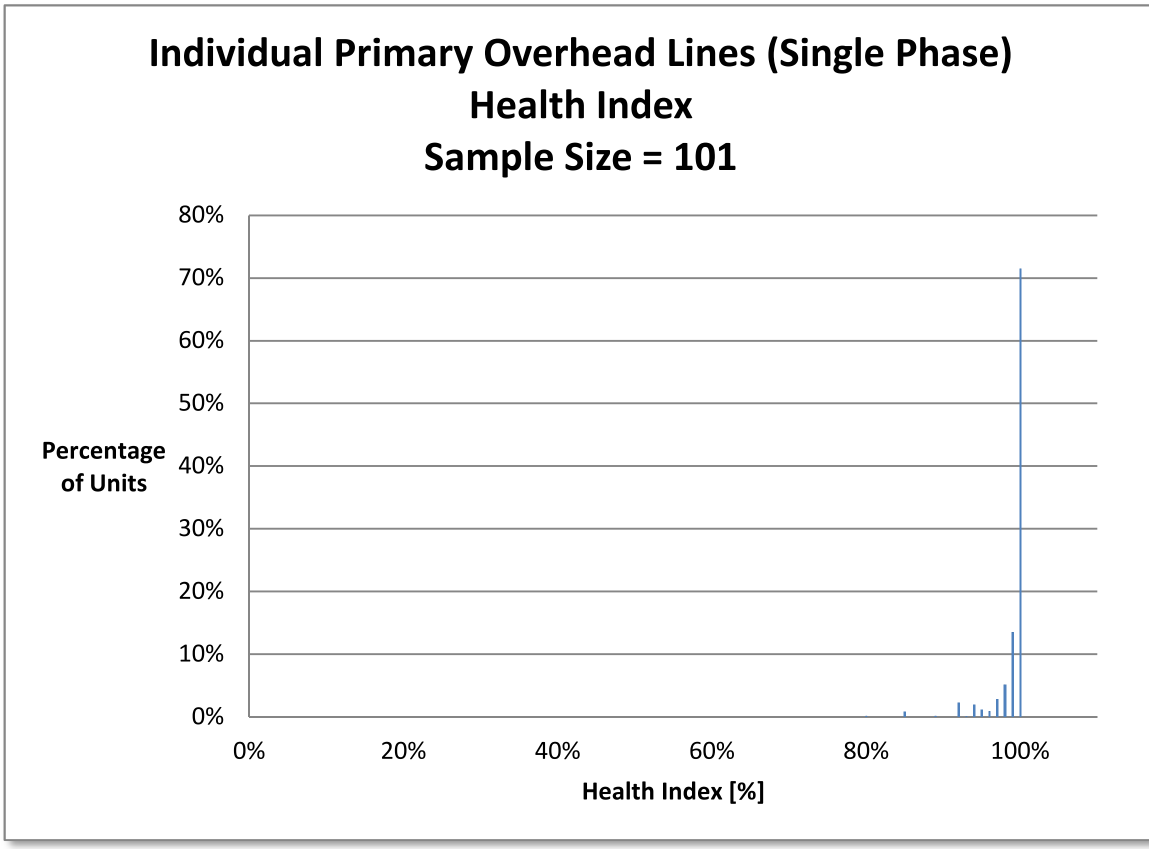


Figure 15-5 Single Phase Primary Lines Health Index Distribution by Value (Percentage of Units)

15.4 Condition-Based Flagged for Action Plan

As it is assumed that Single Phase Primary Lines are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

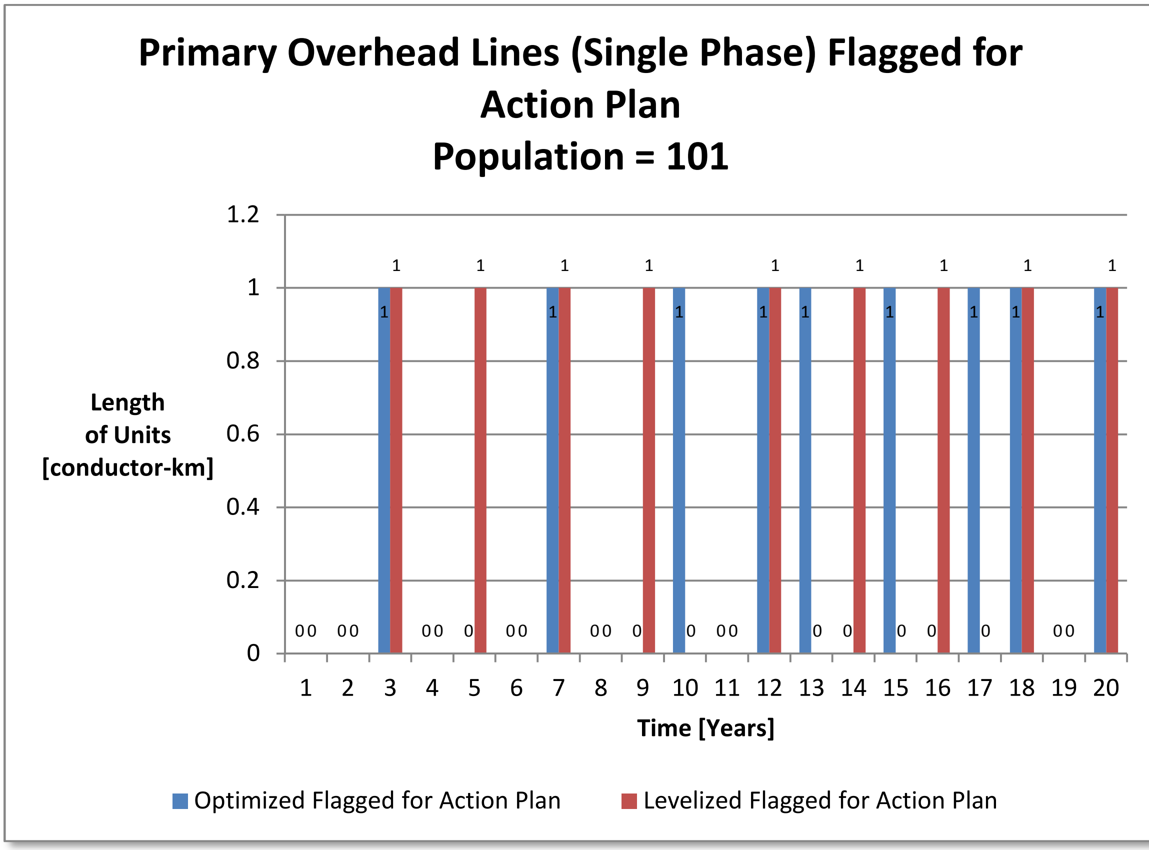


Figure 15-6 Single Phase Primary Lines Condition-Based Flagged for Action Plan

15.5 Data Analysis

15.5.1 Data Gap

Age was the only data available for Single Phase Primary Lines. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Repairs / Splices	Physical Condition	☆☆	Splices or Repairs	Faulty repair or splice	On-site visual inspection
Overall		☆☆	Line Section	Count of total corrective maintenance work orders issued on line section during a specific time window	Operation record

15.5.2 Data Availability Distribution

The average DAI for Single Phase Primary Lines is 21%.

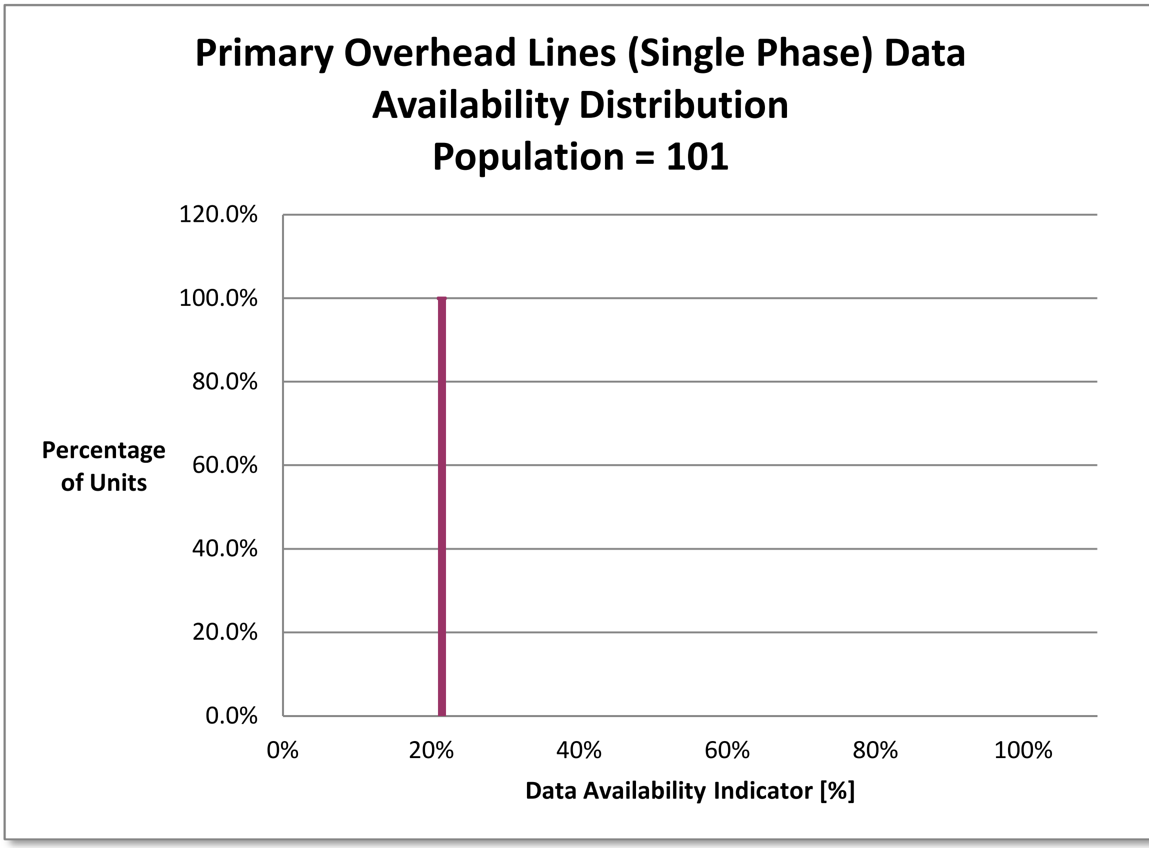


Figure 15-7 Single Phase Primary Lines Data Availability Distribution

16 Three Phase Primary Lines

16.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Three Phase Primary Lines. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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”.

16.1.1 Condition and Sub-Condition Parameters

Table 16-1 Three Phase Primary Lines Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Repairs / Splices	1	
		Overall Corrective Maintenance Counts	1	
Service Record	1	Overall Condition	4	
		Age	3	Figure 16-1

16.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Three Phase Primary Lines 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 60 and 77 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

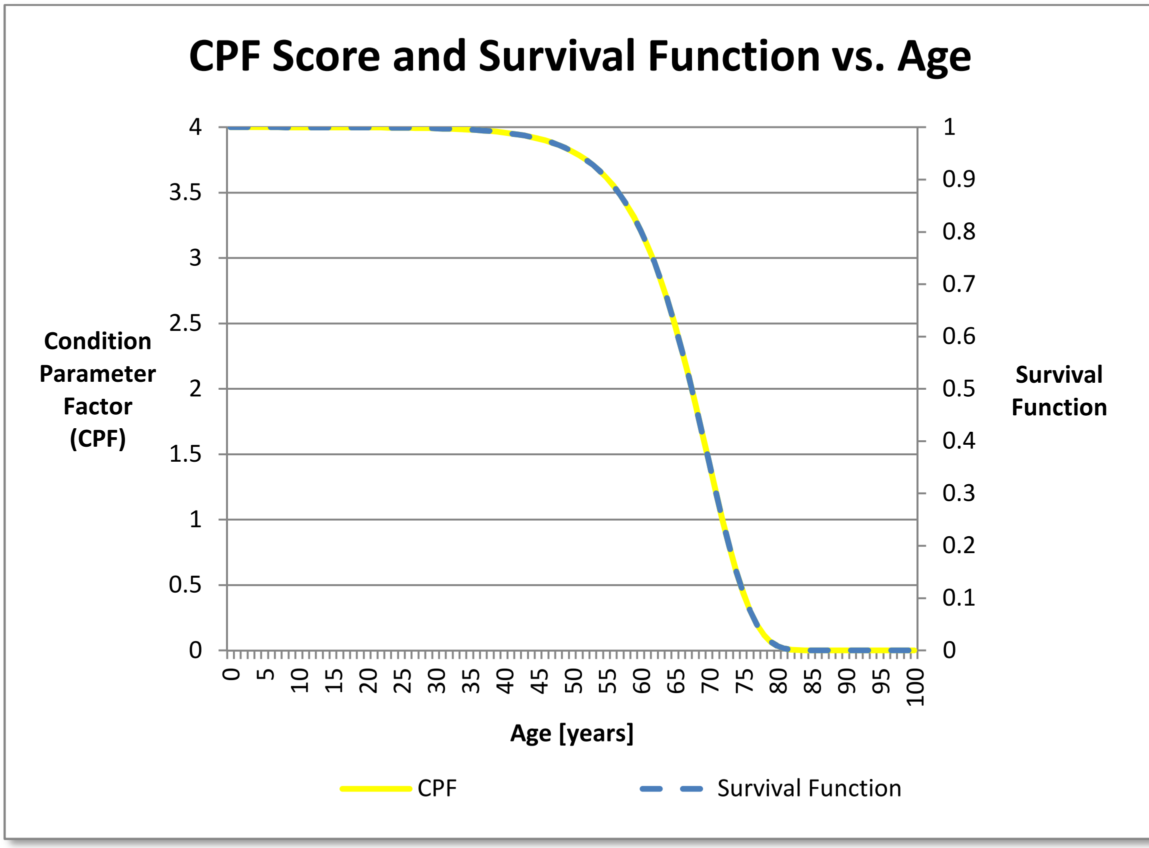


Figure 16-1 Three Phase Primary Lines Age Condition Criteria

16.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 18 years.

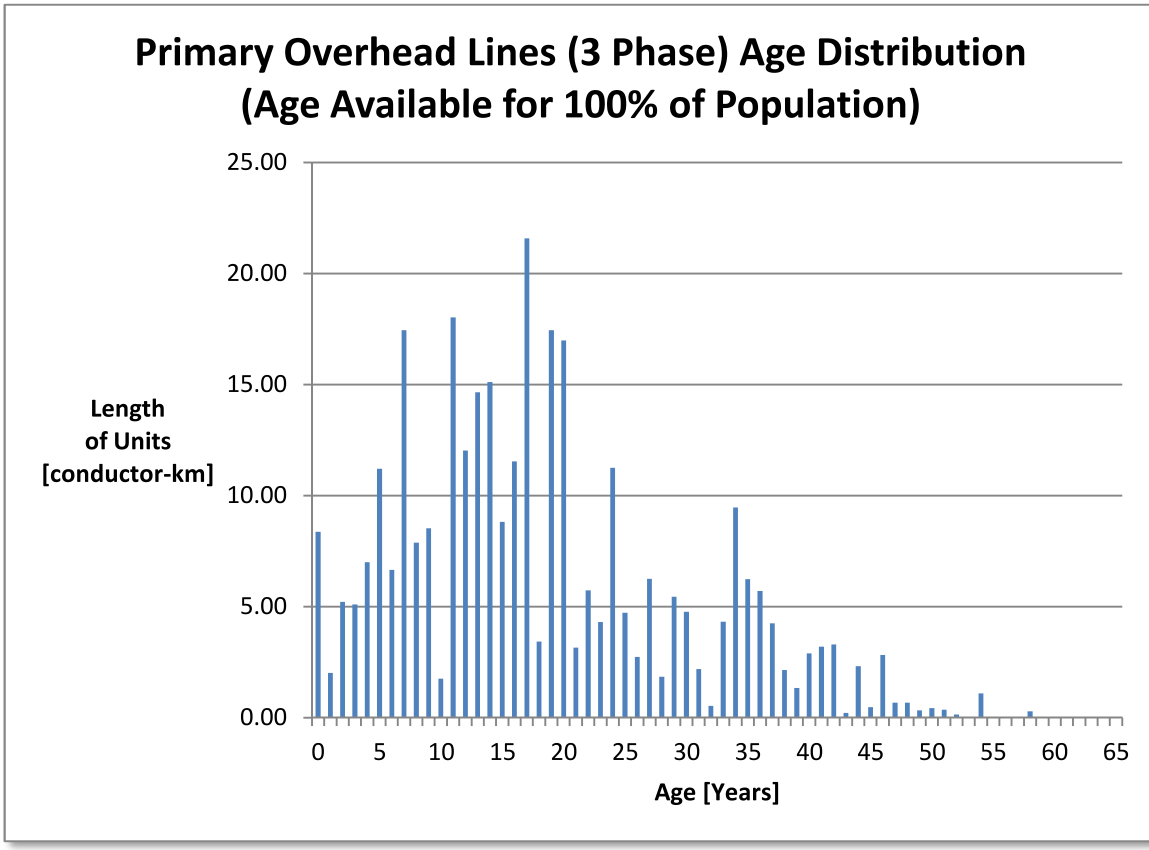


Figure 16-2 Three Phase Primary Lines Age Distribution

16.3 Health Index Results

There are 326 conductor-km of in-service Three Phase Primary Lines at GHESI. There were 326 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 100%. None were found to be in poor condition.

The Health Index Results are as follows:

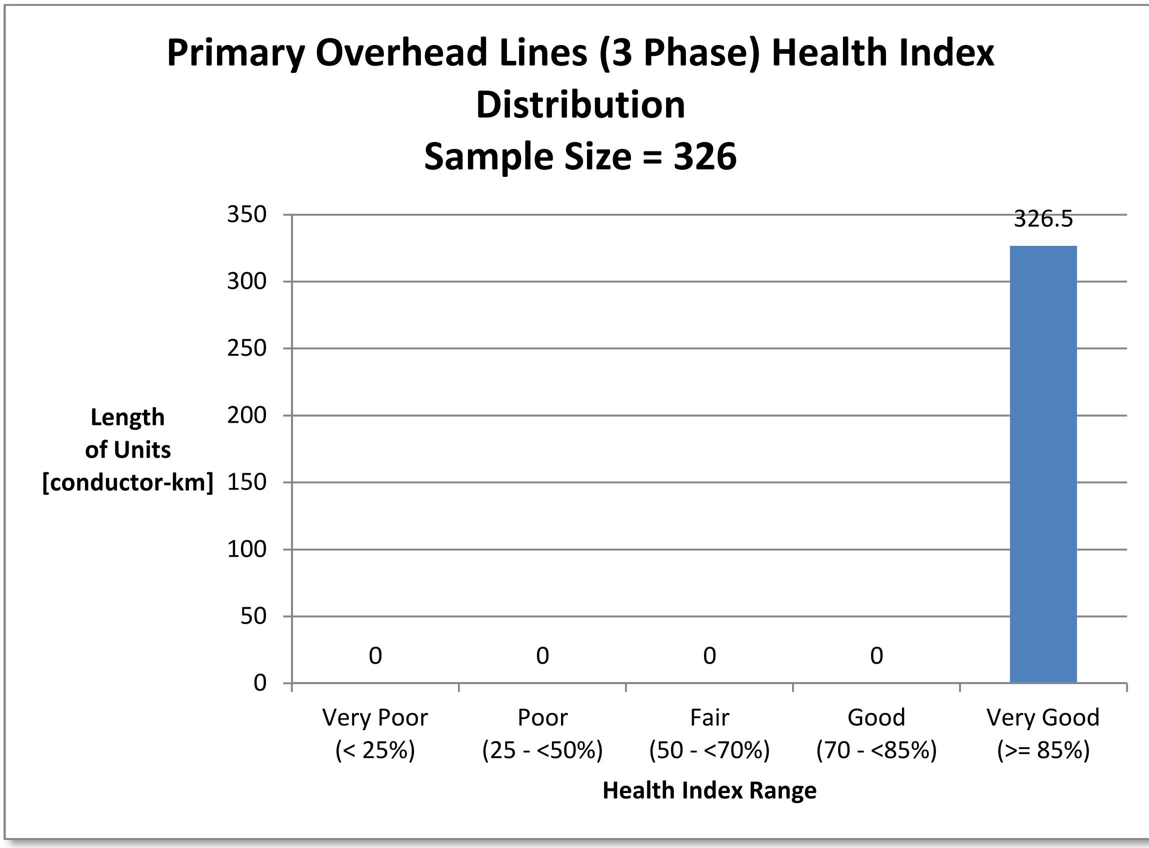


Figure 16-3 Three Phase Primary Lines Health Index Distribution (Number of Units)

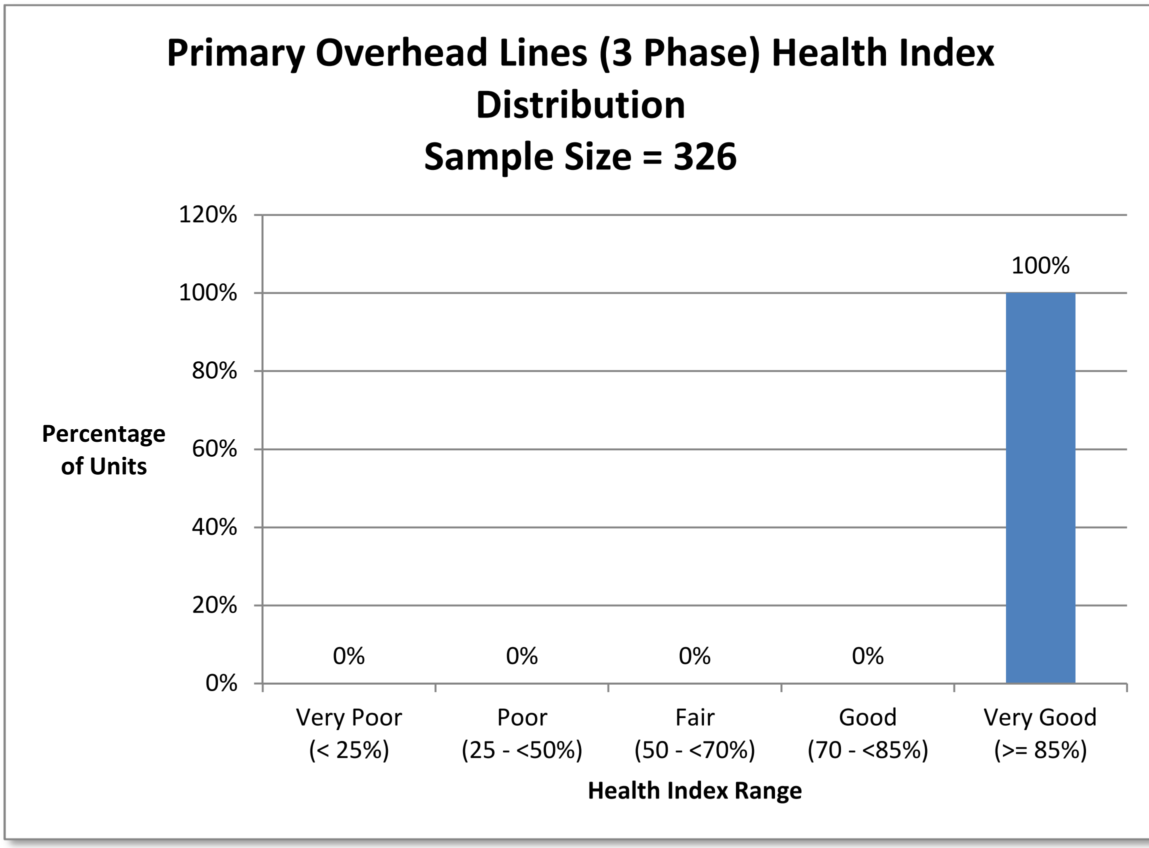


Figure 16-4 Three Phase Primary Lines Health Index Distribution (Percentage of Units)

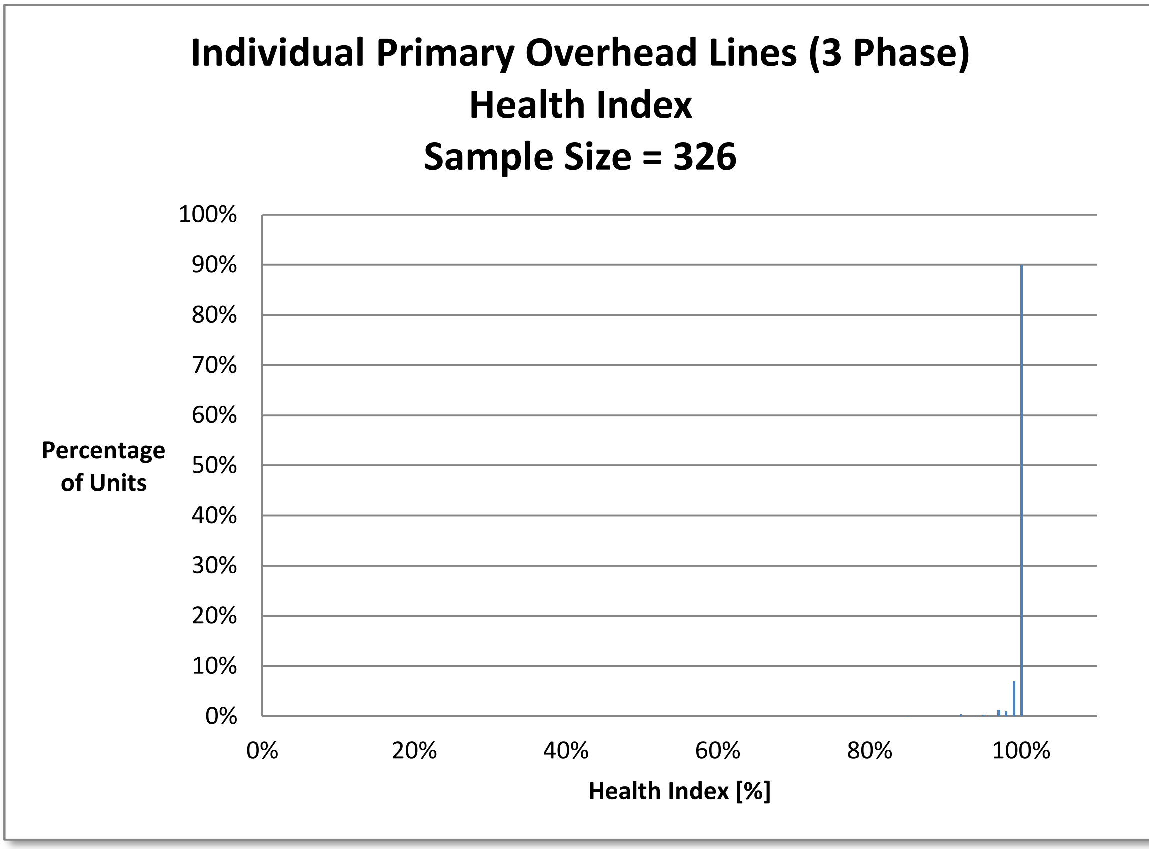


Figure 16-5 Three Phase Primary Lines Health Index Distribution by Value (Percentage of Units)

16.4 Condition-Based Flagged for Action Plan

As it is assumed that Three Phase Primary Lines are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

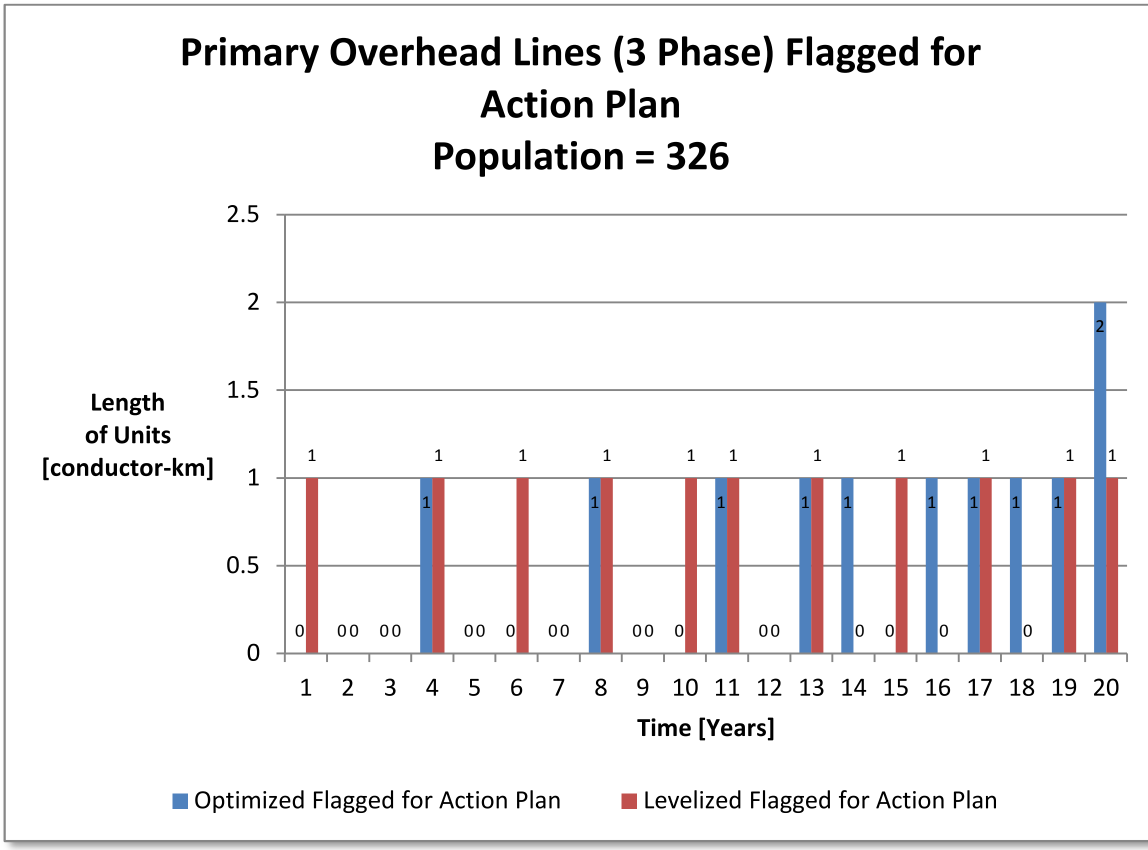


Figure 16-6 Three Phase Primary Lines Condition-Based Flagged for Action Plan

16.5 Data Analysis

16.5.1 Data Gap

The data available for Three Phase Primary Lines was age only. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Repairs / Splices	Physical Condition	☆☆	Splices or Repairs	Faulty repair or splice	On-site visual inspection
Overall		☆☆	Line Section	Count of total corrective maintenance work orders issued on line section during a specific time window	Operation record

16.5.2 Data Availability Distribution

The average DAI for Three Phase Primary Lines is 21%.

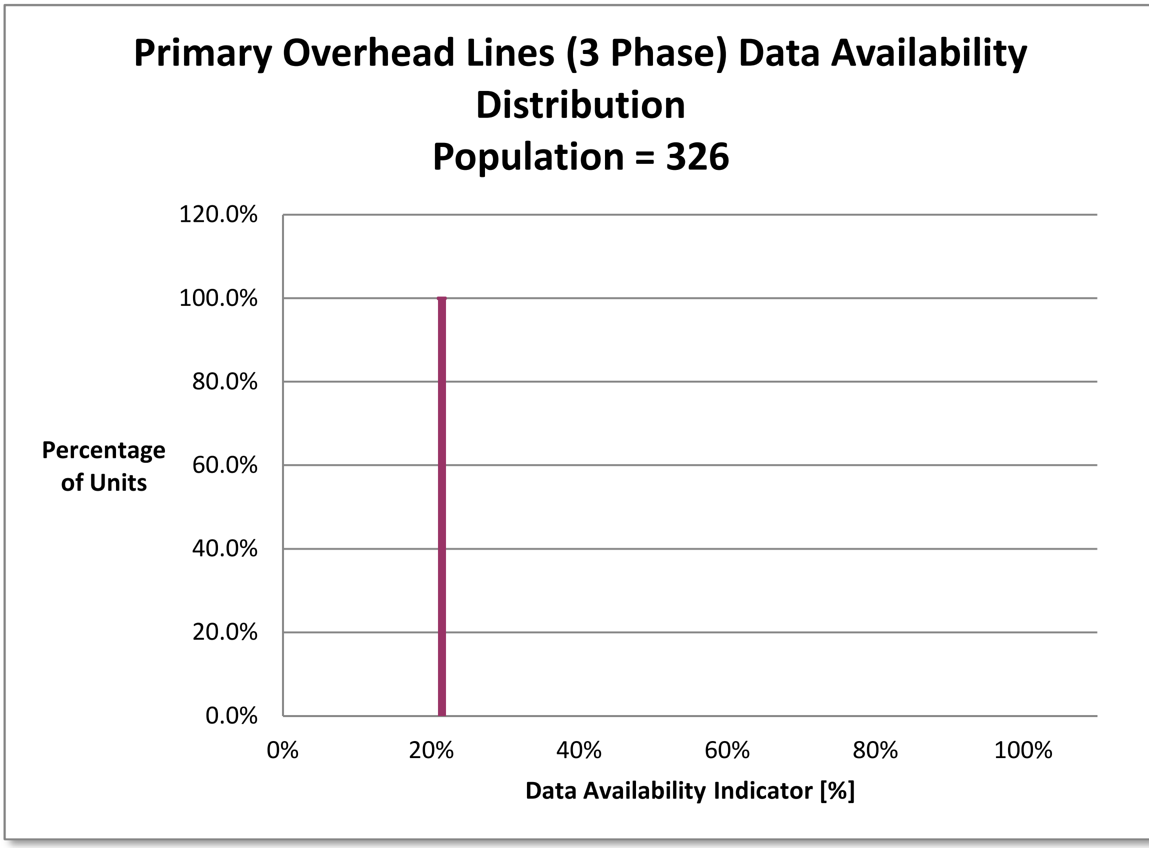


Figure 16-7 Three Phase Primary Lines Data Availability Distribution

17 Secondary Lines

17.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Secondary Lines. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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”.

17.1.1 Condition and Sub-Condition Parameters

Table 17-1 Secondary Lines Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	1	Repairs / Splices	1	
		Overall Corrective Maintenance Counts	1	
Service Record	1	Overall Condition	4	
		Age	3	Figure 17-1

17.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Secondary Lines 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 60 and 77years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

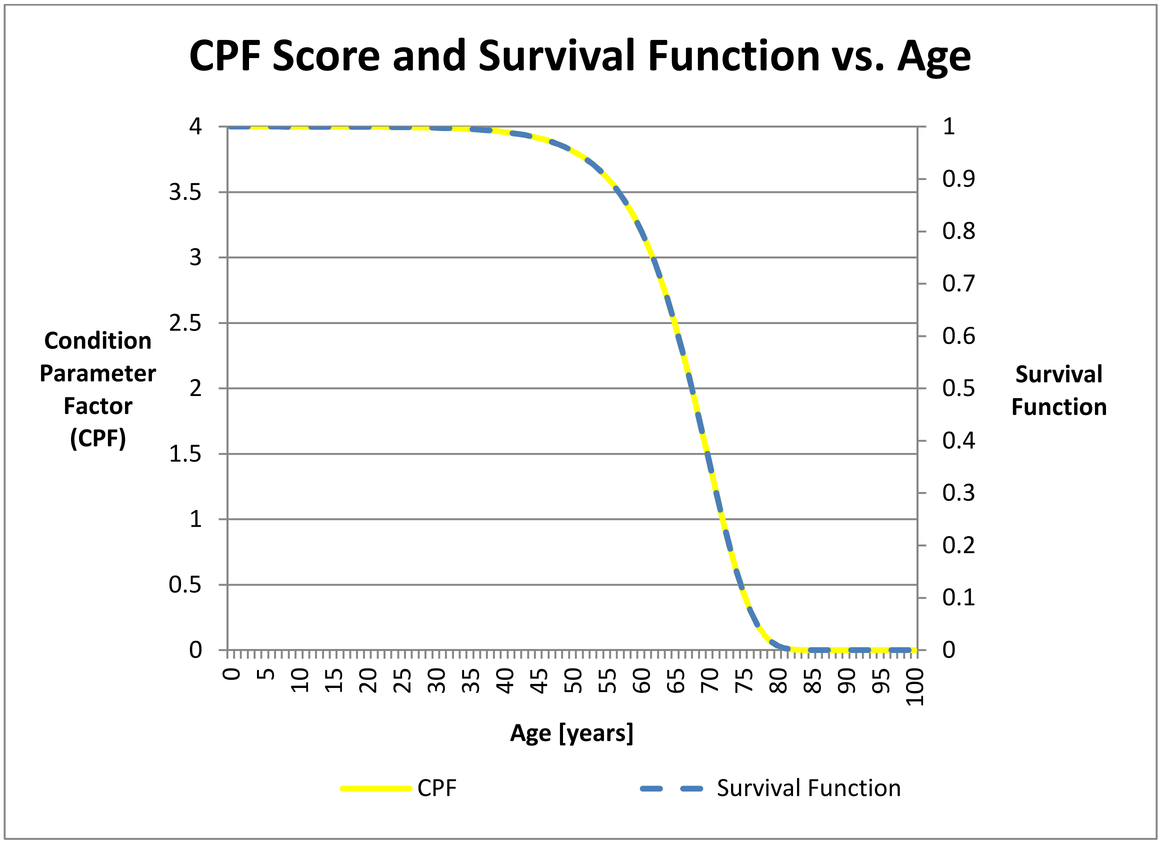


Figure 17-1 Secondary Lines Age Condition Criteria

17.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 98% of the population. The average age was found to be 27 years.

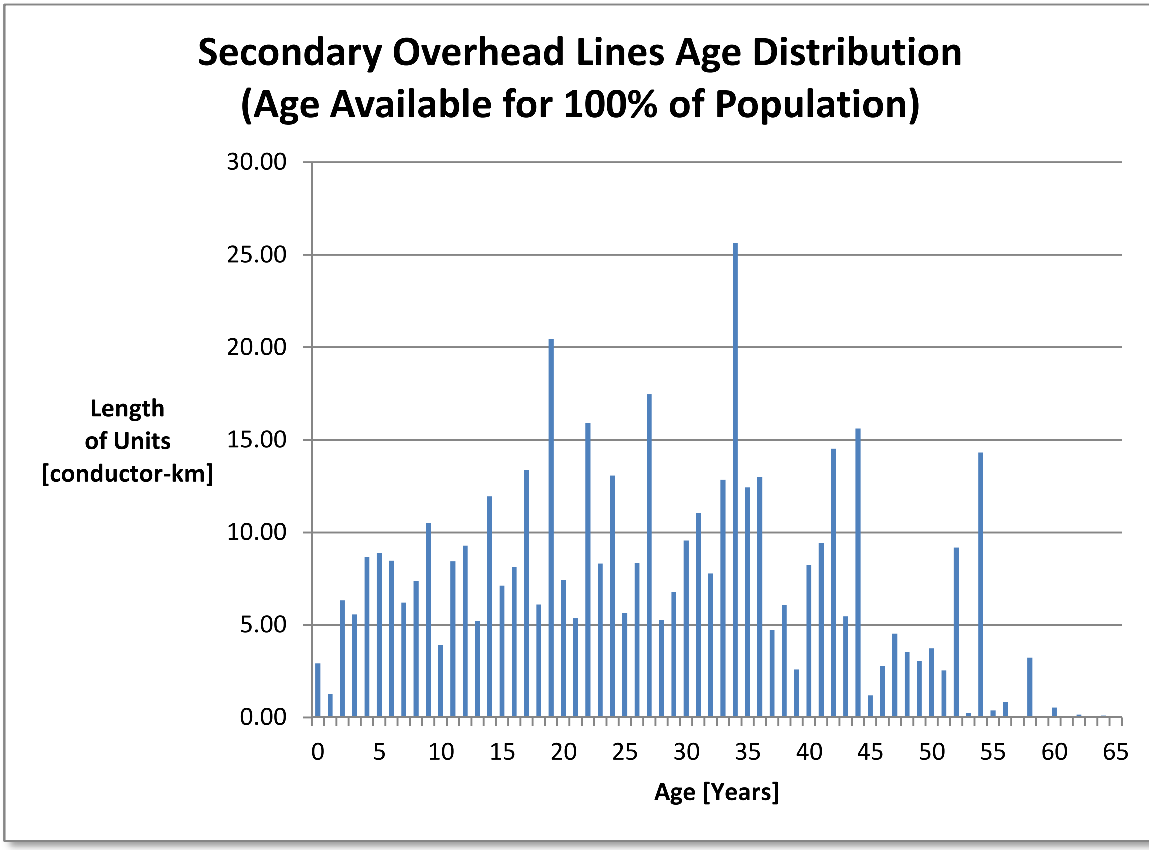


Figure 17-2 Secondary Lines Age Distribution

17.3 Health Index Results

There are 471 conductor-km of in-service Secondary Lines at GHESI. There were 463 conductor-km with sufficient data for Health Indexing.

The average Health Index for this asset group is 97%. None were found to be in poor condition.

The Health Index Results are as follows:

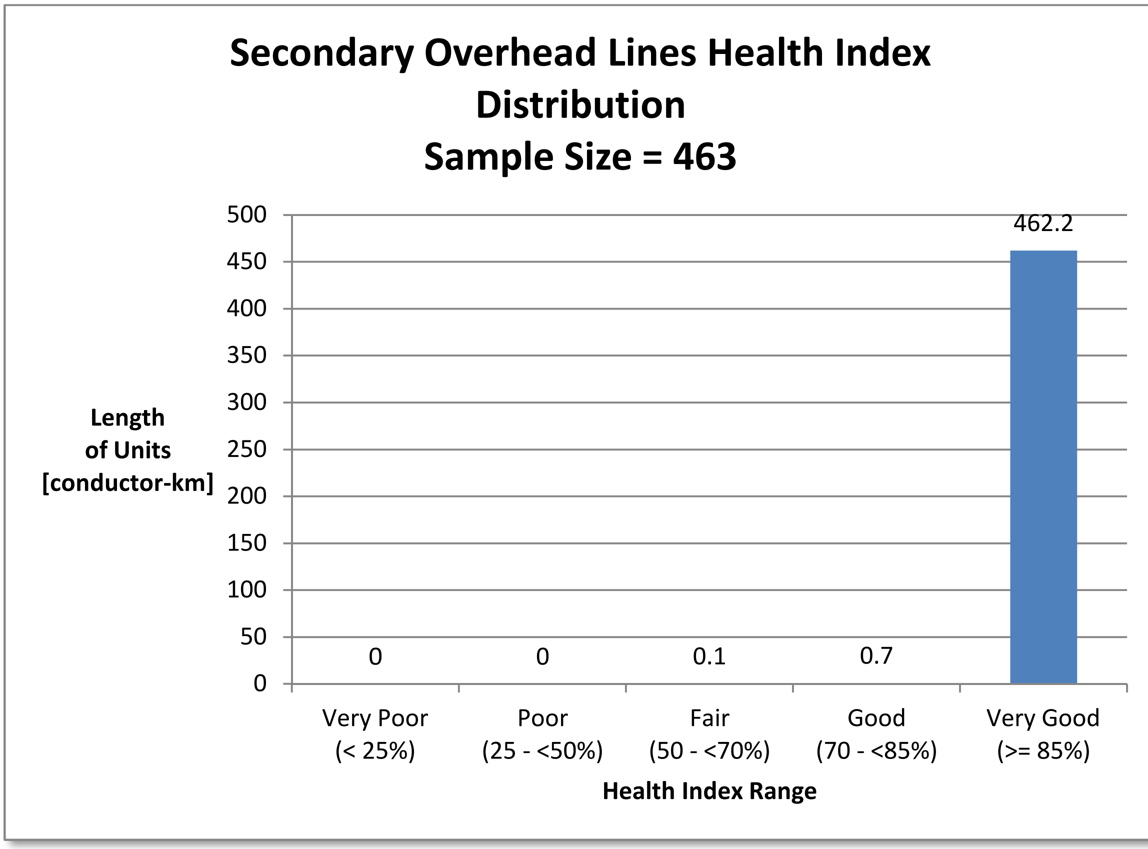


Figure 17-3 Secondary Lines Health Index Distribution (Number of Units)

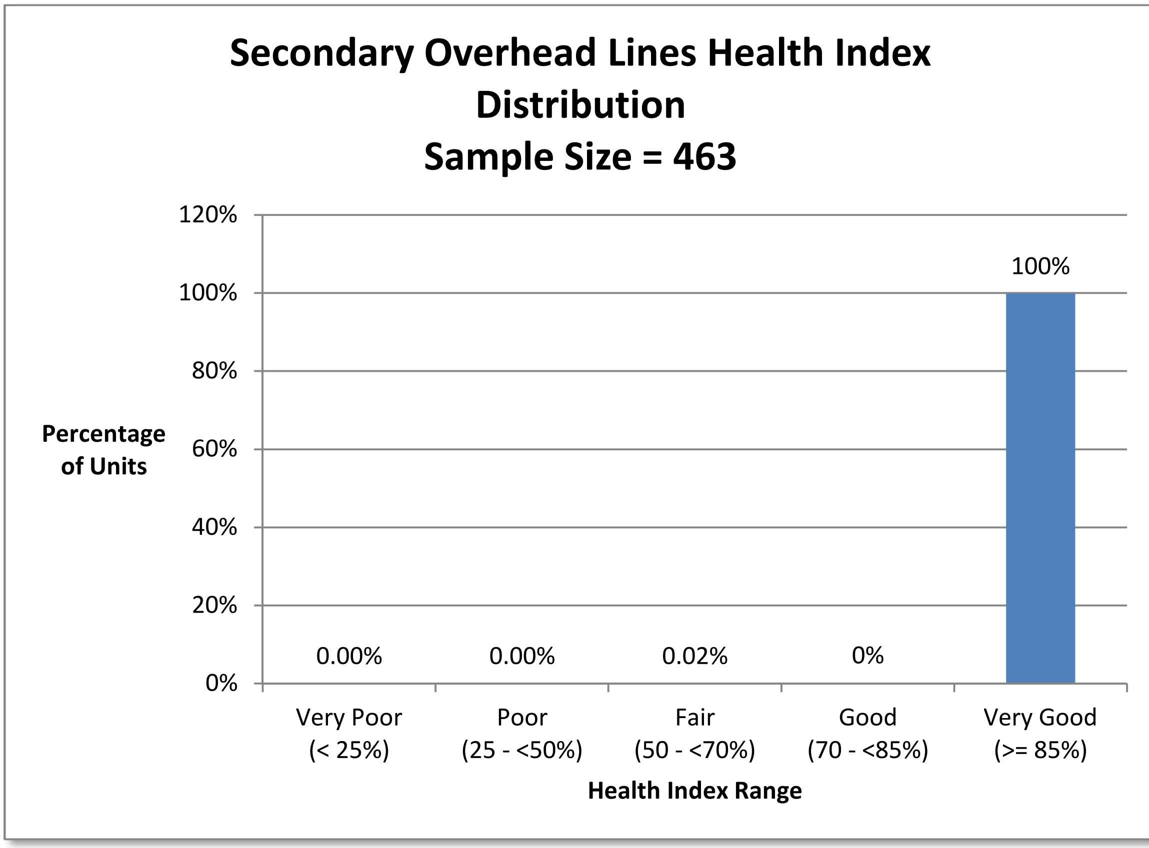


Figure 17-4 Secondary Lines Health Index Distribution (Percentage of Units)

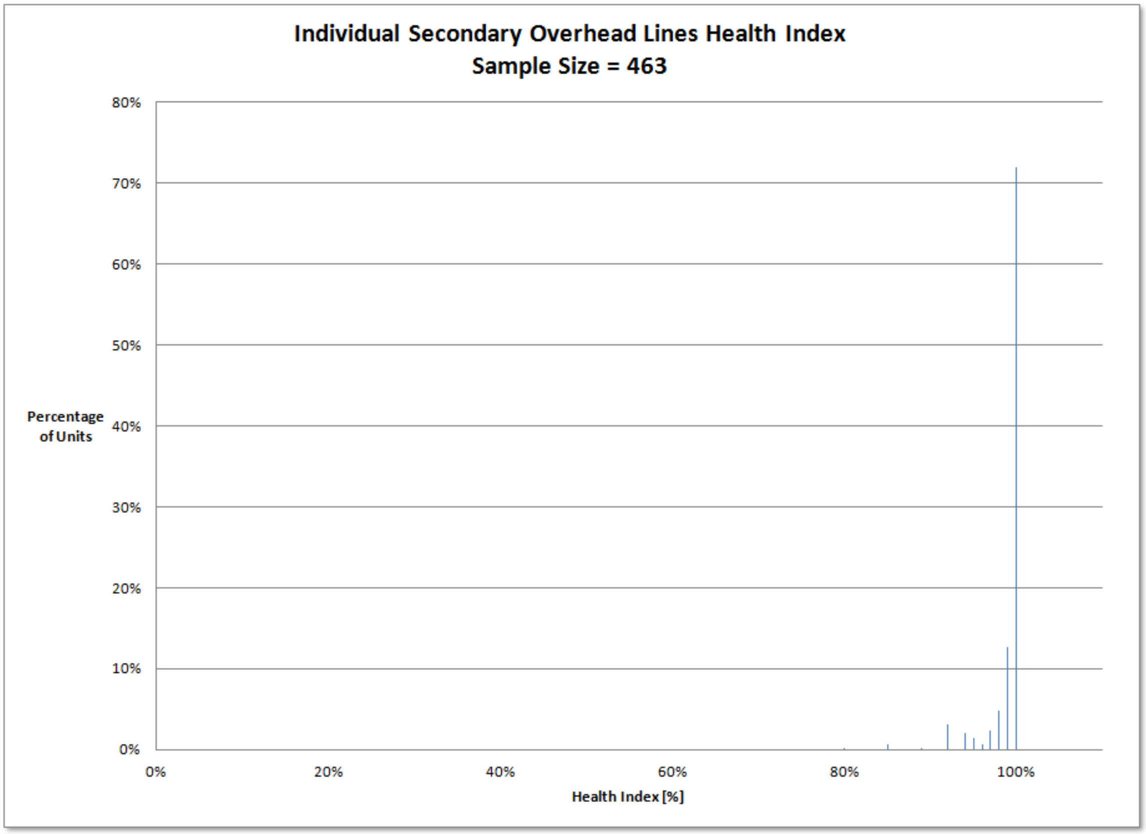


Figure 17-5 Secondary Lines Health Index Distribution by Value (Percentage of Units)

17.4 Condition-Based Flagged for Action Plan

As it is assumed that Secondary Lines are reactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

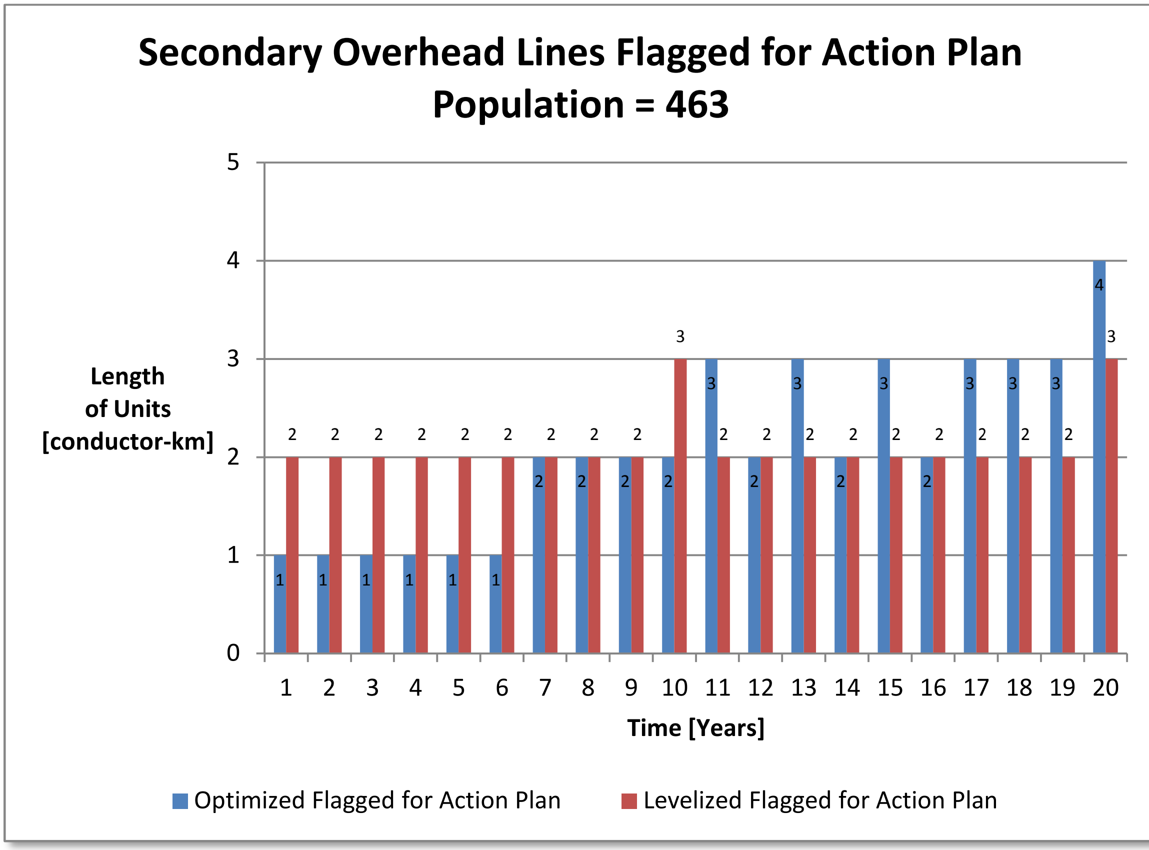


Figure 17-6 Secondary Lines Condition-Based Flagged for Action Plan

17.5 Data Analysis

17.5.1 Data Gap

The data available for Secondary Lines age only. The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Repairs / Splices	Physical Condition	☆☆	Splices or Repairs	Faulty repair or splice	On-site visual inspection
Overall		☆☆	Line Section	Count of total corrective maintenance work orders issued on line section during a specific time window	Operation record

17.5.2 Data Availability Distribution

The average DAI for Secondary Lines is 21%.

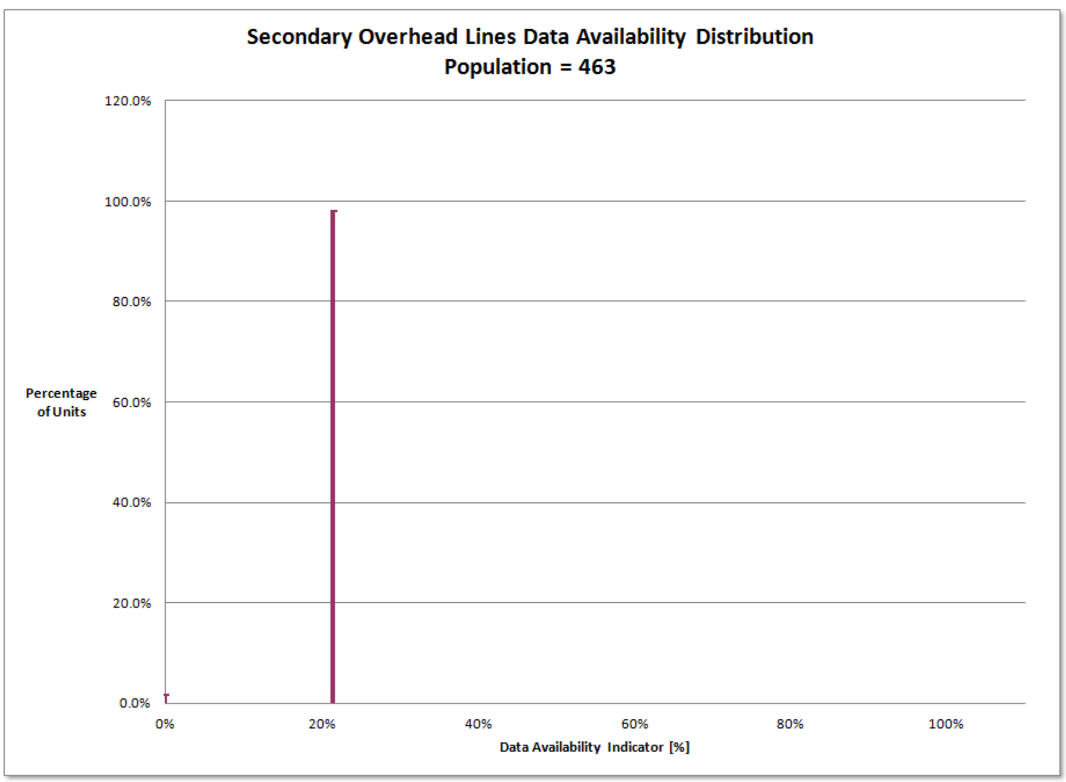


Figure 17-7 Secondary Lines Data Availability Distribution

18 Wood Poles

18.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Wood Poles. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

18.1.1 Condition and Sub-Condition Parameters

Table 18-1 Wood Poles Condition Weights and Maximum CPS

<table>
<tr><th>Condition Parameter</th><th>Condition Parameter Weight</th><th>Sub-Condition Parameter</th><th>Sub-Condition Parameter Weight</th><th>Criteria Lookup Table</th></tr>
<tr><td>Pole Strength</td><td>5</td><td>Pole Strength</td><td>1</td><td>Table 18-2</td></tr>
<tr><td rowspan="8">Physical Condition</td><td rowspan="8">5</td><td>Lean</td><td>1</td><td>Table 18-3</td></tr>
<tr><td>Damage</td><td>2</td><td>Table 18-4</td></tr>
<tr><td>Animal Damage</td><td>2</td><td>Table 18-4
Table 18-5</td></tr>
<tr><td>Surface Rot/Decay</td><td>2</td><td>Table 18-4
Table 18-5</td></tr>
<tr><td>Below Ground Rot/Decay</td><td>3</td><td>Table 18-4</td></tr>
<tr><td>Internal Rot/Decay</td><td>3</td><td>Table 18-4</td></tr>
<tr><td>Holes</td><td>2</td><td>Table 18-4
Table 18-5</td></tr>
<tr><td>Pole Top Feathering</td><td>3</td><td>Table 18-4</td></tr>
<tr><td rowspan="2">Accessories</td><td rowspan="2">1</td><td>Ground</td><td>1</td><td>Table 18-5</td></tr>
<tr><td>Cross Arm</td><td>1</td><td>Table 18-4</td></tr>
<tr><td rowspan="3">Service Record</td><td rowspan="3">4</td><td>Overall Condition</td><td>2</td><td>Table 18-6</td></tr>
<tr><td>Probable Remaining Life</td><td>1</td><td>Table 18-7</td></tr>
<tr><td>Age</td><td>1</td><td>Figure 18-1</td></tr>
<tr><td colspan="2">De-Rating Factor</td><td>Reject Poles, Pole Type</td><td colspan="2">Table 18-8</td></tr>
</table>

18.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Wood Poles 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 50 and 60 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

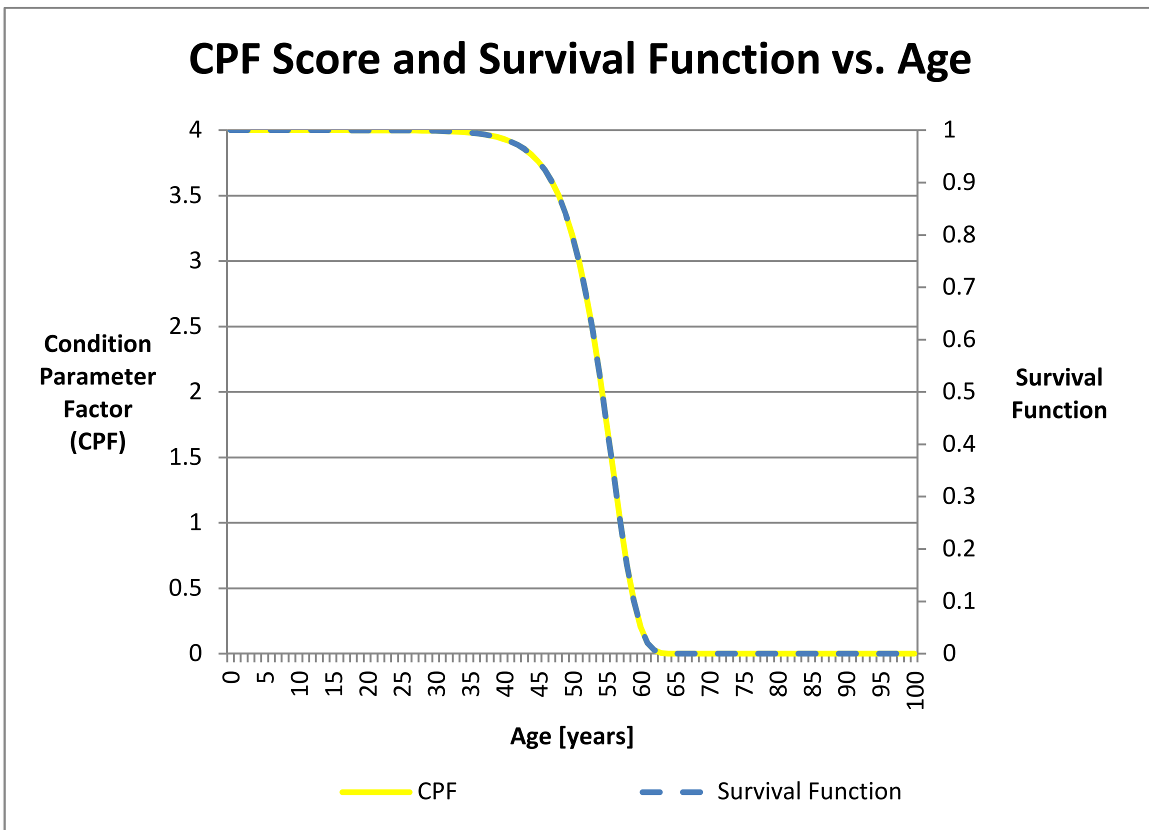


Figure 18-1 Wood Poles Age Condition Criteria

Pole Strength

Table 18-2 Wood Poles Strength Description and Score

Percentage of Maximum Strength (Measured PSI/Maximum PSI)	Score
< 50%	0
50 - 66%	1
67 - 79%	2
80 - 89%	3
90%	4

Where Maximum PSI is:

Type	Maximum Strength (PSI)
Douglas Fir	8000
Jack Pine	6600
Lodge Pine	6600
Pine	6600
Red Pine	6600
Southern Pine	6600
Western Red Cedar	6000

Lean

Table 18-3 Wood Poles Leaning Description and Score

Pole Leaning	Score
Yes	0
No	4

Inspection Results

Table 18-4 Wood Poles Inspection Description and Score

Status	Score
None	4
Slight/Mild	3
Medium/Moderate	2
Severe/Extensive	0

Okay/Not Okay

Table 18-5 Wood Poles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Overall Condition

Table 18-6 Wood Poles Overall Condition Description and Score

Status	Score
Poor	0
Fair-Poor	1
Fair	2
Good	4

Probable Remaining Life

Table 18-7 Wood Poles Remaining Life Description and Score

Estimated Remaining Life (Years)	Score
< 0	0
0 - 10	1
10 - 20	3
20 +	4

De-Rating Factor

The final De-Rating factor (DRF) is calculated as follows:

$$DRF = \min(DRF1, DRF2)$$

where

Table 18-8 Wood Poles De-Rating Factor Description and Value

De-Rating Factor	Description	De-Rating Value
DRF1	Reject Pole	25%
DRF2	Pole Type Douglas Fir	80%

18.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 88% of the population. The average age was found to be 34 years.

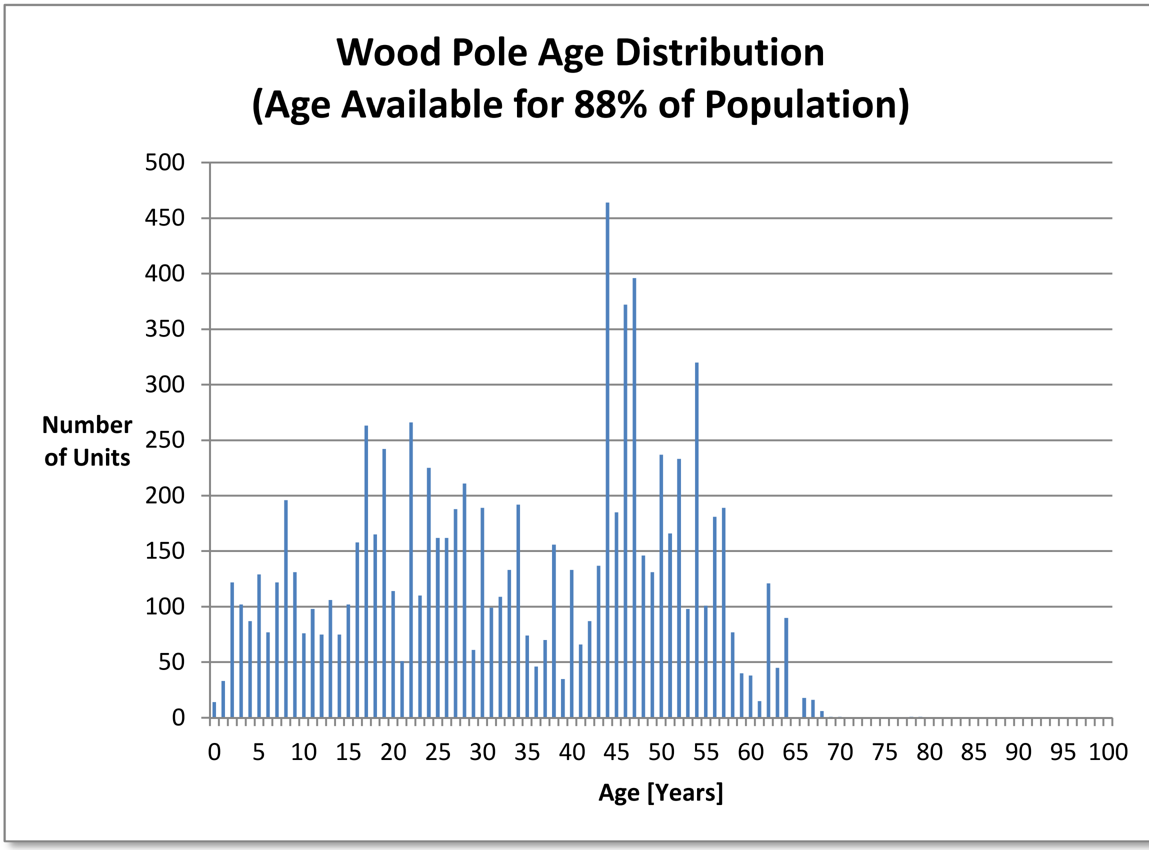


Figure 18-2 Wood Poles Age Distribution

18.3 Health Index Results

There are 10426 in-service Wood Poles at GHESI. There were 10426 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 80%. Approximately 4% of the units were found to be in poor condition.

The Health Index Results are as follows:

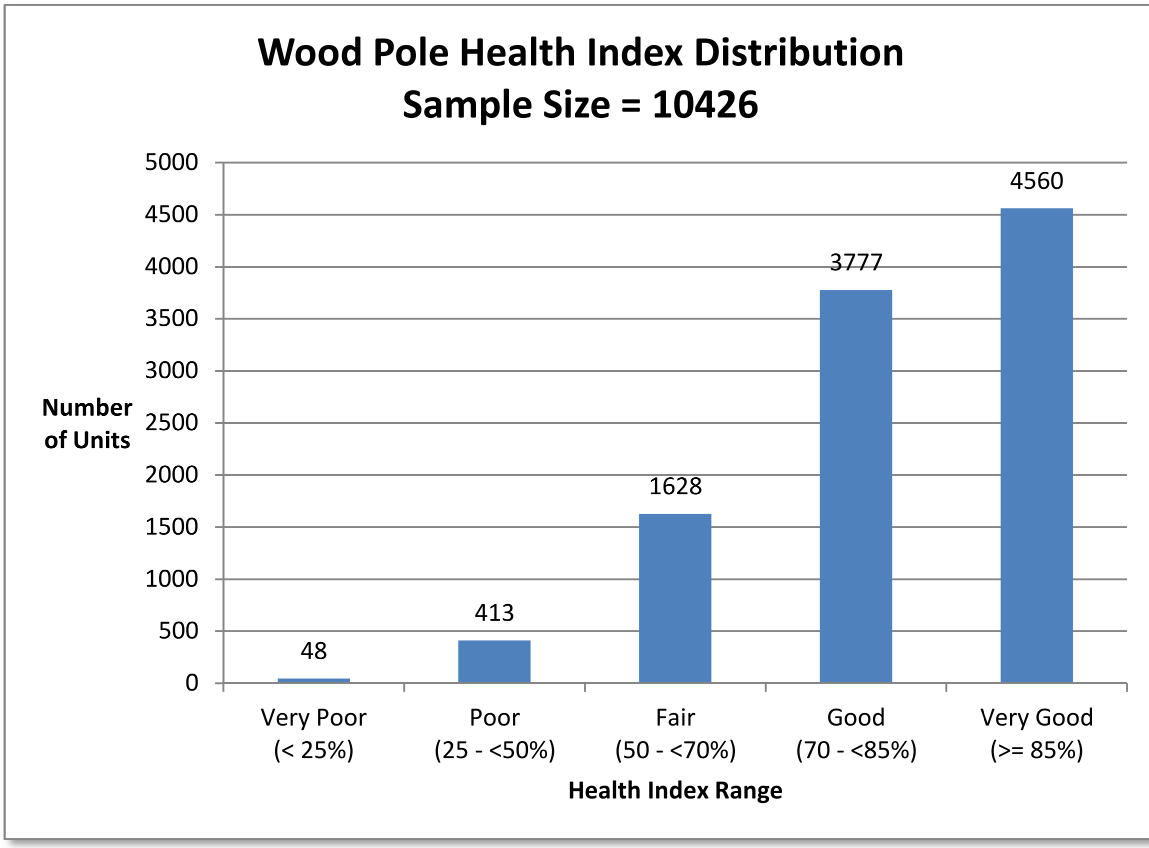


Figure 18-3 Wood Poles Health Index Distribution (Number of Units)

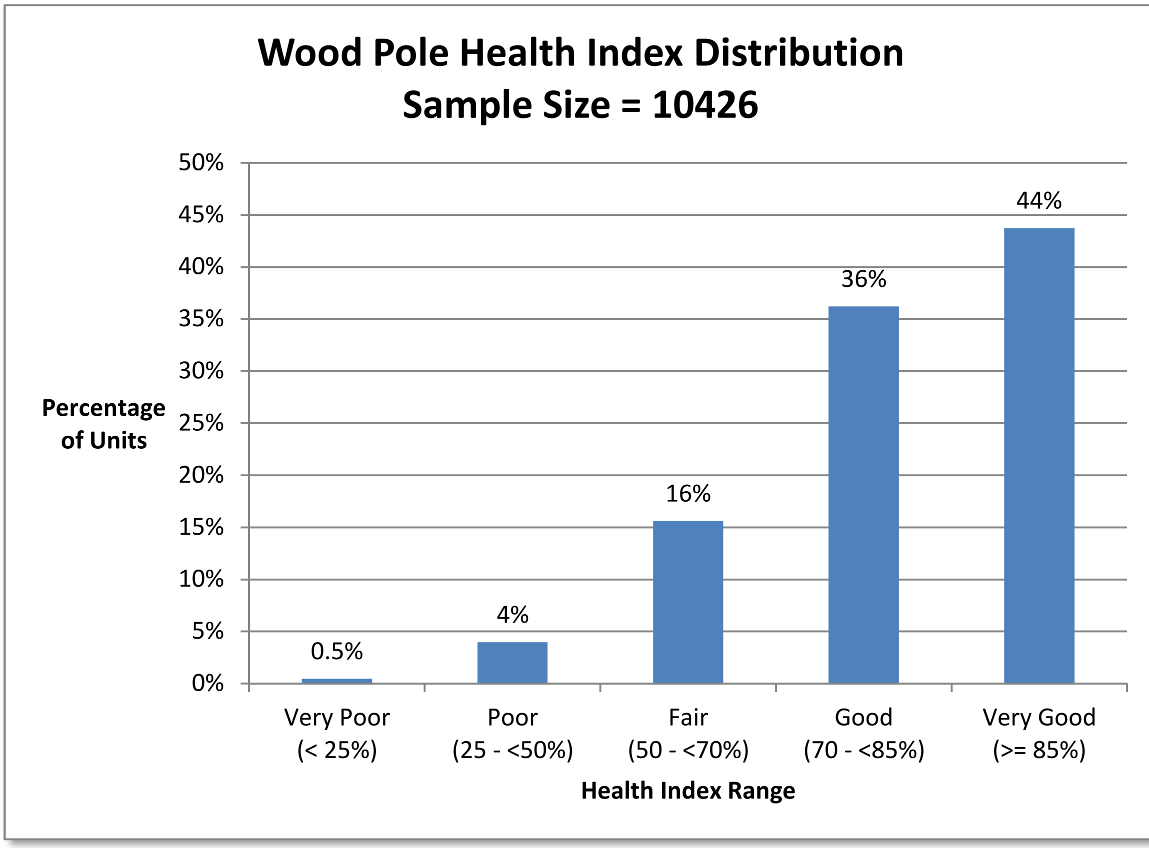


Figure 18-4 Wood Poles Health Index Distribution (Percentage of Units)

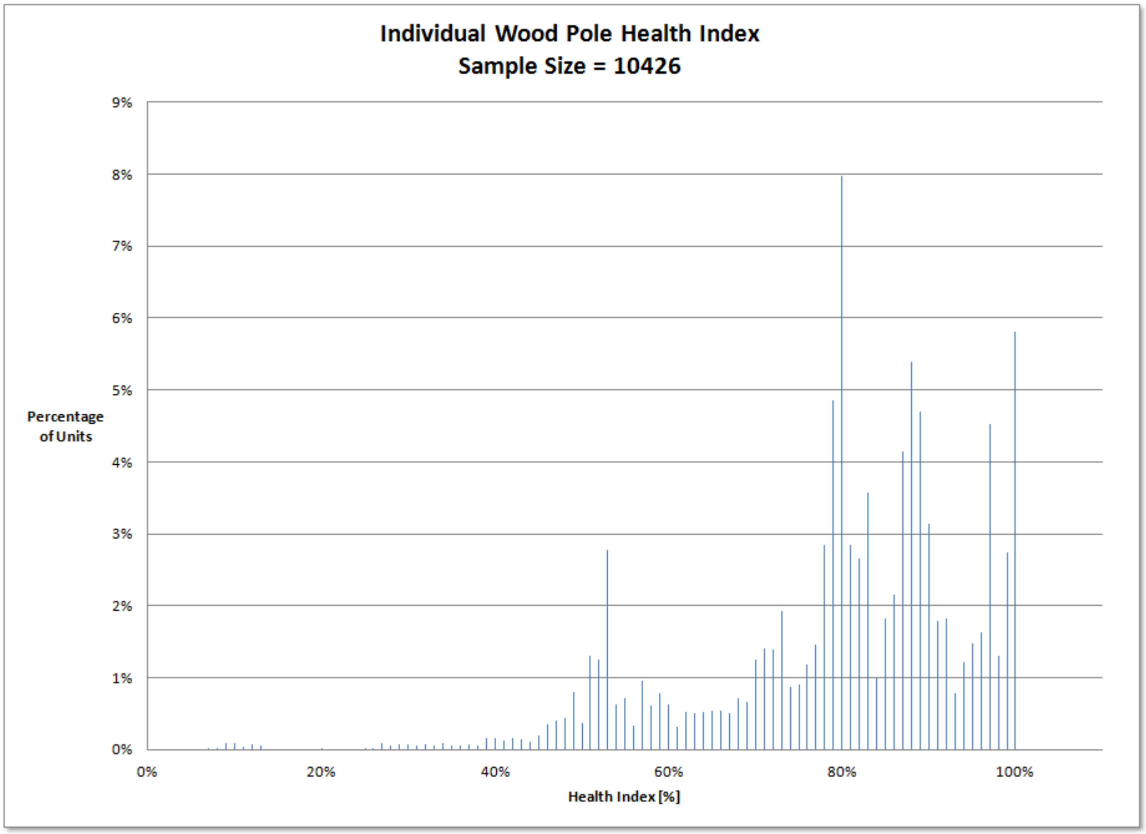


Figure 18-5 Wood Poles Health Index Distribution by Value (Percentage of Units)

18.4 Condition-Based Flagged for Action Plan

Although Wood Poles are proactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

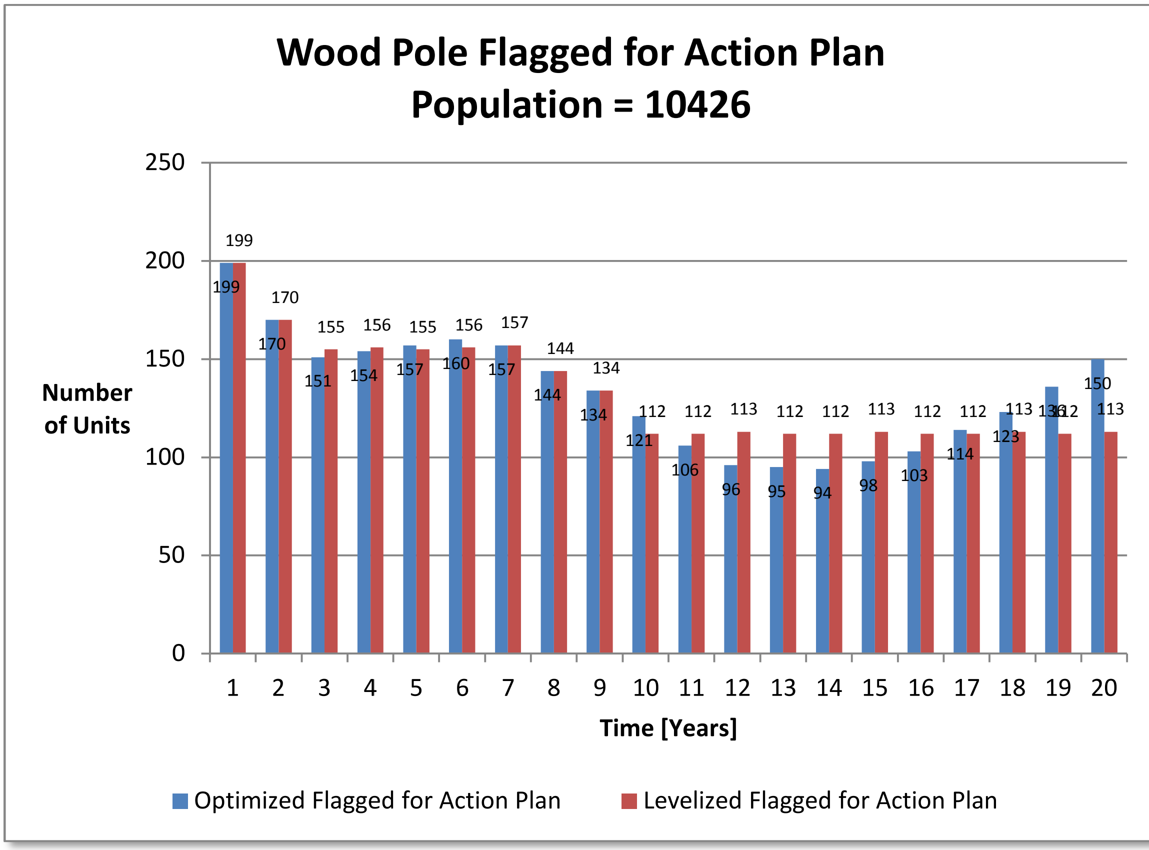


Figure 18-6 Wood Poles Condition-Based Flagged for Action Plan

18.5 Data Analysis

18.5.1 Data Gap

The data available for Wood Poles are age, pole strength, and inspection records. There are no data gaps identified.

18.5.2 Data Availability Distribution

The average DAI for Wood Poles is 86%.

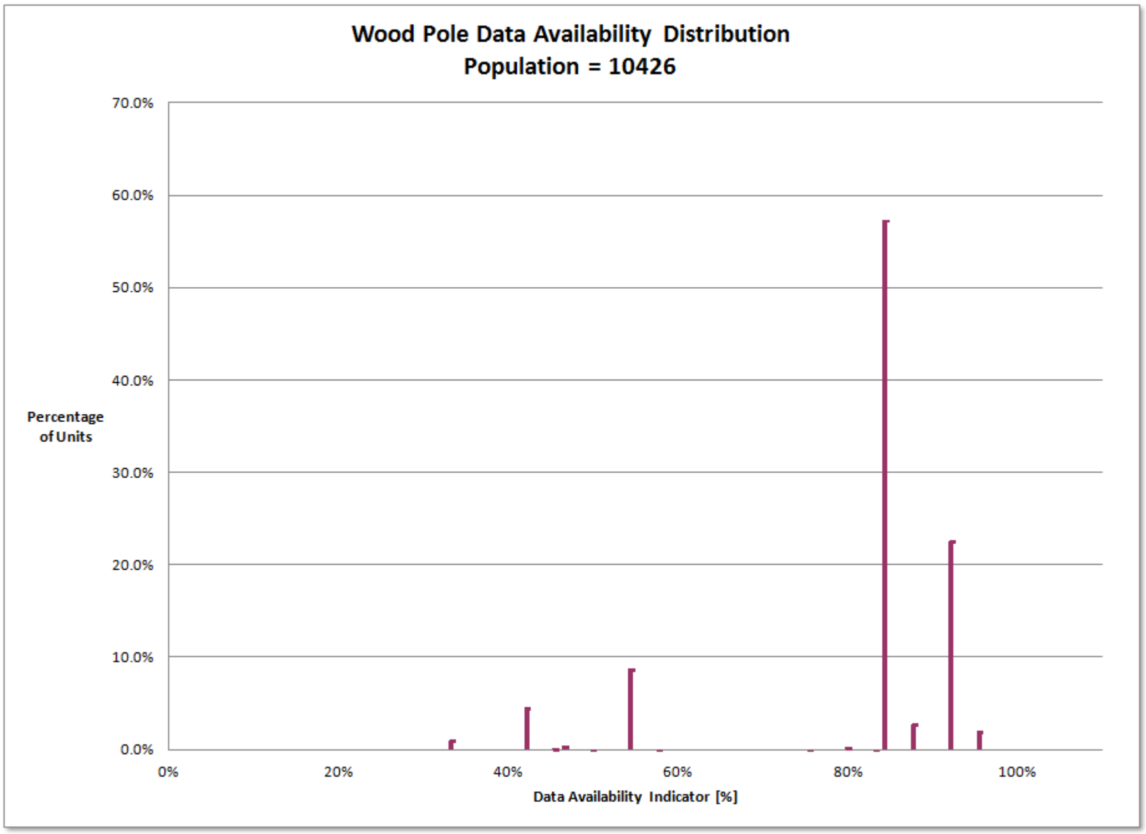


Figure 18-7 Wood Poles Data Availability Distribution

19 Concrete Poles

19.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Concrete Poles. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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”.

19.1.1 Condition and Sub-Condition Parameters

Table 19-1 Concrete Poles Condition Weights and Maximum CPS

<table>
<tr><th>Condition Parameter</th><th>Condition Parameter Weight</th><th>Sub-Condition Parameter</th><th>Sub-Condition Parameter Weight</th><th>Criteria Lookup Table</th></tr>
<tr><td rowspan="4">Physical Condition</td><td rowspan="4">5</td><td>Lean</td><td>2</td><td>Table 19-2</td></tr>
<tr><td>Damage</td><td>3</td><td>Table 19-3</td></tr>
<tr><td>Surface Damage</td><td>3</td><td>Table 19-3</td></tr>
<tr><td>Below Ground Damage</td><td>4</td><td>Table 19-3</td></tr>
<tr><td rowspan="2">Accessories</td><td rowspan="2">1</td><td>Ground</td><td>1</td><td>Table 19-4</td></tr>
<tr><td>Cross Arm</td><td>1</td><td>Table 19-4</td></tr>
<tr><td rowspan="2">Service Record</td><td rowspan="2">4</td><td>Overall Condition</td><td>2</td><td>Table 19-5</td></tr>
<tr><td>Age</td><td>1</td><td>Figure 20-1</td></tr>
<tr><td colspan="2">De-Rating Factor</td><td>Reject Pole, Arterial Pole</td><td colspan="2">Table 19-6</td></tr>
</table>

19.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Concrete Poles 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 50 and 60 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

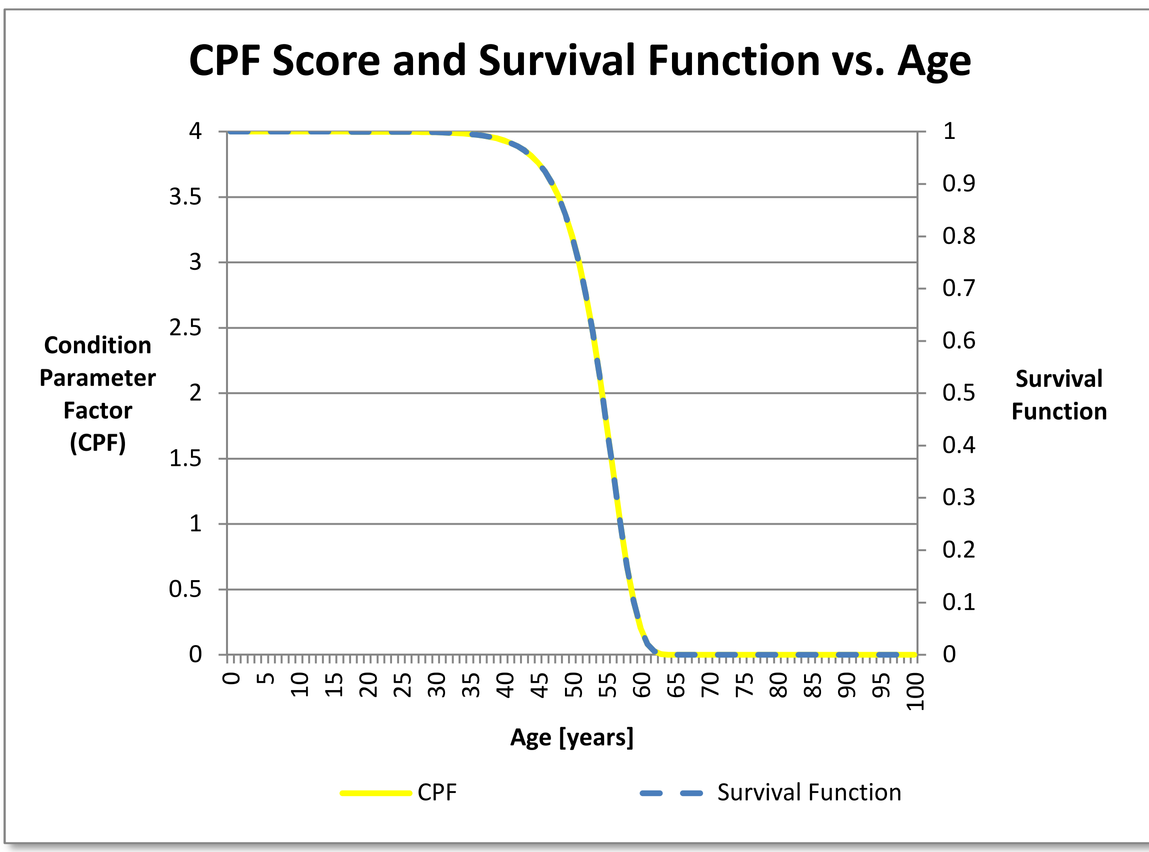


Figure 19-1 Concrete Poles Age Condition Criteria

Lean

Table 19-2 Concrete Poles Leaning Description and Score

Pole Leaning	Score
Yes	0
No	4

Inspection Results

Table 19-3 Concrete Poles Inspection Description and Score

Status	Score
None	4
Slight/Mild	3
Medium/Moderate	2
Severe/Extensive	0

Okay/Not Okay

Table 19-4 Concrete Poles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Overall Condition

Table 19-5 Concrete Poles Overall Condition Description and Score

Status	Score
Poor	0
Fair-Poor	1
Fair	2
Good	4

De-Rating Factor

The final De-Rating factor (DRF) is calculated as follows:

$$DRF = \min(DRF1, DRF2)$$

where

Table 19-6 Concrete Poles De-Rating Factor Description and Value

De-Rating Factor	Description	De-Rating Value
DRF1	Reject Pole	25%
DRF2	Arterial Pole	85%

19.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 16 years.

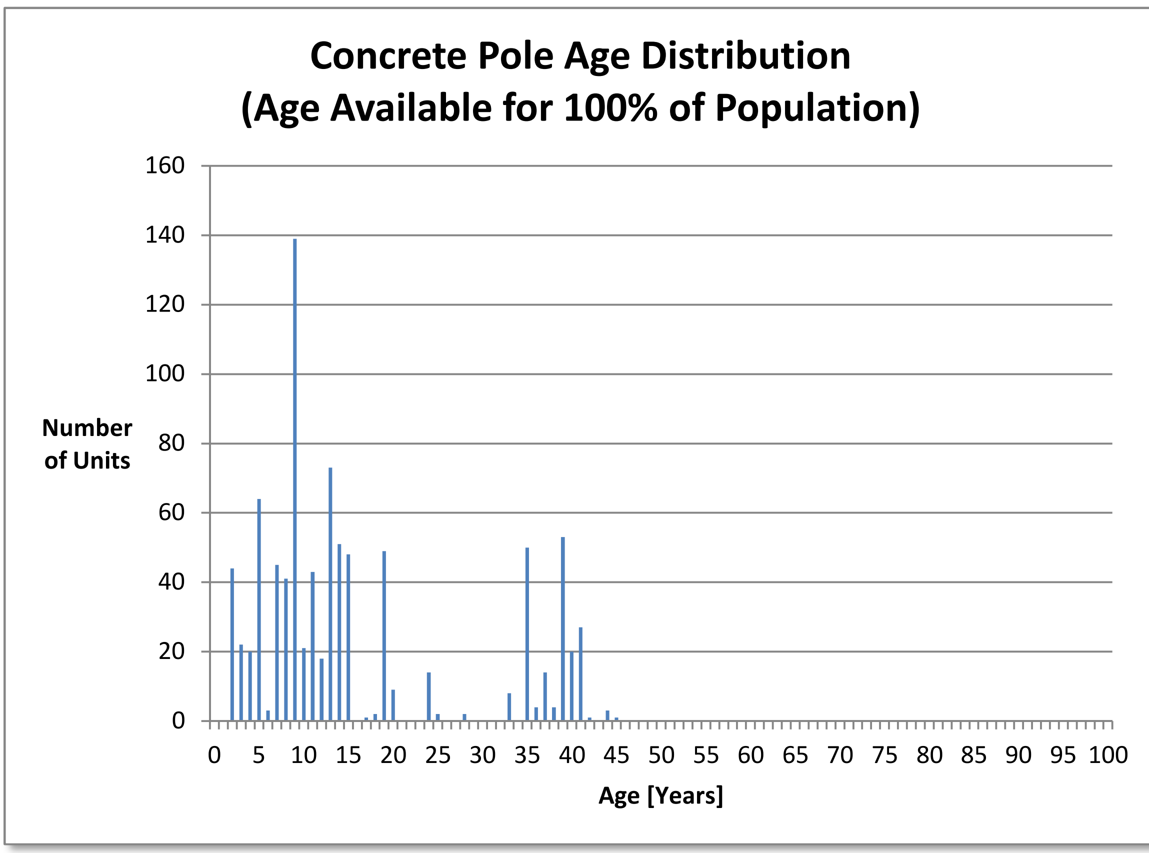


Figure 19-2 Concrete Poles Age Distribution

19.3 Health Index Results

There are 897 in-service Concrete Poles at GHESI. There were 896 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 96%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

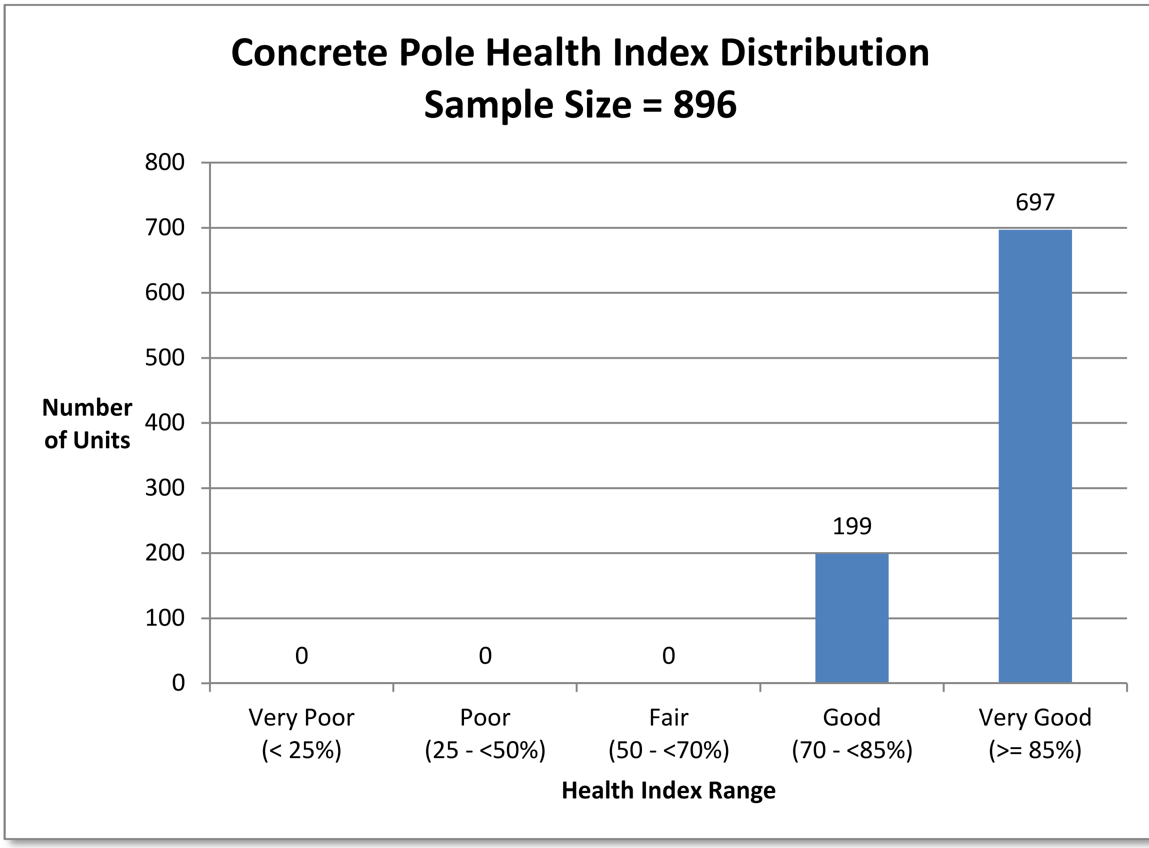


Figure 19-3 Concrete Poles Health Index Distribution (Number of Units)

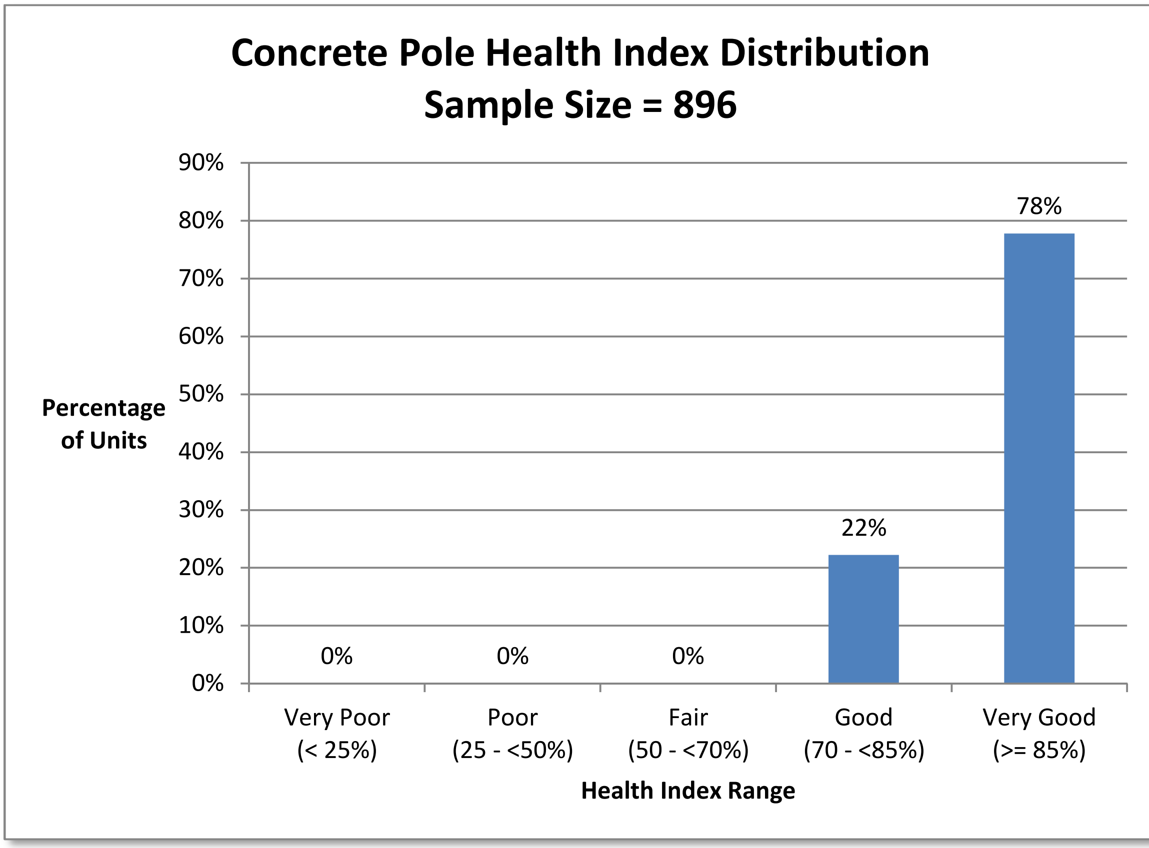


Figure 19-4 Concrete Poles Health Index Distribution (Percentage of Units)

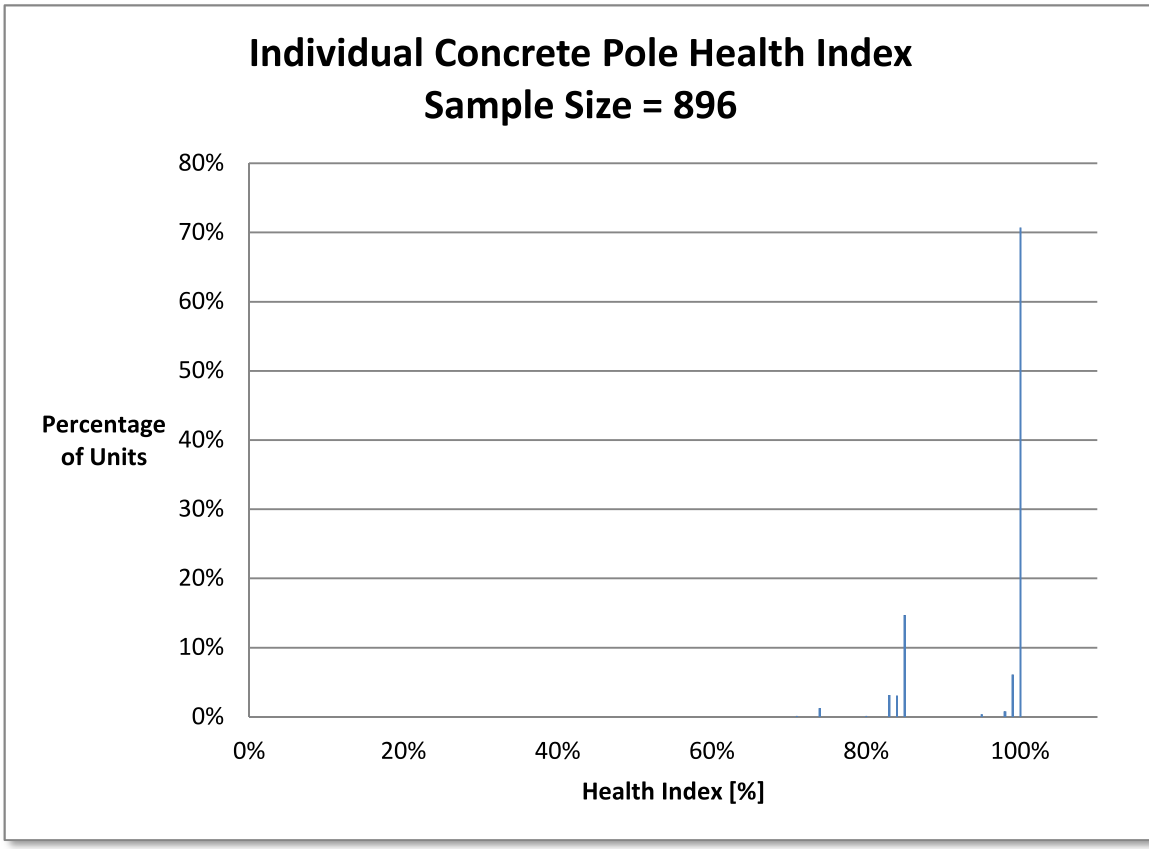


Figure 19-5 Concrete Poles Health Index Distribution by Value (Percentage of Units)

19.4 Condition-Based Flagged for Action Plan

Although Concrete Poles are proactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

In the next 20 years no units are expected to be flagged for action.

19.5 Data Analysis

19.5.1 Data Gap

The data available for Concrete Poles are age and inspection records. No data gaps are identified.

19.5.2 Data Availability Distribution

Because only about 10% of concrete poles have inspection records, the average DAI for Concrete Poles is 10%.

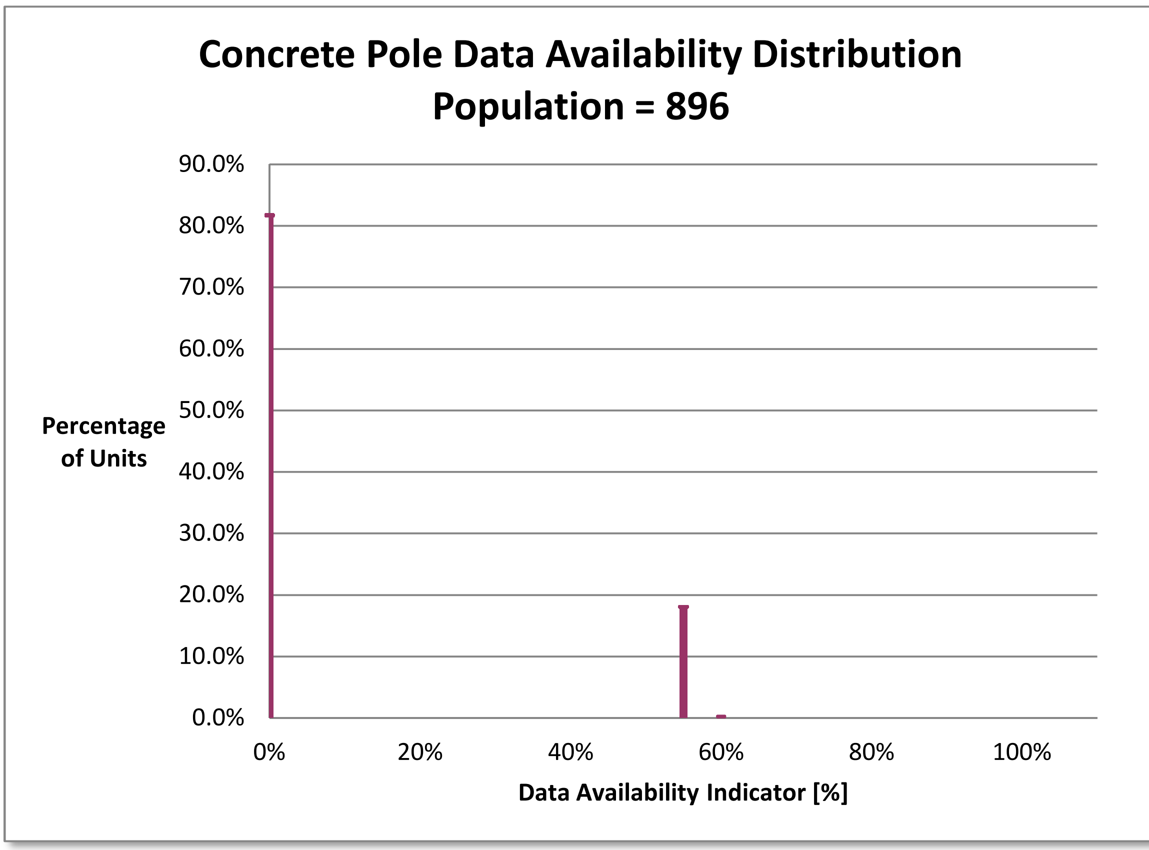


Figure 19-6 Concrete Poles Data Availability Distribution

20 Composite Poles

20.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Composite Poles. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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".

20.1.1 Condition and Sub-Condition Parameters

Table 20-1 Composite Poles Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight	Criteria Lookup Table
Physical Condition	5	Lean	2	Table 20-2
		Damage	3	Table 20-3
		Surface Damage	3	Table 20-3
		Below Ground Damage	4	Table 20-3
Accessories	1	Ground	1	Table 20-4
		Cross Arm	1	Table 20-4
Service Record	4	Overall Condition	2	Table 20-5
		Age	1	Figure 20-1
De-Rating Factor		Reject Pole	25%	

20.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Composite Poles 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 50 and 100 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

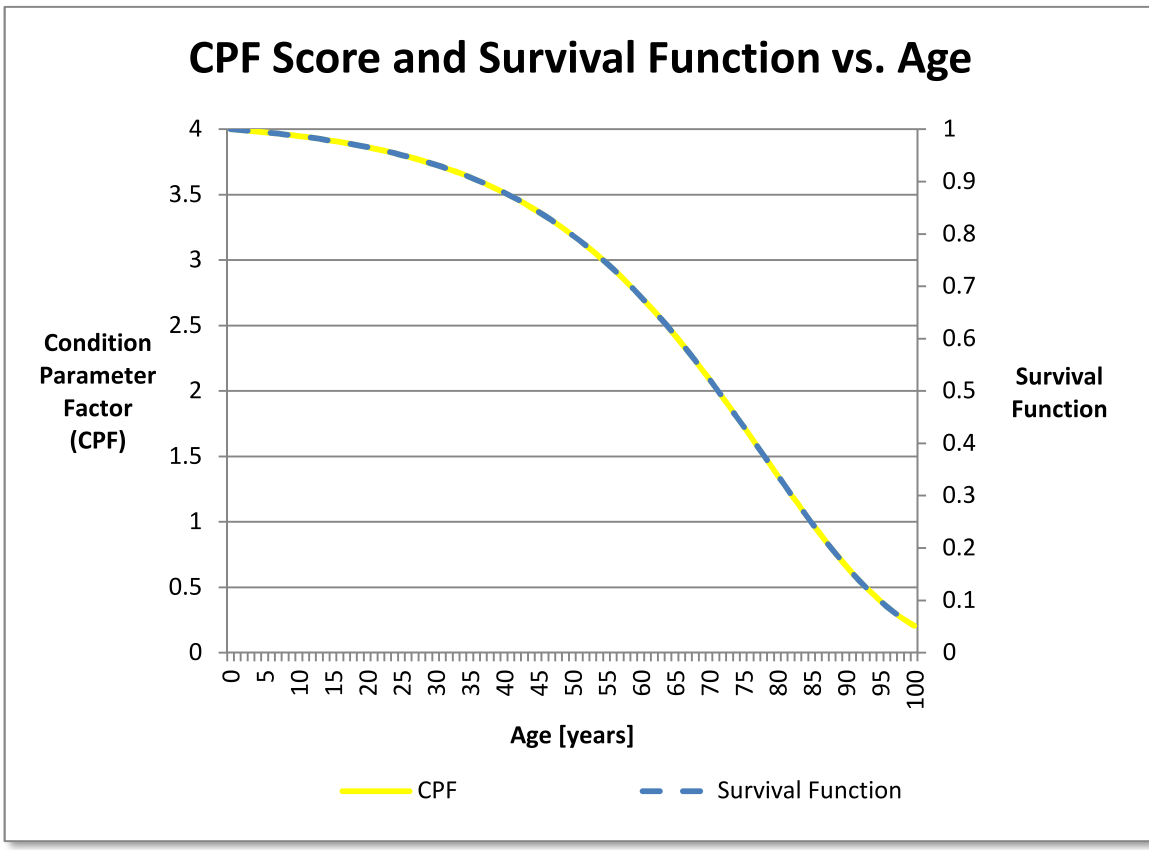


Figure 20-1 Composite Poles Age Condition Criteria

Lean

Table 20-2 Composite Poles Leaning Description and Score

Pole Leaning	Score
Yes	0
No	4

Inspection Results

Table 20-3 Composite Poles Inspection Description and Score

Status	Score
None	4
Slight/Mild	3
Medium/Moderate	2
Severe/Extensive	0

Okay/Not Okay

Table 20-4 Composite Poles Okay/Not Okay Description and Score

Problem Found	Score
TRUE	0
FALSE	4

Overall Condition

Table 20-5 Composite Poles Overall Condition Description and Score

Status	Score
Poor	0
Fair-Poor	1
Fair	2
Good	4

20.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 99% of the population. The average age was found to be 4 years.

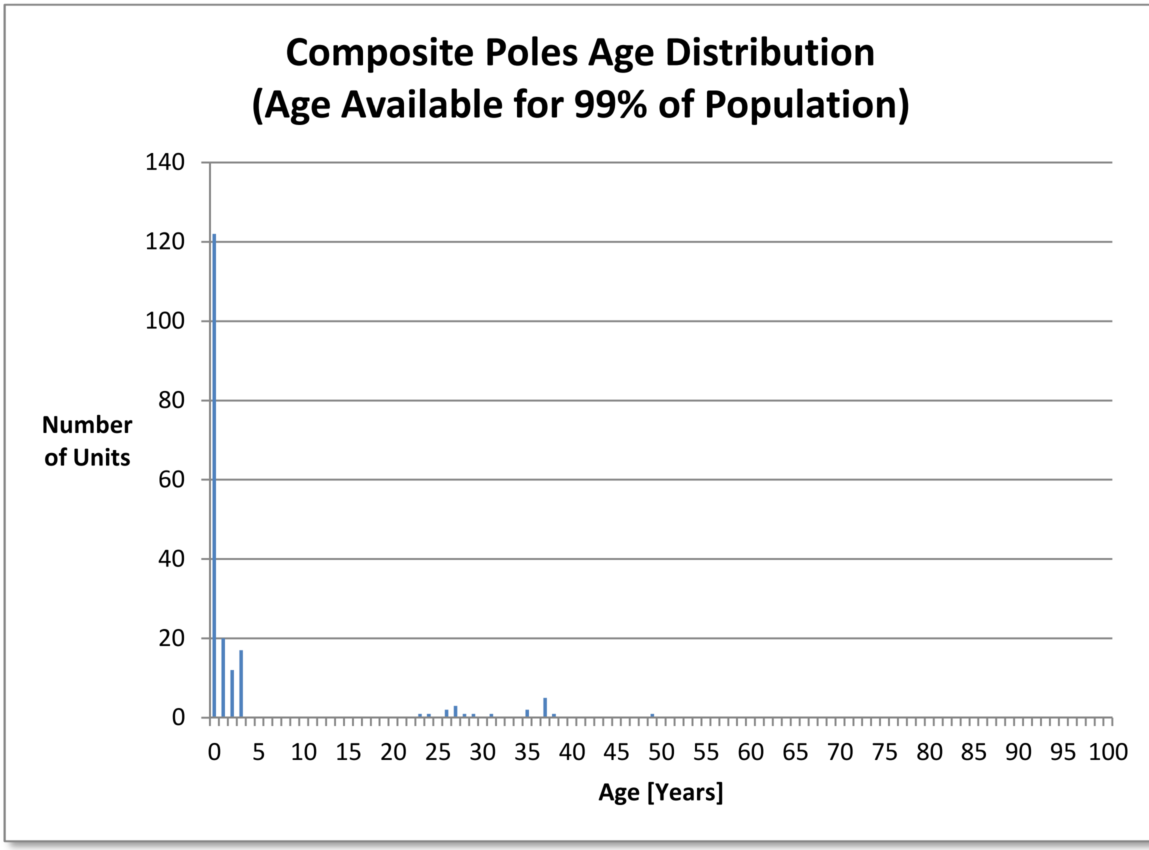


Figure 20-2 Composite Poles Age Distribution

20.3 Health Index Results

There are 191 in-service Composite Poles at GHESI. There were 190 units with sufficient data for Health Indexing.

The average Health Index for this asset group is 99%. None of the units were found to be in poor condition.

The Health Index Results are as follows:

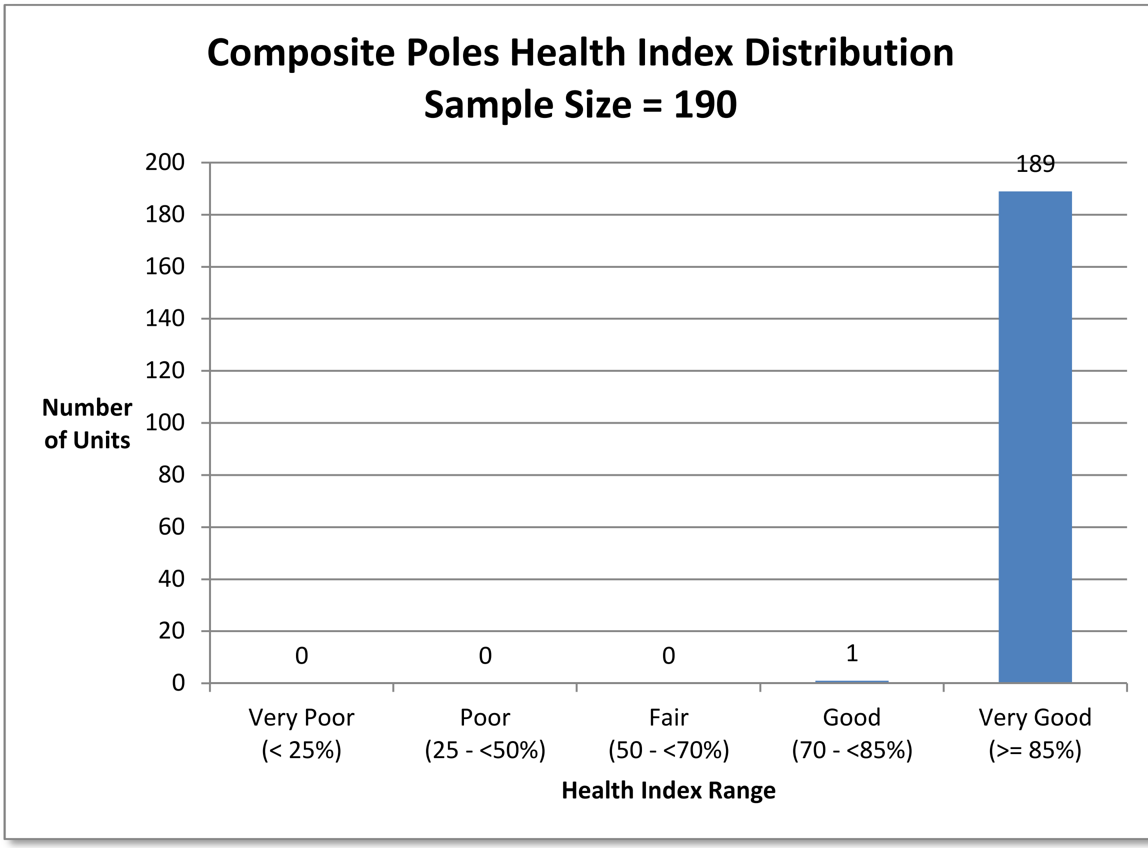


Figure 20-3 Composite Poles Health Index Distribution (Number of Units)

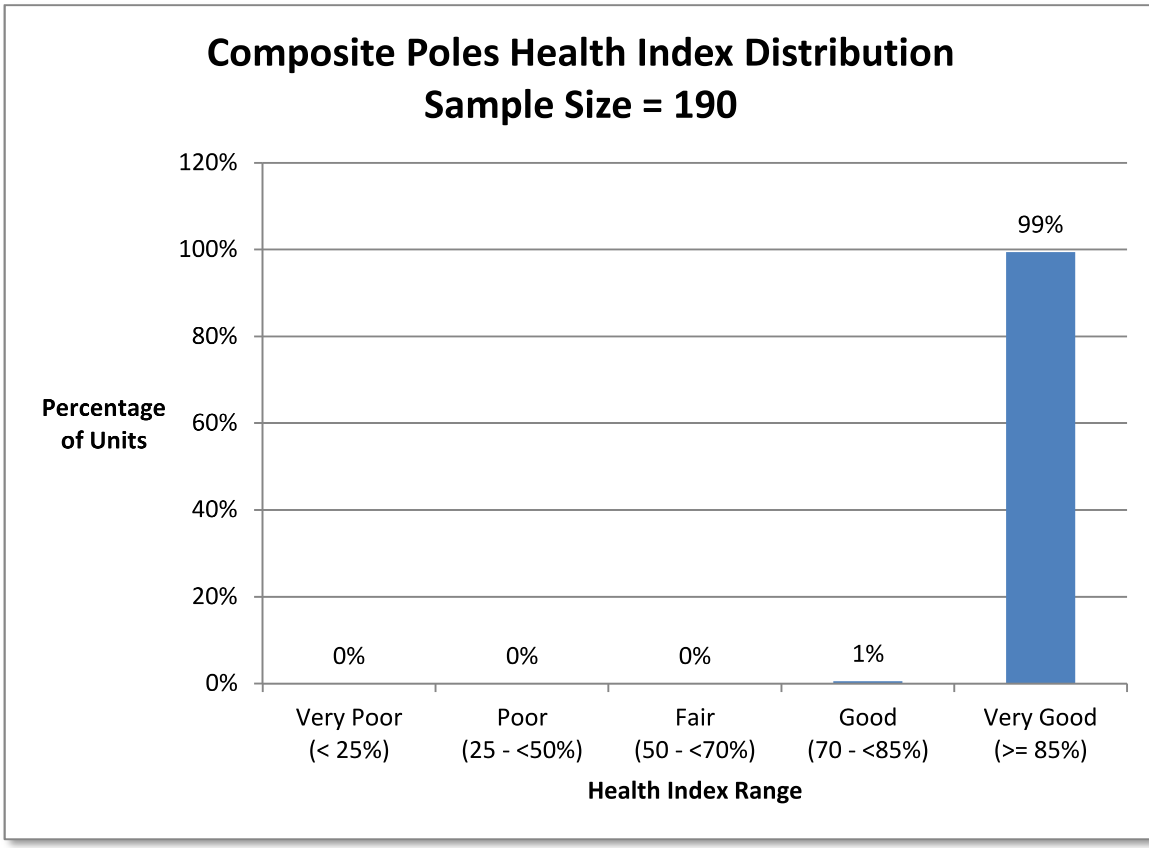


Figure 20-4 Composite Poles Health Index Distribution (Percentage of Units)

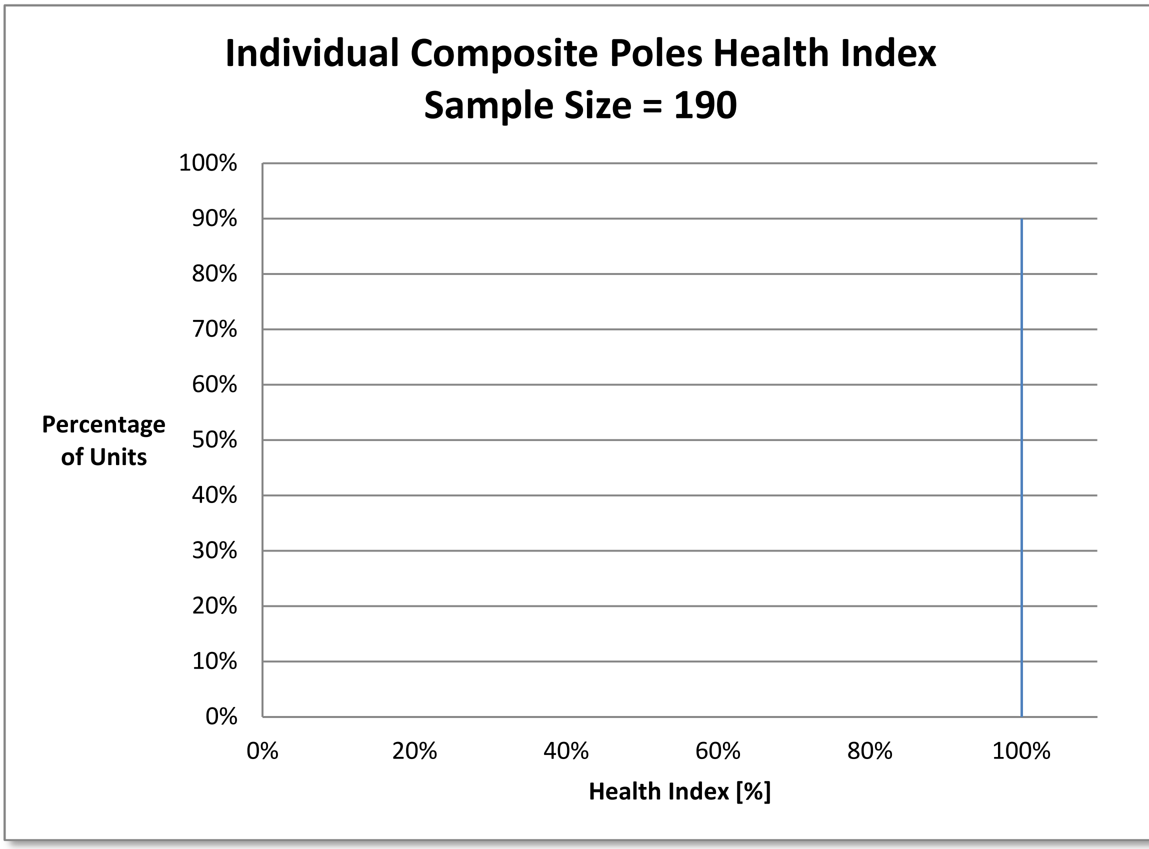


Figure 20-5 Composite Poles Health Index Distribution by Value (Percentage of Units)

20.4 Condition-Based Flagged for Action Plan

Although Composite Poles are proactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

In the next 20 years no units are expected to be flagged for action.

20.5 Data Analysis

20.5.1 Data Gap

The data available for Composite Poles are age and inspection records. It should be noted that inspections are available only for 5% of the population. No data gaps are identified.

20.5.2 Data Availability Distribution

The average DAI for Composite Poles is 3%.

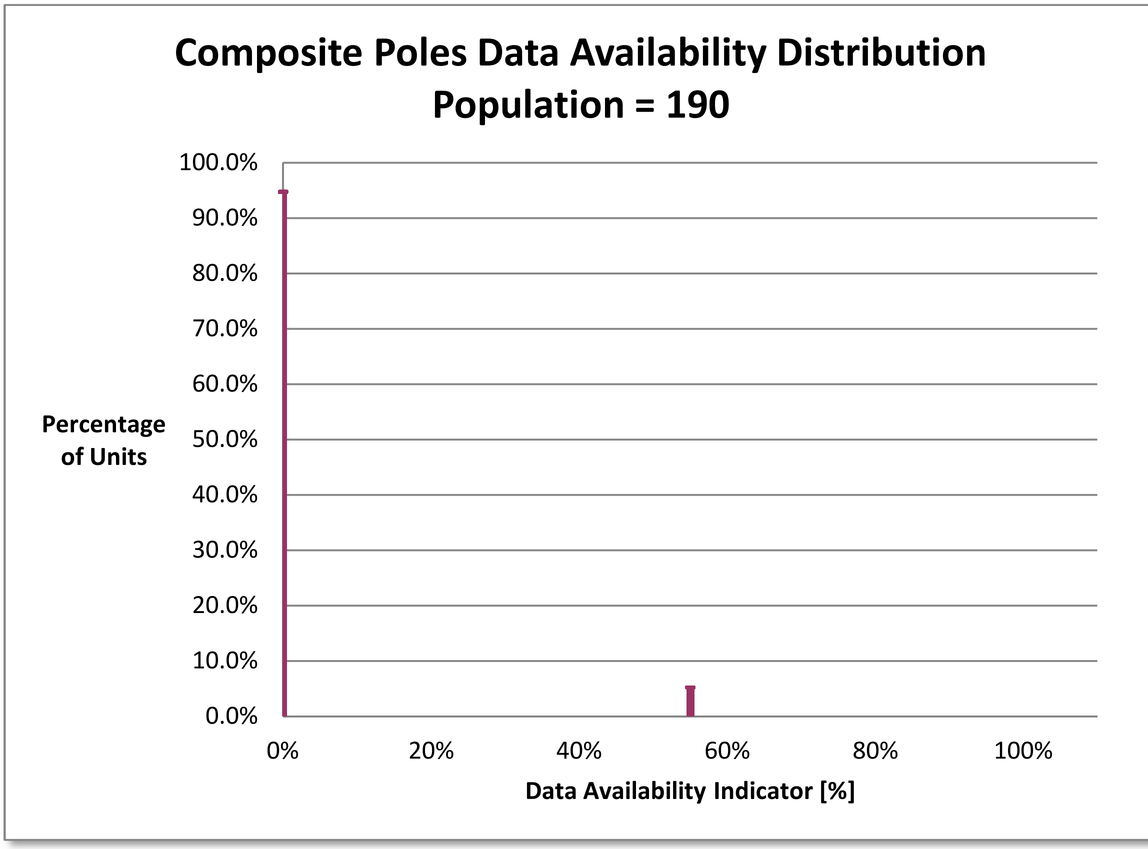


Figure 20-6 Composite Poles Data Availability Distribution

21 Vaults

21.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Vaults. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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”.

21.1.1 Condition and Sub-Condition Parameters

Table 21-1 Vaults Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight			Criteria Lookup Table
Walls	6	North Wall	1	Cracks	8	Table 21-2
				Spalling	5	Table 21-2
				Corrosion	5	Table 21-2
		South Wall	1	Cracks	8	Table 21-2
				Spalling	5	Table 21-2
				Corrosion	5	Table 21-2
		East Wall	1	Cracks	8	Table 21-2
				Spalling	5	Table 21-2
				Corrosion	5	Table 21-2
		West Wall	1	Cracks	8	Table 21-2
				Spalling	5	Table 21-2
				Corrosion	5	Table 21-2
Floor	1	Cracks	8			Table 21-2
		Spalling	5			Table 21-2
		Corrosion	5			Table 21-2
Ceiling	10	Cracks	8			Table 21-2
		Spalling	5			Table 21-2
		Corrosion	5			Table 21-2
De-Rating Factor		Ceiling	If MIN(cracks, spalling, corrosion) = 0 de-rate 75% If MIN(cracks, spalling, corrosion) = 1 de-rate 50% If MIN(cracks, spalling, corrosion) = 2 de-rate 15%			

21.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Vaults 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 50 and 80 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

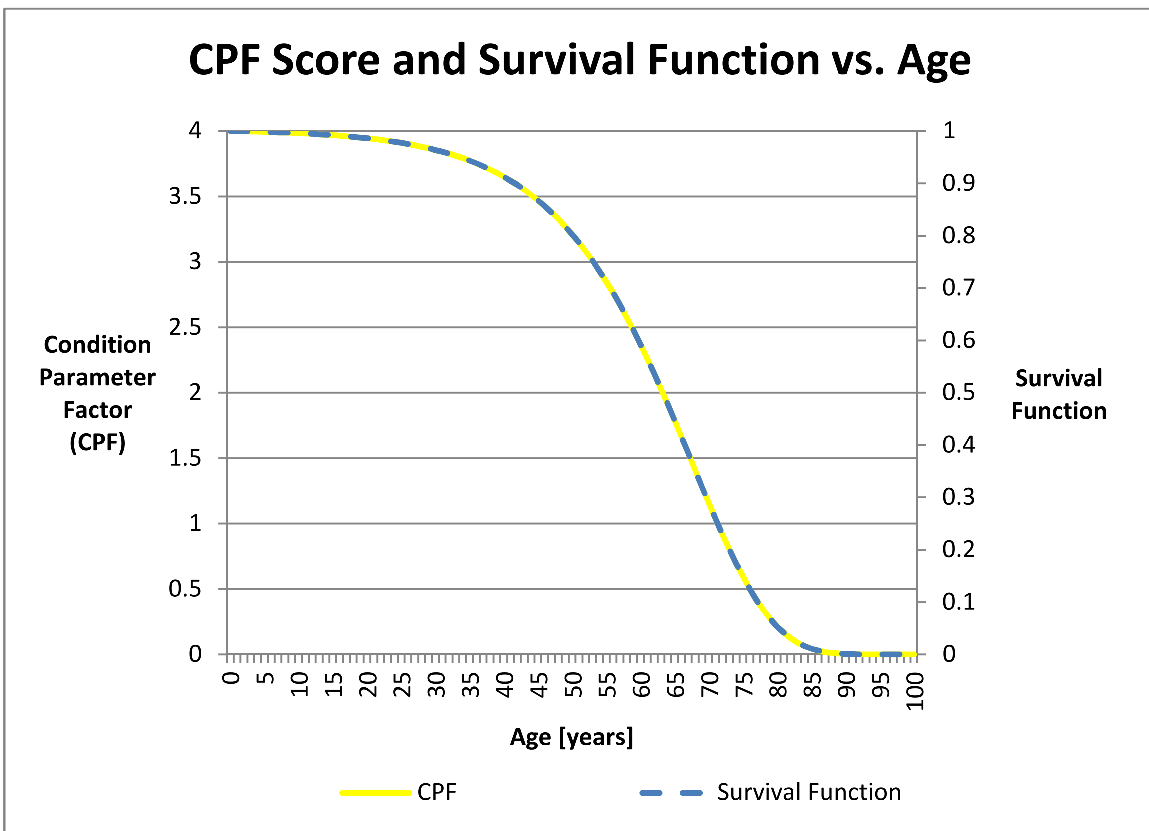


Figure 21-1 Vaults Age Condition Criteria

Inspection Results

Table 21-2 Vaults Inspection Condition Description and Score

Status	Score
Very Poor	0
Poor	1
Fair	2
Good	3
Very Good	4

21.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 99% of the population. The average age was found to be 23 years.

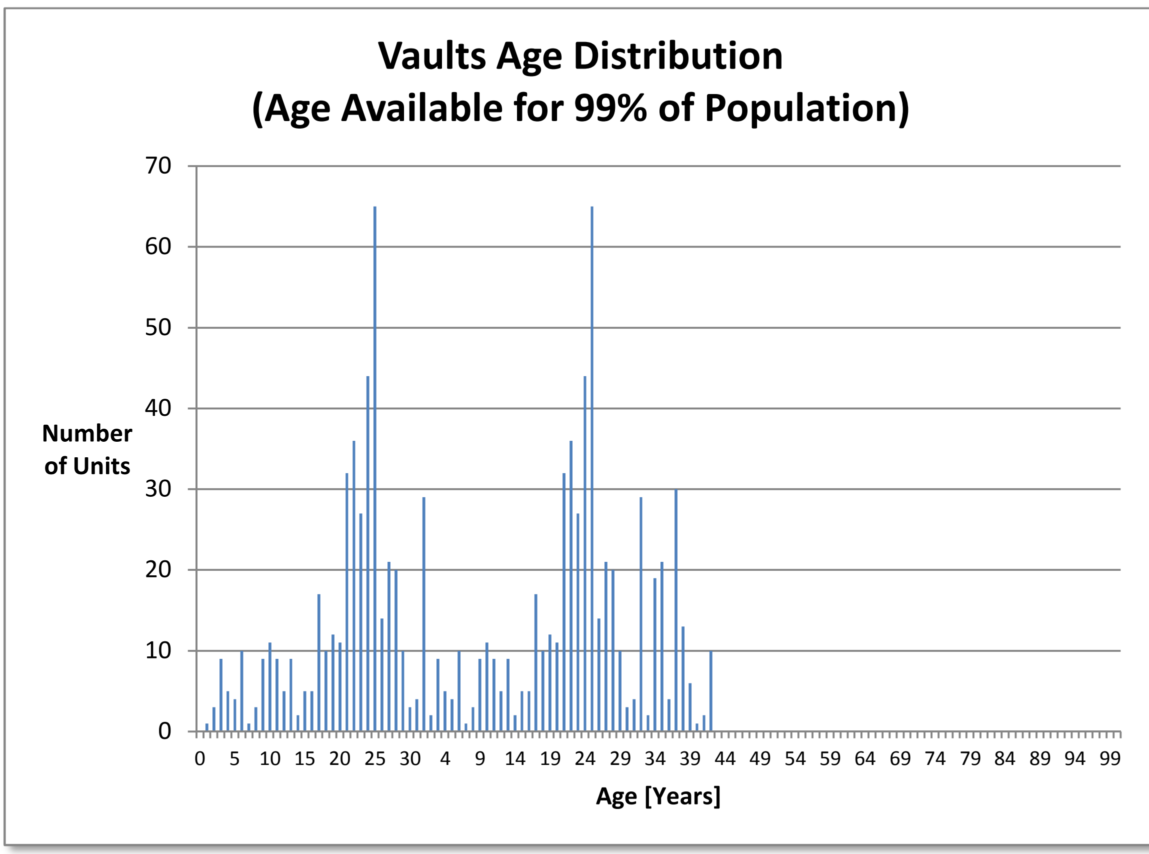


Figure 21-2 Vaults Age Distribution

21.3 Health Index Results

There are 560 in-service Vaults at GHESI. There were 66 units that were inspected and thus considered to have sufficient data for Health Indexing. It should be noted the 66 locations were specifically selected for various reasons (e.g. known issues, critical locations, locations where vaults would be more prone to degradation, etc.). As such, the samples may not be representative of the entire population and therefore the results cannot be extrapolated.

The average Health Index for this asset group is 58%. Approximately 27% of the units were found to be in poor condition.

The Health Index Results are as follows:

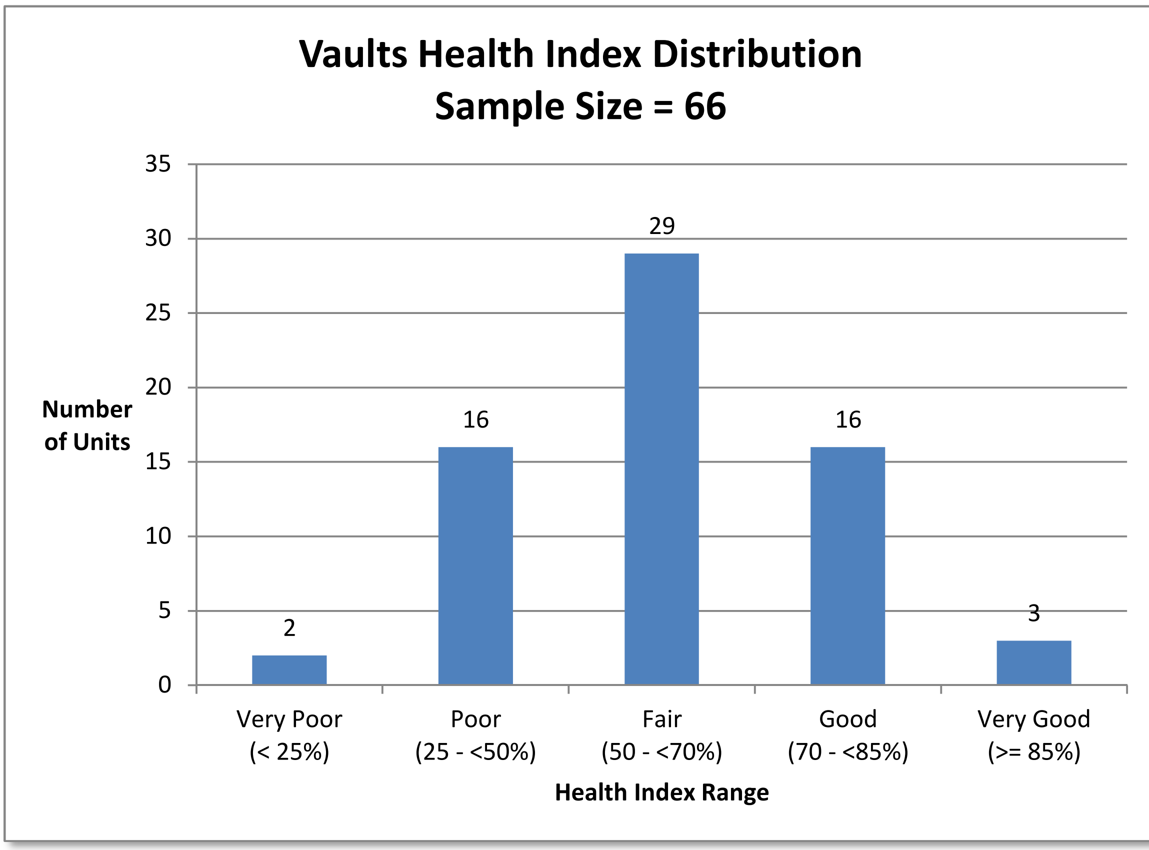


Figure 21-3 Vaults Health Index Distribution (Number of Units)

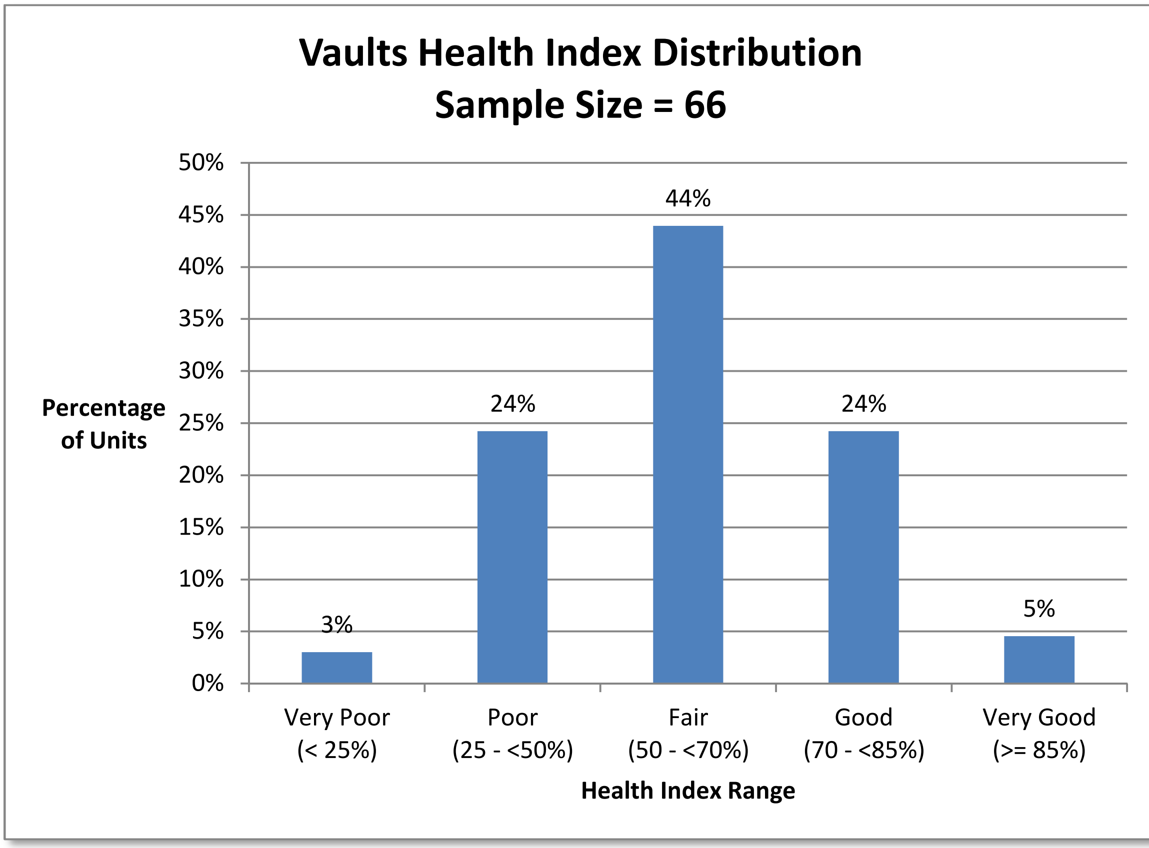


Figure 21-4 Vaults Health Index Distribution (Percentage of Units)

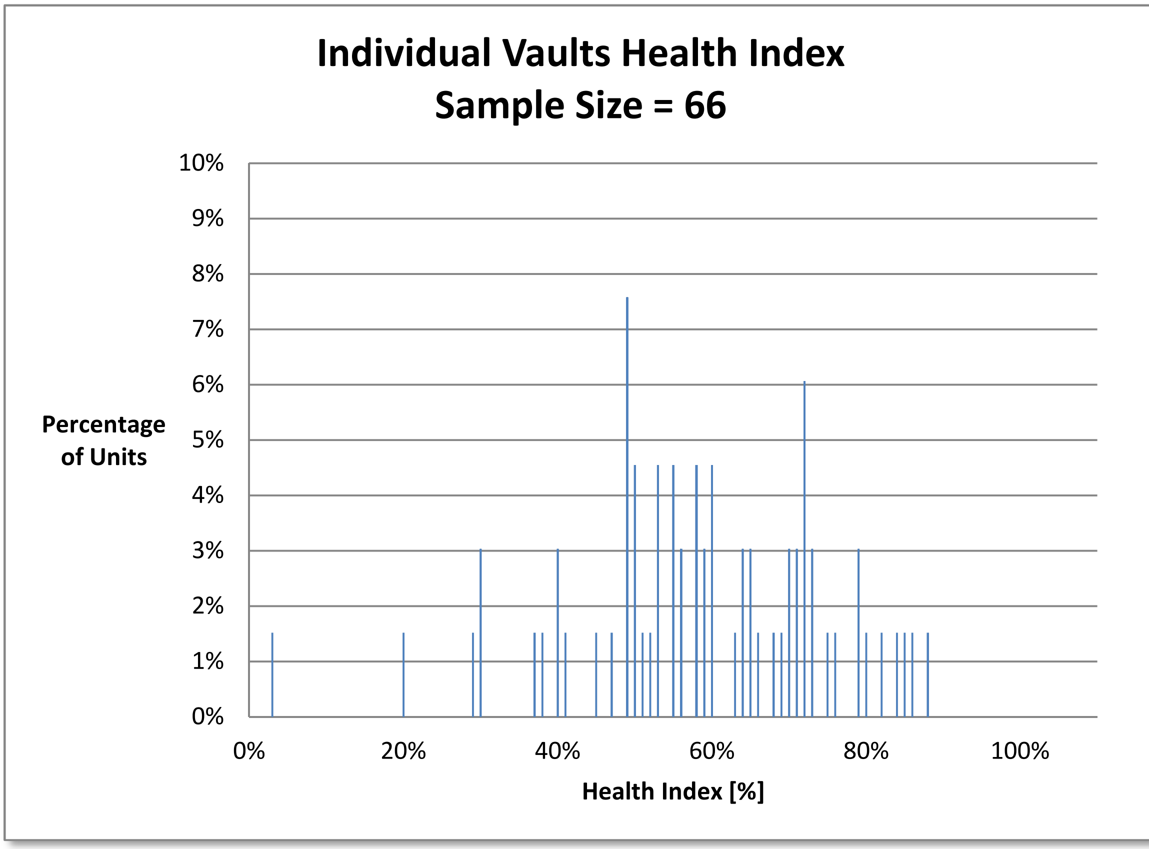


Figure 21-5 Vaults Health Index Distribution by Value (Percentage of Units)

21.4 Condition-Based Flagged for Action Plan

Although Vaults are proactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a “levelized” plan, based on accelerating or replacing prior to expected time of action, is also given.

Note that the flagged for action plan is based only on the sample size (66 units) and not extrapolated to the entire population (560 Vaults).

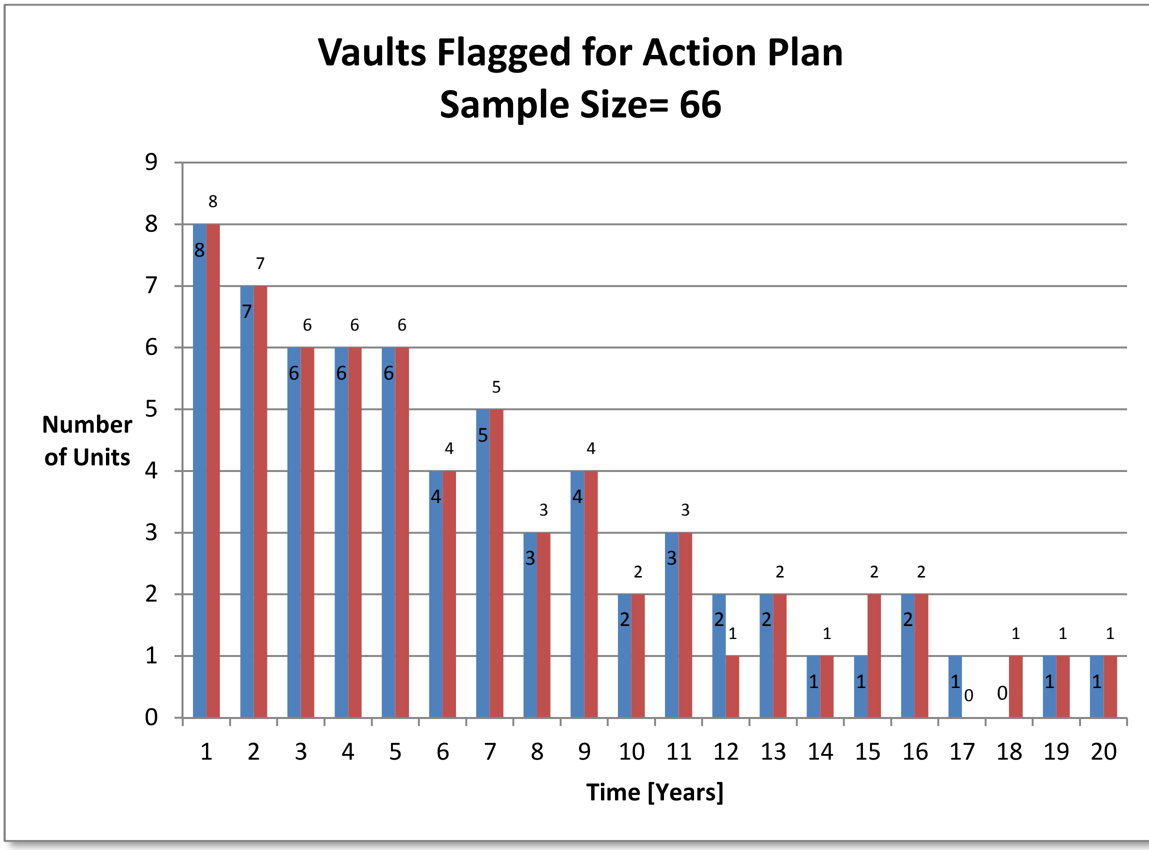


Figure 21-6 Vaults Condition-Based Flagged for Action Plan

21.5 Data Analysis

21.5.1 Data Gap

The data available for Vaults age and inspection records. No data gaps are identified. It should be noted, however that inspections were only conducted for approximately 12% of the population. The remaining 88% are assumed to have no data.

21.5.2 Data Availability Distribution

The average DAI for Vaults is 12%.

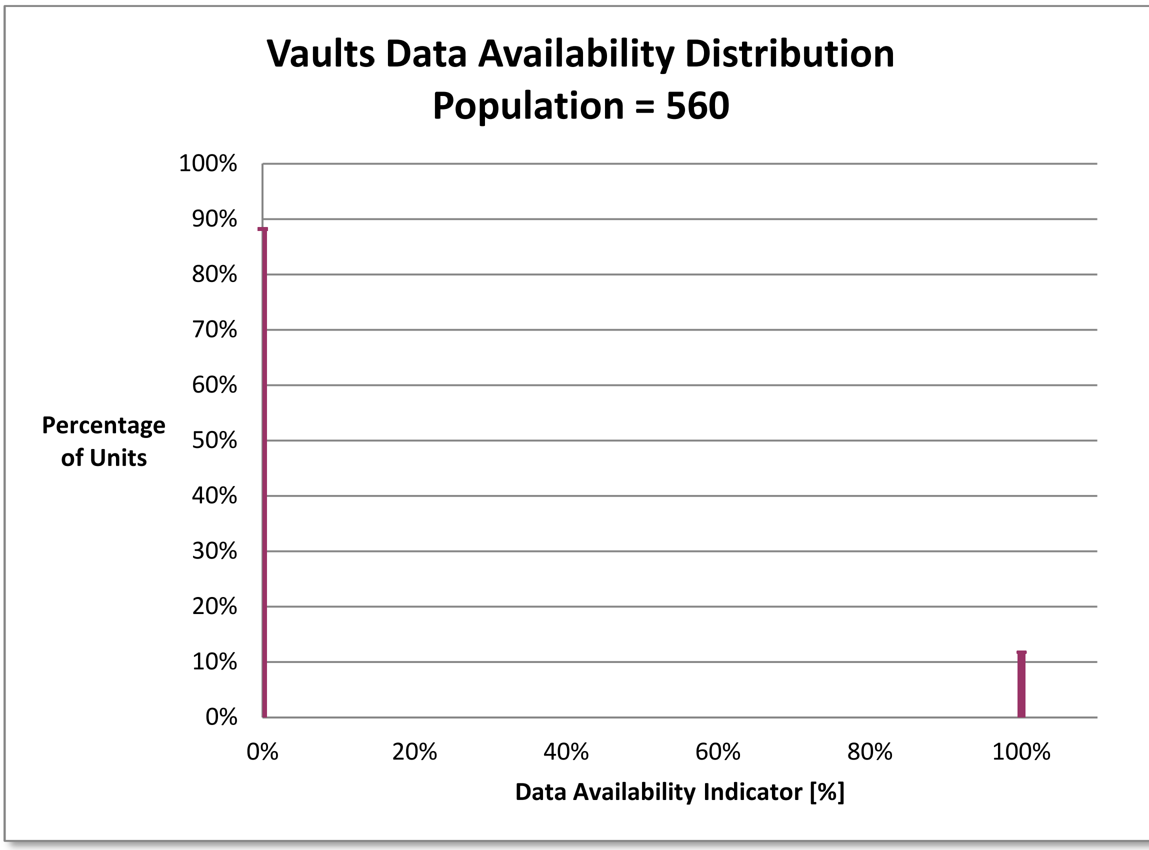


Figure 21-7 Vaults Data Availability Distribution

22 Manholes

22.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for GHESI Manholes. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

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”.

22.1.1 Condition and Sub-Condition Parameters

Table 22-1 Manholes Condition Weights and Maximum CPS

Condition Parameter	Condition Parameter Weight	Sub-Condition Parameter	Sub-Condition Parameter Weight			Criteria Lookup Table
Walls	6	North Wall	1	Cracks	8	Table 22-2
				Spalling	5	Table 22-2
				Corrosion	5	Table 22-2
		South Wall	1	Cracks	8	Table 22-2
				Spalling	5	Table 22-2
				Corrosion	5	Table 22-2
		East Wall	1	Cracks	8	Table 22-2
				Spalling	5	Table 22-2
				Corrosion	5	Table 22-2
		West Wall	1	Cracks	8	Table 22-2
				Spalling	5	Table 22-2
				Corrosion	5	Table 22-2
Floor	1	Cracks	8			Table 22-2
		Spalling	5			Table 22-2
		Corrosion	5			Table 22-2
Ceiling	10	Cracks	8			Table 22-2
		Spalling	5			Table 22-2
		Corrosion	5			Table 22-2
De-Rating Factor		Ceiling	If MIN(cracks, spalling, corrosion) = 0 de-rate 25% If MIN(cracks, spalling, corrosion) = 1 de-rate 50% If MIN(cracks, spalling, corrosion) = 2 de-rate 85%			

22.1.2 Condition Parameter Criteria

Age

Assume that the failure rate for Manholes 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 60 and 80 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

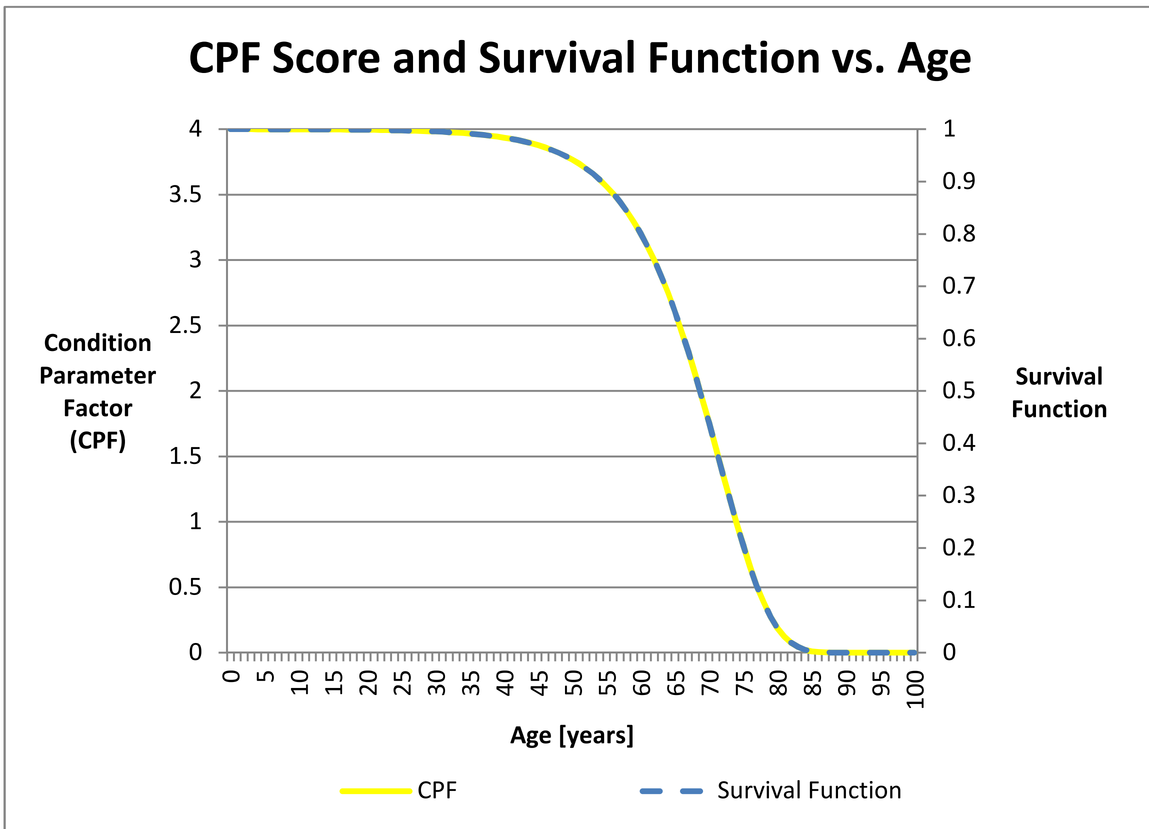


Figure 22-1 Manholes Age Condition Criteria

Inspection Results

Table 22-2 Manholes Inspection Condition Description and Score

Status	Score
Very Poor	0
Poor	1
Fair	2
Good	3
Very Good	4

22.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 18 years.

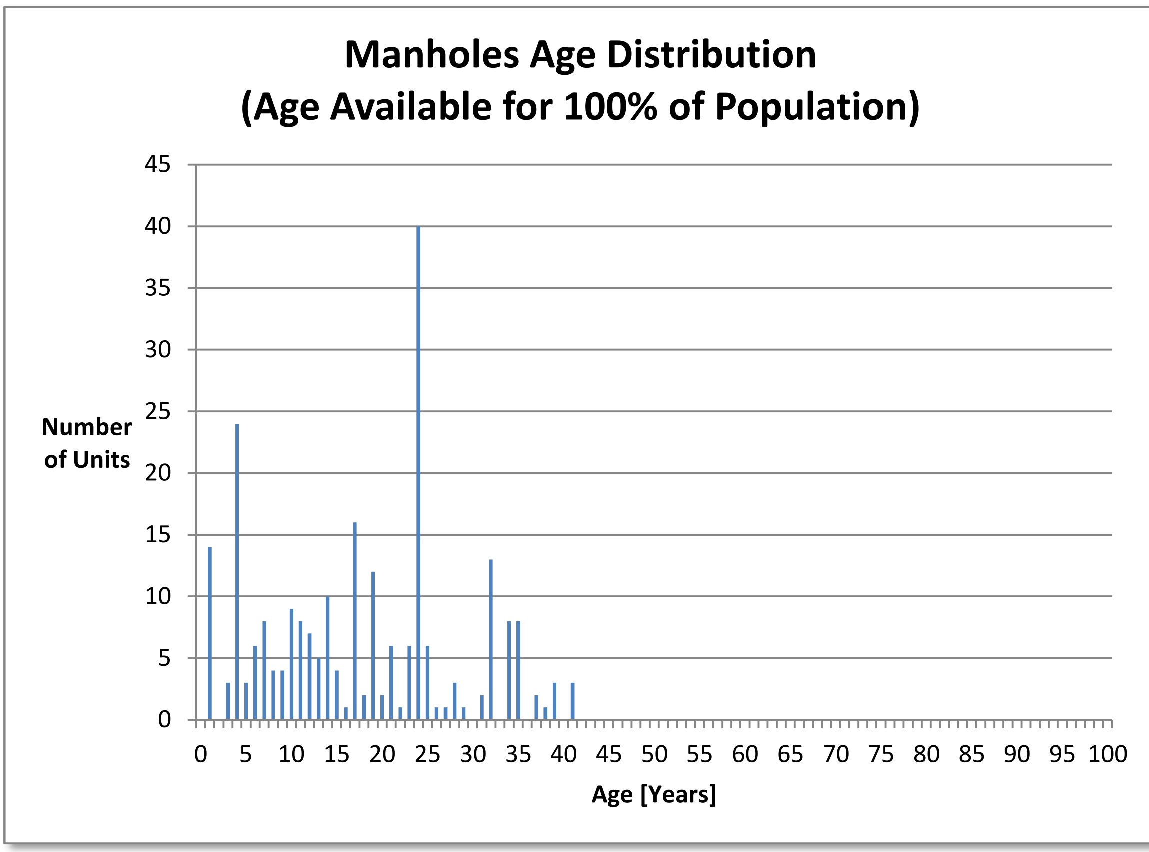


Figure 22-2 Manholes Age Distribution

22.3 Health Index Results

There are 247 in-service Manholes at GHESI. There were 33 units with sufficient data for Health Indexing. It should be noted the locations were specifically selected for various reasons (e.g. known issues, critical locations, locations where manholes may be more prone to degradation, etc.). As such, the samples may not be representative of the entire population and therefore the results cannot be extrapolated.

The average Health Index for this asset group is 51%. Approximately 39% of the units were found to be in poor condition.

The Health Index Results are as follows:

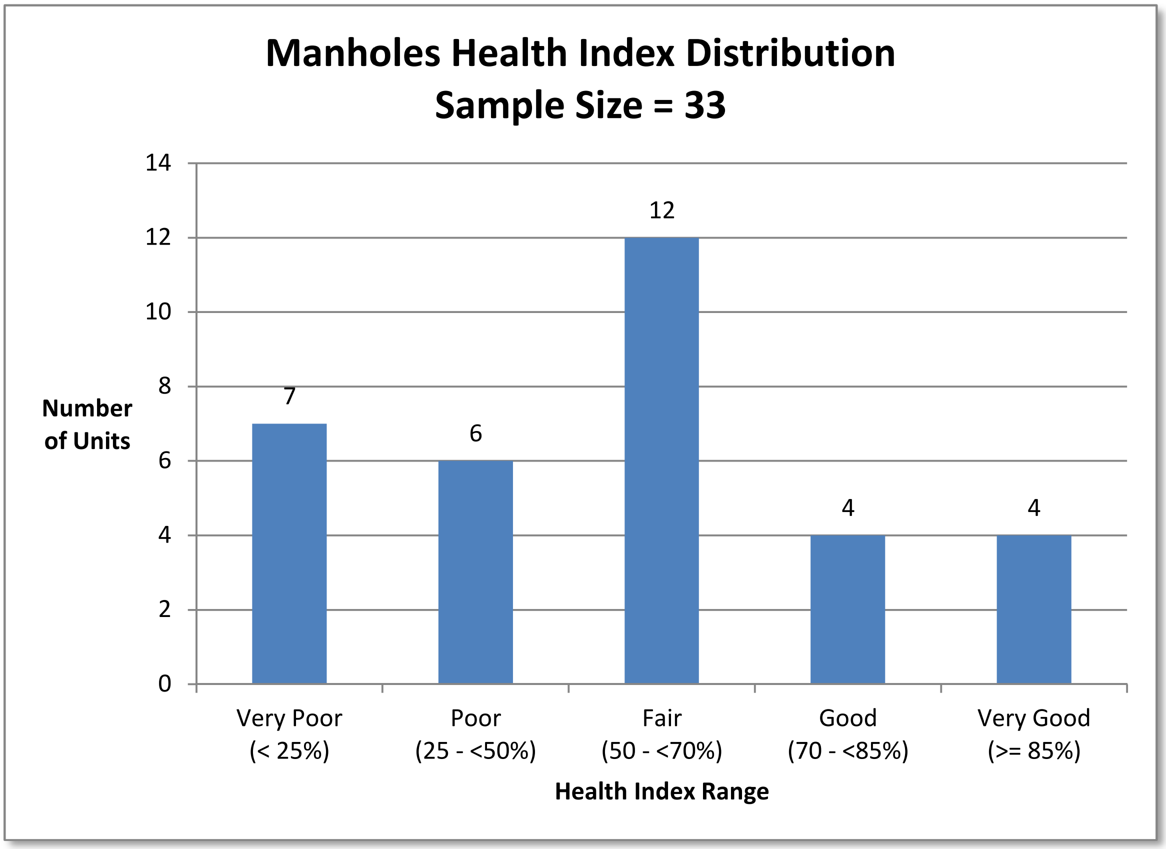


Figure 22-3 Manholes Health Index Distribution (Number of Units)

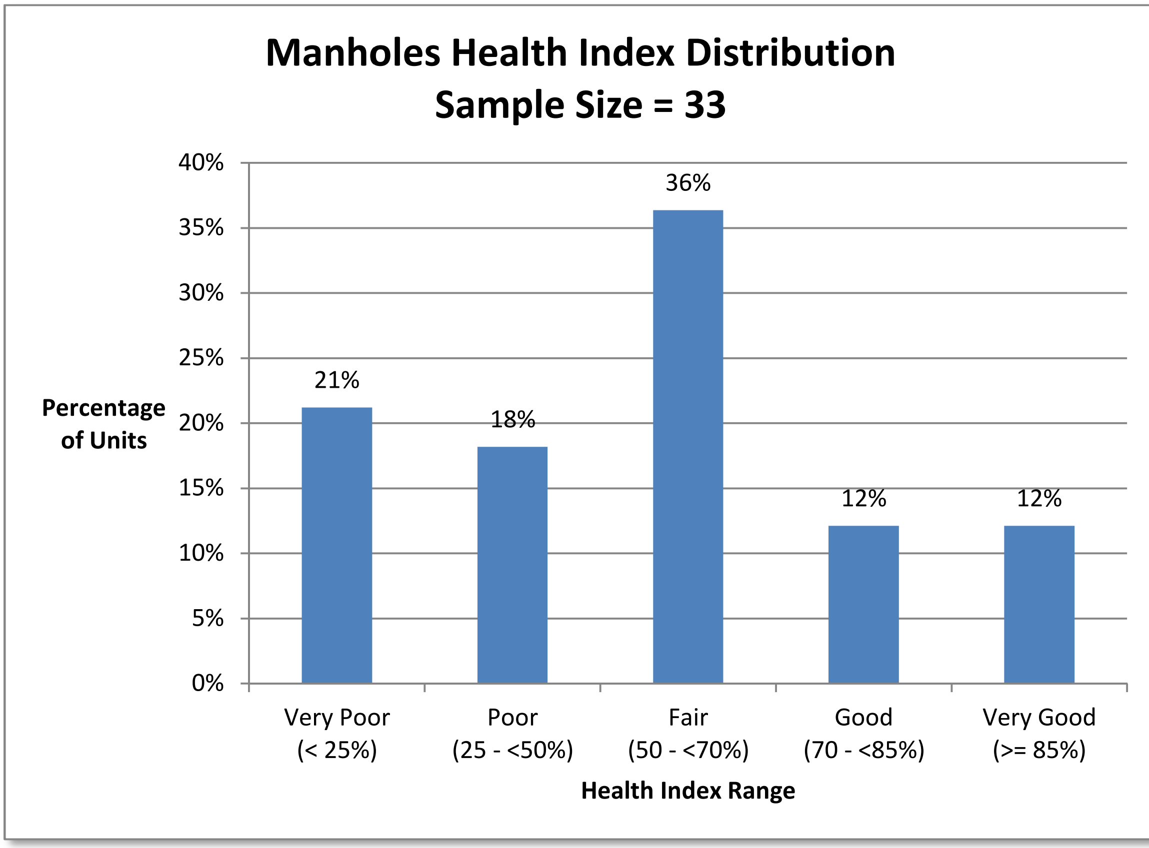


Figure 22-4 Manholes Health Index Distribution (Percentage of Units)

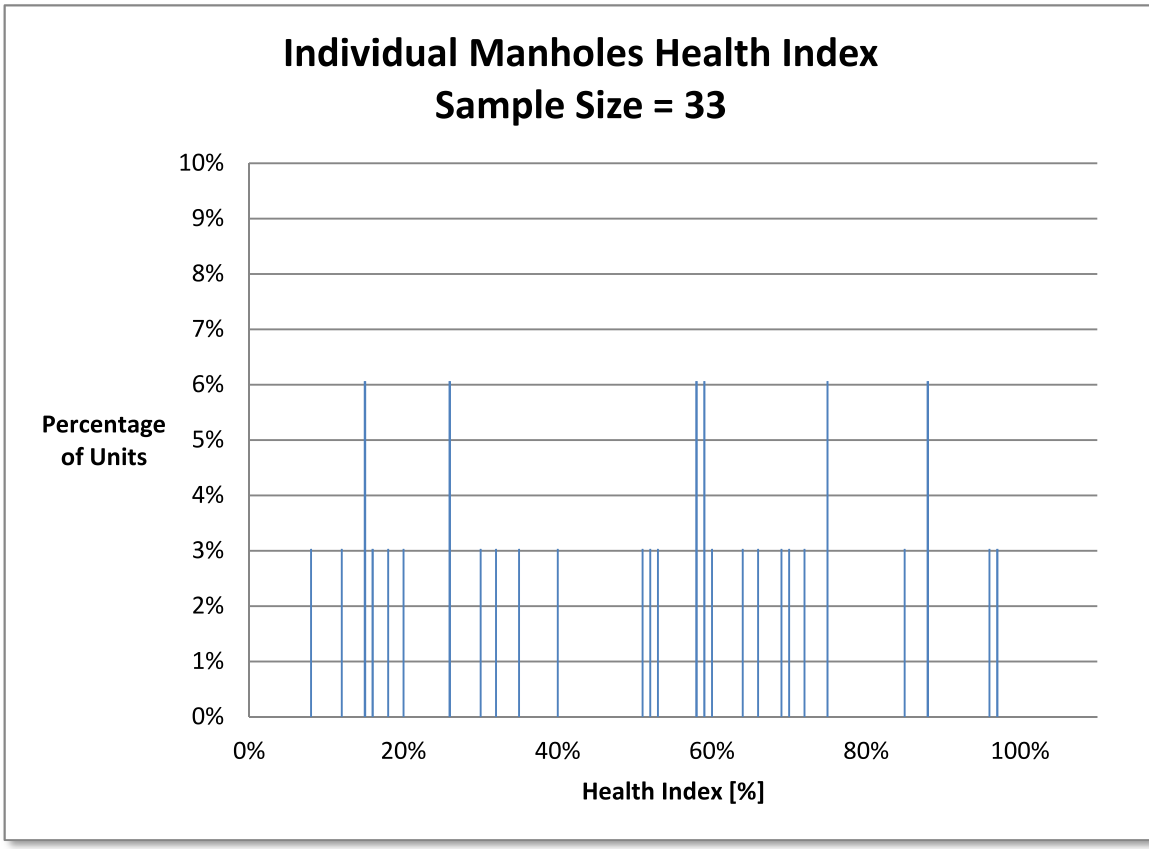


Figure 22-5 Manholes Health Index Distribution by Value (Percentage of Units)

22.4 Condition-Based Flagged for Action Plan

Although Manholes are proactively addressed, the flagged for action plan is based on asset failure rate f(t), as described in Section II.2.2.

The optimal flagged for action plan is based on the number of expected failures in a given year. As it may not always be feasible to act as per the optimal plan, a "levelized" plan, based on accelerating or replacing prior to expected time of action, is also given.

Note that the flagged for action plan is based only on the sample size (33 units) and not extrapolated to the entire population (247 Manholes).

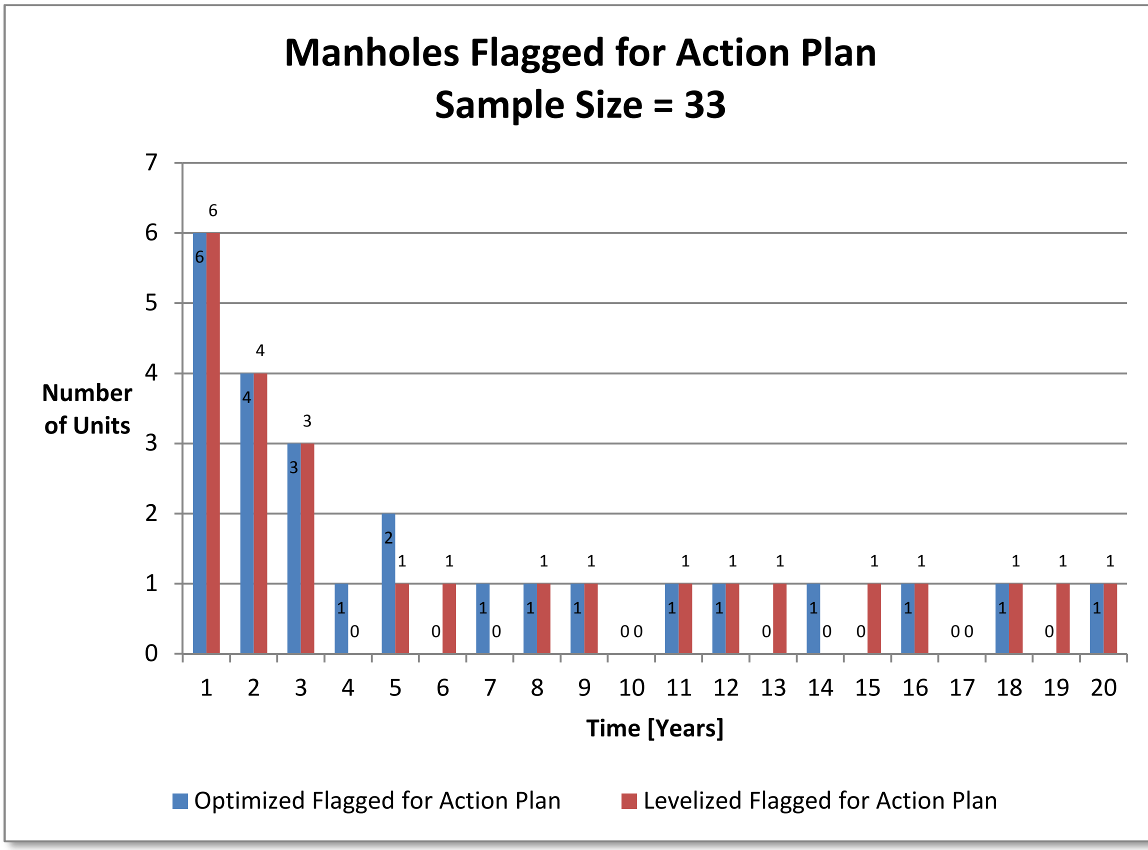


Figure 22-6 Manholes Condition-Based Flagged for Action Plan

22.5 Data Analysis

22.5.1 Data Gap

The data available for Manholes age and inspection records. No data gaps were identified for this asset category. It should be noted, however that inspections were only conducted for 13% of the population.

22.5.2 Data Availability Distribution

The average DAI for Manholes is 13%.

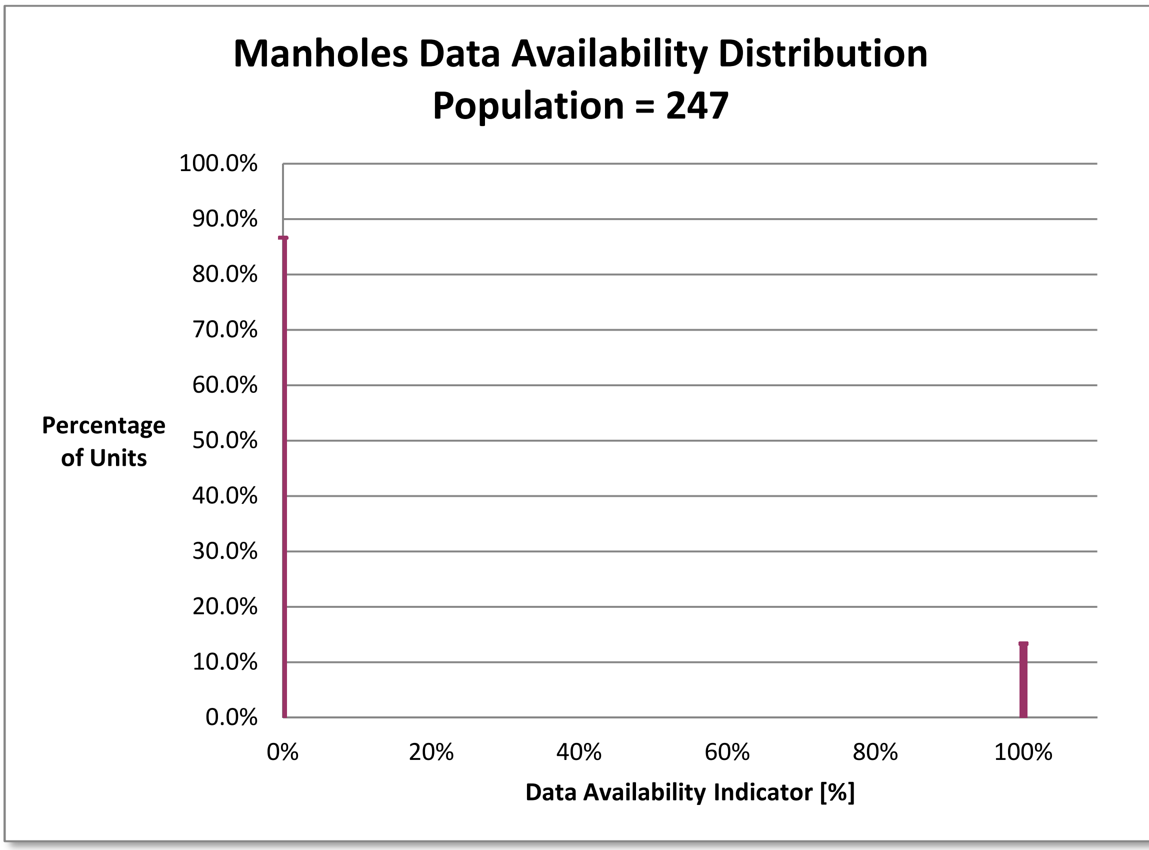


Figure 22-7 Manholes Data Availability Distribution

This page is intentionally left blank.

VII REFERENCES

This page is intentionally left blank.

VII References

Aichinger, Richard F. and Huang, John C. Introduction to Steel Utility Poles. http://www.pdhonline.org/courses/s114/s114.htm

B. Gompertz, "On the Nature of the Function Expressive of the Law of Human Mortality, and on a New Mode of Determining the Value of Life Contingencies," Philosophical Transactions of the Royal Society of London, Vol. 115, pp. 513-585, 1825

Cress S.L. et al, "Utility Guide to Root Cause Analysis of Distribution Failures" CEATI Report No. T074700-5068, February 2010.

Hjartarson T, Jesus B, Hughes D.T., Godfrey R.M., "The Application of Health Indices to Asset Condition Assessment", presented at IEEE-PES Conference in Dallas, September 2003.

Tsimberg, Y., et al, "Asset Depreciation Study for the Ontario Energy Board", Kinectrics Inc. Report No: K-418033-RA-001-R000, July 8, 2010

W. M. Makeham, "On the Law of Mortality and the Construction of Annuity Tables," J. Inst. Actuaries and Assur. Mag. 8, 301-310, 1860

Wang F., Lotho K., "Condition Data Requirements for Distribution Asset Condition Assessment", CEATI International, 2010

Willis H.L., Welch G, Randall R. Schrieber, " Aging power delivery infrastructures", Marcel Decker Inc., 2001

This page is intentionally left blank.

Appendix JT1.36: Board Staff's July 6, 2015 presentation - Rate Design – Commercial / Industrial Stakeholder Consultation

Ontario Energy Board
Commission de l'énergie de l'Ontario

Rate Design – Commercial/Industrial

Stakeholder Consultation

July 6, 2015

Agenda

- Ontario status
- Jurisdictional review
  - General issues review
    - EPRI
    - Regulatory Assistance Project
  - Policy directions under development
    - California
    - New York State
    - Australia
- Board policy and objectives
- Objectives for Commercial/Industrial rates
- Staff identified issues for discussion

Ontario status

- Flat or falling electricity demand
  - Conservation First
    - Conservation
    - Distributor-connected distributed energy resources
  - De-industrialization
  - Grid parity
- Investment to replace aging infrastructure
  - Like-for-like or ?
  - Enabling investments to increase local generation penetration?
- The role of the distributor

CONFIDENTIAL

Economics of Load Defection (EPRI)

- Evolved pricing and rate structure
  - *Locational*, allowing some form of congestion pricing
  - *Temporal*, allowing for continued evolution of time-of-use pricing or real-time pricing
  - *Attribute-based*, breaking apart energy, capacity, ancillary services, and other service components
- New business model: for two way flow
- New regulatory models:
  - Maintain and enhance fair and equal access
  - Recognize, quantify, and appropriately monetize both the benefits and costs for DER
  - Preserve equitable treatment for all customers, including the grid-dependent

Time-Varying and Dynamic Rate Design (RAP)

- Pricing not to induce individual response but to reward customers for allowing their demand response to be aggregated.
- Examples of time-varying charges in capacity limited resources:
  - Commuter trains; bridges; parking spaces; road tolls; [cell phones; internet]
- Time-of-use: static charges based on TOU
- Dynamic charges: “dispatchable” varying charges available on a day-ahead or day-of basis

CONFIDENTIAL

California

- Has had a tiered, consumption-based, inclining block rate
- Introducing and gradually increasing a fixed customer charge ($5 to $10)
  - Distribution network, metering and billing
- TOU to deal with generation
  - Duck load shape – match actual hours
  - Over-generation from renewables in shoulder season
  - Peak, super-peak, off-peak & super off-peak

New York State

- Track 1: Distributed System Platform Provider (DSP)
  - to integrate Distributed Energy Resources into planning and operation of the grid
  - market solutions
- Track 2: Rate Design
  - delayed until July 1, 2015

Australia

- What is distribution service?
  - Customer choice in levels of service and reliability
  - Distributor choice in provision of service

CONFIDENTIAL

Board policy and objectives

- The Board's policy in revising rate design for electricity and natural gas in all rate classes is *"to increase the amount of revenue recovered through fixed charges."*
- Develop a new rate for GS<50kW
- Develop a new rate for GS>50kW
- Business Plan FY 2014
  - Initiate development of new time-sensitive distribution rates for large customers.

Objectives for Commercial/Industrial

- To support innovation for customers given the evolution of supply:
  - Customers' ability to leverage new technology;
  - Customers' ability to manage their bill through conservation; and
  - Customers' understanding of the value of connection.
- To increase fairness of cost recovery:
  - To maximize use of the current system; and
  - To optimize investment for long-term cost containment.
- To stabilize distribution revenue:
  - To enable technology changes;
  - To support conservation;
  - To facilitate investment planning.

Staff identified issues for discussion

- ***Valuing distributed energy resources*: What treatment of distributed energy resources would recognize the costs and benefits of these resources to the system? What are the implications for customers who do not participate?**

- ***Valuing connection to the system*: The Board has typically allocated costs to a fixed charge based on a minimum system process. Given the Board's policy, what is the appropriate approach?**

- ***Valuing capacity*: What price signals will align the interests of customers and distributors to maximize use of the system and contain long-term costs?**

- ***Rate stability*: Customers moving from one rate class to another can find that their bill changes dramatically. How can Commercial/Industrial rates be designed to avoid that sudden transition at the boundaries of rate classifications?**

- ***Rate goals*: Stakeholder comments on the previous project suggested that a desirable rate design would be: cost driven; customer controlled; forward looking; and induce conservation. Are these the appropriate goals?**

Appendix JT1.37: Guelph Hydro Business Case for Smart Meter ZigBee® Chip

Guelph Hydro
Electric Systems Inc.

Business Case

for

Smart Meter

ZigBee® Chip

Table of Contents

Executive Summary

Guelph Hydro included a "beyond-minimum-functionality" feature known as a ZigBee® chip in its residential and small commercial customer smart meter program deployment. The ZigBee chip is a small, limited range, low-power digital radio communication chip, used in low data rate applications that require secure networking.

Through its Conservation and Demand Management (CDM) delivery work, Guelph Hydro foresaw the inclusion of the ZigBee chip as a cost-effective means to enable future residential CDM programs, as well as other potential customer education and customer engagement applications.

Guelph Hydro has demonstrated the successful use of the ZigBee chip to deliver the IESO's *peaksaver*PLUS® Residential Demand Response (RDR) CDM program, with program participants receiving an In-Home Display (IHD) wirelessly connected through the customer's smart meter ZigBee chip to provide real-time electricity consumption, Time-of-Use pricing, as well as Critical Peak pricing (if required) information.

Other potential future use applications include "*Residential Demand Response Thermostats*", "*Home Automation*", *"High Resolution Residential Load Disaggregation", among others*.

Put simply, the ZigBee chips are used and useful - they are providing a benefit to ratepayers today, and ZigBee chip utilization is expected to continue to grow as future use cases are implemented.

The incremental ZigBee chip cost was approximately $12.25 per unit, with an annual Residential customer bill impact of $1.90 per year, or $0.16 per month.

In addition to being used and useful, the initial modest investment in the ZigBee chip technology was an entirely prudent decision. By implementing the ZigBee chip, Guelph Hydro can now support the interconnectivity necessary to facilitate:

- enhanced customer engagement (through meter-based information exchange);
- enhanced and better targeted CDM programs; and
- the implementation of future smart grid technologies.

1.0 ZigBee Chip Description

Guelph Hydro Electric Systems Inc.'s (Guelph Hydro) residential and small commercial (<50kW) customer smart meter deployment included a "beyond–minimum-functionality" feature known as a ZigBee® chip.

ZigBee is a specification for a suite of high-level communication protocols, based on an IEEE 802.15.4 standard. ZigBee is typically implemented as a small, cost-effective, limited range, low-power digital radio communication chip, used in low data rate applications that require secure networking (ZigBee networks are secured by 128 bit encryption keys).

ZigBee is best suited for intermittent data transmissions from a sensor or input device. ZigBee-enabled devices can transmit data over longer distances by passing data through a secure mesh network of intermediate ZigBee enabled devices to reach more distant ones, effectively creating a secure personal area network. Applications include wireless light switches, electrical meters with in-home-displays, traffic management systems, and other consumer and industrial equipment requiring low-rate wireless data transfer.

2.0 ZigBee Application Specifications

ZigBee application specifications are developed by the ZigBee Alliance, an open, non-profit association of approximately 400 global members. These members provide the foundation for the "Internet of Things" by enabling simple and smart objects to work together, to improve comfort and efficiency in everyday life for use in consumer, commercial and industrial applications.

Some of the developed ZigBee specifications are related to Retail Services, Telecommunications and Health Care, and are less relevant to Guelph Hydro's smart meter ZigBee Chip deployment. Other specifications are of greater interest with respect to either existing or potential future applications, including:

- ZigBee Home Automation 1.2;

- Smart Energy 1.1b and 2.0;
- Building Automation 1.0; and
- Green Power 1.0 (Optional feature of ZigBee 2012).

As an example, the ZigBee Smart Energy 2.0 specifications define an IP-based protocol to monitor, control, inform and automate the delivery and use of energy and water. Smart Energy 2.0 is an enhancement of Smart Energy 1.X specifications, supporting the following added features:

- Services for plug-in electric vehicle (PEV) charging;
- Installation, configuration and firmware download;
- Prepay services;
- User information and messaging;
- Load control, demand response and common information and application profile interfaces for wired and wireless networks.

3.0 ZigBee Application Specification Use Cases

The following describes various use cases that could be operationalized through the implementation of ZigBee-enabled devices and / or applications, and may be relevant to future programs utilizing Guelph Hydro's ZigBee chip deployment.

HVAC: Heating, ventilation and air conditioning (HVAC) systems can include temperature and humidity control, as well as fresh air heating and natural cooling. A homeowner can use an internet-enabled thermostat to control the building's heating and air conditioning systems remotely. The system may automatically open and close windows to cool the house, and may use a dedicated gateway to connect an advanced HVAC system with Home Automation (HA) and Building Management System (BMS) controllers for centralized control and monitoring.

Lighting: A lighting control system can be used to switch lights based on a time cycle, or arranged to switch off when a room is unoccupied. Some electronically controlled lamps can be adjusted for brightness or color to provide different light levels for different tasks. Lighting can be controlled remotely by a wireless control or over the internet. Natural lighting (daylighting) can be used to automatically control window shades and draperies to make the best use of natural light.

Shading: Automatic control of blinds and curtains can be used for presence simulation, privacy, temperature control, brightness control, and security in case of shutters.

Home Automation: Home Automation is the residential extension of building automation. A home automation system integrates electrical devices in a house. It typically includes centralized monitoring and control of lighting, HVAC, appliances and security systems, to provide improved convenience, comfort, energy efficiency and security. It may support the control of domestic activities, such as home entertainment systems, houseplant and yard watering, pet feeding, or changing ambiance "scenes" for events such as dinners or parties. It may also simulate the appearance of an occupied home by automatically adjusting lighting or window coverings. Swimming pool systems or detection systems such as fire alarm, gas leak, carbon monoxide, or water leak detectors can also be integrated. Personal medical alarm systems can permit an injured home occupant to summon help. Devices are often connected through a home network to allow control by a personal computer, potentially with remote internet access.

4.0 Guelph Hydro Target Market

The provincial smart meter initiative was strictly focused on residential and small commercial (<50kW) customers. Program timelines included a requirement for smart meters to be installed at 800,000 homes by large distributors by the end of 2007, and in every Ontario home by December 31, 2010.

During this time the province was also looking at developing a new 2011-2014 Conservation and Demand Management (CDM) framework through the Ontario Power Authority (OPA). Guelph Hydro's smart metering implementation team had responsibility for 2007-2010 CDM program delivery, and through its involvement with the evolution of residential CDM programming, Guelph Hydro believed that ordering smart meters without a ZigBee chip would limit its ability to offer future residential CDM programs in support of building a culture of conservation, or would result in much greater cost in the future to replace with other meters that did have this functionality.

The ZigBee chip must be specified at the time of smart meter order, as smart meters deployed in Canada cannot be readily retrofitted with the chip. Retrofitting smart meters requires breaking the Measurement Canada meter seal, disassembling the meter, replacing the network card and retesting, recertifying and resealing the meter. While it is more cost effective to purchase and deploy a new smart meter with a ZigBee chip, this raises the prospect of the additional cost of scrapping the replaced meter before the end of its useful life. Guelph Hydro believed that it was prudent to include the communication chip in the smart meters on the basis that the incremental cost to do so was minor ($12.25/meter) compared to the alternative of having to replace large volumes of meters before the end of their useful lives (15 years).

5.0 Regulatory Requirements

Guelph Hydro notes that the ZigBee chip is an enabling technology that requires additional technology, services or programs, such as CDM, customer education or customer engagement, to fully demonstrate the benefits available to Guelph Hydro and its customers.

Guelph Hydro highlights the following “Renewed Regulatory Framework for Electricity, 2012” (RRFE) requirements for distributors that are supported by the utilization of the ZigBee chip, further described in Section 6.0:

- *facilitating customer access to consumption data in an electronic format; and*
- *facilitating “real-time” data access and “behind the meter” services and applications for the purpose of providing customers with the ability to make decisions affecting their electricity costs.*

Guelph Hydro notes that under RRFE, distributor performance will be measured under the following categories on new "Electricity Distributor Scorecards", again supported by the utilization of the ZigBee chip both to assist CDM target achievement, as well as a smart grid enabling tool:

- *Customer Focus: services are provided in a manner that responds to identified customer preferences; and*
- *Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).*

Guelph Hydro further notes the following "Ontario Energy Board Act, 1998" policy objectives that are supported by the utilization of the ZigBee chip, further described in Section 6.0:

- *to promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario; and*
- *to facilitate the implementation of a smart grid in Ontario.*

6.0 Guelph Hydro ZigBee Applications and Potential Use Cases

The ZigBee chip can enable enhanced services including the provision of "real-time" electricity price and consumption information to energy consumers which would permit customers to better understand and manage their energy use, when paired with devices such as an In-Home Display (IHD). It can provide real time Time-of-Use price signaling and demand response capability, and may facilitate increased load shifting and conservation through the wireless connection to demand response thermostats and ZigBee enabled smart appliances. Other potential applications, such as home automation, are further described below.

peaksaverPLUS In-Home Display: Guelph Hydro has demonstrated the successful use of the ZigBee chip to support its delivery of the IESO's *peaksaver*PLUS® Residential Demand Response (RDR) CDM program. Participants enrolled in the program permit the installation of a demand response switch or demand response thermostat to control their central air conditioner on a small number of summer days when the Ontario grid is supply constrained. The participant receives an In-Home Display (IHD) which is wirelessly connected through the customer's smart meter ZigBee chip to provide real-time electricity consumption, Time-of-Use pricing, as well as Critical Peak pricing (if required) information. This tool provides the potential for customers to better educate themselves on their electricity use, the approximate cost to operate various devices inside the home, while reinforcing the principles of Time-of-Use Rates. Ideally customers will better manage their electricity consumption, which in turn may assist Guelph Hydro in achieving its conservation targets.

peaksaverPLUS Demand Response Thermostat: While sourcing and testing ZigBee enabled IHDs for the *peaksaver*PLUS® RDR program, Guelph Hydro also tested a small number of ZigBee-enabled demand response thermostats. For the RDR program rollout Guelph Hydro decided to offer customers their choice of one of two different IHDs, but not the demand response thermostat.

Conservation First Framework "Connected Home": Under the 2015-2020 Conservation First Framework (CFF), new conservation program design is a distributor responsibility to be supported by the IESO. The conservation portfolio is separated into "Residential" and "Non-Residential" Programs. The Residential Program Working Group has established several Subcommittees, including a "Connected Home" subcommittee that is exploring Smarthomes / Whole Home Solutions. This includes developing a strategy and business case to evolve the existing *peaksaver*PLUS® program to a "Connected Home" conservation program, with a preliminary province-wide electricity savings target of approximately 350 GWh by 2020. Guelph Hydro expects that the outcome of the "Connected Home" initiative will be compatible with the capabilities offered by the ZigBee chip investment, and may target some of the "*ZigBee Application Specification Use Cases*" identified in Section 3.0.

High Resolution Residential Load Disaggregation: With the introduction of smart meters, Ontarians have been provided with a wealth of hourly interval electricity consumption information previously not available. Through third party load disaggregation service providers, this hourly consumption data can be used and combined with customer information to provide further insights and "intelligence" into the customer's home energy usage and potential energy savings opportunities. One of the issues with Load Disaggregation using hourly consumption data is that only very large energy usage profiles (i.e. 3-4 large energy use appliances) can be discerned through the tool. Through the use of a ZigBee enabled gateway wirelessly connected to the customer's smart meter, much higher resolution (i.e. 10-60 second) data can be retrieved from the smart meter. This allows the load disaggregation tool to resolve many more appliances within the home, and provides for better energy usage insights and potential savings opportunities. Applications such as these often provide mobile device energy use reporting, anomaly (i.e. high usage) notifications, as well as the potential for anonymous comparisons with other electricity consumers.

Mobile Applications: For customers that are focused on mobile devices with mobile applications ("apps"), Guelph Hydro notes that many third-party gateway-based technology offerings also include apps that provide the same feature-rich experience as the desktop offerings. For example, customers selecting one of Guelph Hydro's IHD choices, the "CEIVA HomeView Frame", are offered a mobile version of the energy display portal under a subscription service. The High Resolution Residential Load Disaggregation service providers described above also offer mobile apps and include a more regular customer outreach and engagement experience that could be utilized by a distributor for further enhanced energy management target setting, neighbourhood comparisons, notifications as well as energy literacy and education.

Other Potential Use Cases: Based on the breadth of the ZigBee open source protocols, global support by numerous members including Nest thermostats (Google), Hue lighting (Philips), and Hive (British Gas), as well as ongoing technological advancements, Guelph Hydro believes it is reasonable to anticipate that over the estimated 15-year smart meter lifespan, other programs and initiatives will arise that could make use of the ZigBee chip's functionality. The ZigBee ecosystem has the potential to support smart refrigerators, smart plugs, smart gateways, Home Automation and advanced energy monitoring systems that could connect residential renewable energy generation, energy storage, and electric vehicle charging stations.

7.0 Financial Impact

The following "financial impact" discussion is focussed on the cost of the ZigBee communications chip as an enabling technology. As previously noted, additional technology, services or programs, such as CDM, customer education or customer engagement are required to realize the benefits available to Guelph Hydro and its customers. The cost of related technology, services and / or program implementation is briefly discussed in Section 8.0 "*Implementation*".

Guelph Hydro's smart meter deployment capital cost was $9,942,320, with an average per meter capital cost of $190.28. The cost of the ZigBee chip was $12.25 per meter, or only 6.4% of the installed per meter cost.

When the ZigBee chip expense is framed as smart meter program revenue requirement recovery, the annual impact on a per Residential customer basis, is calculated as $1.90 per year, or $0.16 per month, as cited on page 6 of Guelph Hydro's Argument-In-Chief filed December 14, 2011 (EB-2011-0123) and page 2 of SEC's Submissions filed on January 5, 2012.

As discussed in Section 4.0 "*Guelph Hydro Target Market*", it is impractical to retrofit smart meters not equipped with the ZigBee chip. This meant that when procuring smart meters for its deployment, Guelph Hydro management had a decision to make, either:

1. implement ZigBee chip functionality at an incremental cost of $12.25 per meter, resulting in a total average cost per meter of $190.28 over the total useful life (15 years), or $12.68 per year; or
2. implement non-ZigBee enabled smart meters at a total average cost per meter of $178.03, and run the risk of having to remove non-ZigBee smart meters prior to their 15 year useful life and replace them with ZigBee enabled smart meters.

If, for example, the ZigBee functionality would be needed at year 7.5, the total average cost per meter of implementing the non-ZigBee enabled smart meters on day one would be \$178.03 (non-ZigBee smart meter cost) plus an additional \$190.28 at year 7.5 to replace it with a ZigBee smart meter, totaling \$368.31 *(ignoring the time value of money and ignoring the cost of labour to replace the meter, for simplicity)*. The total useful life of the meters in this scenario would be 22.5 years (7.5 years plus 15 years), resulting in a total average cost per meter per year of \$16.37.

Guelph Hydro further notes that the cost of adding this functionality later, by field-replacing smart meters not equipped with the ZigBee chip at the time of smart meter purchase, would be significantly higher, perhaps as much as twenty times or more of the cost of building in the chip at the outset.

When considered in light of the ZigBee chip utilization for CDM programming to date, as well as the potential future benefits available to customers, Guelph Hydro submits that the benefits of the chip to customers far outweighs the costs. The cost of the ZigBee chip is small relative to the overall smart meter program cost, and relative to the overall bill impact of \$1.90 per residential customer per year.

8.0 Implementation

The following "implementation" discussion will touch on additional technology, services or programs required to realize the benefits the ZigBee chip can enable.

In order to provide real-time secure data transmission between the Guelph Hydro's smart meters and a ZigBee-enabled IHD under the *peaksaver*PLUS® RDR CDM program, additional back-office software is required to manage the IHD inventory and the process of pairing and commissioning a specific IHD to a specific customer smart meter. This software is also used to program and track Time-of-Use rates used by the IHD to locally calculate the cost of the electricity consumed, as well as Daylight Savings Time IHD clock adjustments. This software attracts annual licensing as well as monthly operational support costs. For the *peaksaver*PLUS® RDR CDM program, these costs are covered by the IESO program delivery budget.

For other potential future program offerings, such as the "*High Resolution Residential Load Disaggregation",* the following additional expenses could be expected:

- a low-cost ZigBee gateway device connected in "real-time" to the smart meter, for each customer participating in the program; and
- back-office software to take the high-resolution consumption information; complete the load disaggregation exercise; provide customer insights; notifications and reporting as required. A mobile app could be expected to be included as part of this program offering, to provide customers with further convenience, energy education and load management opportunities.

In order for such a program to be considered as a possible CDM program, a formal business case would need to be developed, demonstrating a positive cost-benefit under the IESO's CDM programming requirements.

If a potential program is considered as "behavourial change" only, it will be allocated a one-year CDM program persistence, essentially relegating the program as a viable CDM initiative for only the final year of the Conservation First Framework, 2020.

If not viable for CDM programs, distributors may consider such initiatives as "customer service", customer education" or "customer engagement" activities, and would need to consider them as rate base-funded activities.